ASX Announcement

Tuesday, 12 April 2022

ASX: WPL
OTC: WOPEY

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This announcement is an advertisement and not a prospectus for the purposes of the Prospectus Regulation Rules of the Financial Conduct Authority (FCA) or otherwise and is not an offer of securities for sale in any jurisdiction, including in or into the United States, Canada, Japan or South Africa.
Neither this announcement, nor anything contained herein shall form the basis of, or be relied upon in connection with, any offer or commitment whatsoever in any jurisdiction. Investors should not subscribe for or purchase any shares referred to in this announcement except solely on the basis of the information contained in the prospectus referred to herein (together with any supplementary prospectus, if relevant, the **UK Prospectus**), including the risk factors set out therein, published by Woodside today in connection with the proposed admission of ordinary shares in the capital of Woodside (the **Shares**) to the Standard Segment of the Official List of the FCA and to trading on the Main Market for listed securities of the London Stock Exchange plc (the **LSE**).

PUBLICATION OF UK PROSPECTUS

Woodside provides the following update on regulatory applications and secondary listings in connection with the proposed merger with BHP Group Limited's petroleum business (the **Merger**).

Woodside confirms that the Financial Conduct Authority (**FCA**) has approved the UK Prospectus prepared by Woodside in connection with the proposed admission of its Shares to the Standard Segment of the Official List of the FCA and to trading on the Main Market for listed securities of the LSE (**Admission**). The approval of the UK Prospectus should not be understood as an endorsement of the Shares admitted to trading on the LSE.

Admission is expected to become effective on completion of the Merger, targeted for 1 June 2022. The Merger is subject to satisfaction of certain conditions, including approval of the transaction by Woodside shareholders at Woodside's Annual General Meeting on 19 May 2022.

The UK Prospectus is attached to this announcement and will be available for inspection on Woodside's website at https://www.woodside.com.au/investors/woodside-and-bhp-proposed-merger and on the National Storage Mechanism at https://data.fca.org.uk/tf/nsm/nationalstoragemechanism.

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This ASX announcement was approved and authorised for release by Woodside's Disclosure Committee.

Cautionary note relating to compliance with Australian regulatory requirements

Nothing contained on this announcement constitutes a prospectus or disclosure document under Chapter 6D of the Corporations Act 2001 (Cth) and does not purport to include the information required of a prospectus or other disclosure document under Chapter 6D of the Corporations Act 2001.

The UK Prospectus includes information that complies with, and is presented in accordance with, the requirements of UK law. The presentation of this information may not be consistent with Australian law and regulation. Reserves and resources remaining are estimates that can vary based on the competent person deriving the estimate and the basis assumed. The reserves and resources information included in the UK Prospectus has been extracted from the Competent Person's Report prepared by Gaffney Cline & Associates Limited and accordingly may differ from information that Woodside has reported in accordance with ASX requirements.

Woodside shareholders and investors must exercise caution when reviewing the UK Prospectus, particularly in areas where regulatory requirements differ.

The information, and any other document issued by Woodside in connection with Admission, contains general information only and does not take account of the investment objectives, financial situation or particular needs of any person, and does not contain any securities recommendations or financial product advice. Before making an investment decision, investors need to consider whether the information in this document, and any other document issued by Woodside in connection with the Admission, is appropriate to their needs, objectives and circumstances, and, if necessary, seek expert advice on those matters.

Production or distribution of information in the US or to US Persons

This announcement relates to, and is issued solely in connection with, Admission. This announcement is not intended to and does not constitute an offer to sell or the solicitation of an offer to subscribe for or buy any securities, or a solicitation of any vote or approval with respect to the Merger or otherwise, nor shall there be any offer, solicitation or sale of securities, in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under securities laws of any such jurisdiction.

The securities referred to in this announcement may not be offered, sold or transferred, directly or indirectly, in, into or from the United States absent registration under the U.S. Securities Act of 1933 (the **Securities Act**) or pursuant to an applicable exemption therefrom, or in a transaction not subject to, the registration requirements of the Securities Act and in compliance with the securities laws of any applicable state or other jurisdiction of the United States. This announcement shall not constitute an offer to sell or the solicitation of an offer to buy any securities in the United States and may not be distributed, directly or indirectly within the United States. Neither the U.S. Securities Exchange Commission (the **SEC**) nor any state securities commission has approved or disapproved of the securities referred to in this announcement or passed upon the adequacy or accuracy of this announcement. Any representation to the contrary is a criminal offence in the United States.

Important legal information

The information contained in this announcement is for background purposes only and does not purport to be full or complete, nor does this announcement constitute or form part of any invitation or inducement to engage in investment activity. No reliance may be placed by any person for any purpose on the information contained in this announcement or its accuracy, fairness or completeness. The contents of this announcement are not to be construed as legal, financial or tax advice.

This announcement contains forward-looking statements. The words 'guidance', 'foresee', 'likely', 'potential', 'anticipate', 'believe', 'aim', 'estimate', 'expect', 'intend', 'may', 'target', 'plan', 'forecast', 'project', 'schedule', 'will', 'should', 'seek' and other similar words or expressions are intended to identify forward-looking statements. Similarly, statements that describe the objectives, plans, goals or expectations of Woodside are or may be forward-looking statements.

You should be aware that those statements and any assumptions on which they are based are only opinions and are subject to inherent known and unknown risks and uncertainties, many of which are beyond the control of Woodside. Those risks and uncertainties include factors and risks specific to the industries in which Woodside operates, as well as general economic conditions, prevailing exchange rates and interest rates and conditions in financial markets (for example (not exhaustive) price fluctuations, actual demand, currency fluctuations, geotechnical factors, drilling and production results, gas commercialisation, development progress, operating results, engineering estimates, reserve estimates, loss of market, industry competition, environmental risks, physical risks, legislative, fiscal and regulatory developments, economic and financial markets, conditions in various countries, approvals and cost estimates).

Investors are strongly cautioned not to place undue reliance on forward-looking statements, particularly in light of the current economic climate and the significant uncertainty and disruption caused by the COVID-19 pandemic and the conflict in Ukraine.

None of Woodside nor any of its related bodies corporate, nor any person named in this announcement or involved in the preparation of this announcement, makes any representation or warranty (either express or implied) as to the accuracy or likelihood of fulfilment of any forward-looking statement, or any events or results expressed or implied in any forward-looking statement. Accordingly, you are cautioned not to place undue reliance on those statements.

The forward-looking statements reflect views held only at the date of this announcement. Subject to any continuing obligations under the ASX Listing Rules or the Corporations Act, Woodside and its related bodies corporate, disclaim any obligation or undertaking to distribute after the date of this announcement any updates or revisions to any forward-looking statements to reflect any change in expectations in relation to those statements or any change in events, conditions or circumstances on which any statement is based.

The information in this announcement is subject to change. Persons viewing this announcement should ensure that they fully understand and accept the risks which will be set out in the UK Prospectus.

Persons considering making investments should consult an authorised person specialising in advising on such investments.

For the avoidance of doubt, the contents of Woodside's website are not incorporated by reference into, and do not form part of, this announcement.

This Prospectus comprises a prospectus relating to Woodside Petroleum Ltd prepared in accordance with the Prospectus Regulation Rules of the FCA made under section 73A of FSMA. This Prospectus has been approved by the FCA as competent authority under the UK Prospectus Regulation in accordance with section 87A of FSMA and made available to the public in accordance with Rule 3.2 of the Prospectus Regulation Rules. The FCA only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by the UK Prospectus Regulation. Such approval should not be considered as an endorsement of the company that is the subject of this Prospectus nor should such approval be considered as an endorsement of the quality of the securities that are the subject of this Prospectus. Prospective investors should make their own assessment as to the suitability of investing in the securities.

Applications will be made to the FCA and the London Stock Exchange for all of the Woodside Shares, including the New Woodside Shares, to be admitted to the standard listing segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities, respectively. Admission to trading on the Main Market constitutes admission to trading on a UK regulated market. It is expected that, subject to completion of the Merger, Admission will become effective and that dealings in the Woodside Shares will commence at 8.00 am (London time) on or around 6 June 2022. **The Merger is subject to satisfaction (or waiver, if permitted) of various Conditions. If the Merger does not proceed, then Admission will not take place.**

Woodside has established arrangements to enable investors to settle interests in the Woodside Shares through the CREST system. Securities issued by non-UK companies, such as Woodside, cannot be held or transferred electronically in the CREST system. However, the Depositary Interests allow such securities to be dematerialised and settled electronically through CREST. The Depositary Interests will be independent securities constituted under English law, which may be held and transferred through the CREST system. Investors should note that it is the Depositary Interests which will be settled through CREST and not the Woodside Shares.

Woodside Shares are currently listed on the ASX, where they will continue to be listed following Admission. Woodside will make an application to the ASX for quotation of the New Woodside Shares on the ASX. Woodside is seeking a secondary listing for all Woodside Shares, including the New Woodside Shares, on the standard listing segment of the Official List and to trading on the London Stock Exchange's Main Market for listed securities. In addition, Woodside has applied for the Woodside ADSs to be admitted to listing and trading on the NYSE.

This Prospectus is issued solely in connection with Admission. This Prospectus does not constitute or form part of an offer or invitation to sell or issue, or any solicitation of an offer to purchase or subscribe for, any securities by any person. No offer of Woodside Shares is being made in any jurisdiction.

Prospective investors should read this Prospectus in its entirety. In particular, your attention is drawn to Part 2 (*Risk Factors*) of this Prospectus for a discussion of the risks that might affect the value of your shareholding in Woodside. Prospective investors should be aware that an investment in Woodside involves a degree of risk and that, if certain risks described in this Prospectus occur, investors may find their investment materially adversely affected. Accordingly, an investment in the Woodside Shares is only suitable for investors who are particularly knowledgeable in investment matters and who are able to bear the loss of the whole or part of their investment.

Woodside Petroleum Ltd

(incorporated and registered in Australia with company number 004 898 962)

Woodside

Admission to the Official List (by way of a Standard Listing under Chapter 14 of the LSE Listing Rules) and to trading on the London Stock Exchange's Main Market for listed securities of the entire issued share capital of Woodside Petroleum Ltd

Financial Adviser

Morgan Stanley

English and Australian legal adviser

金杜律师事务所
KING&WOOD
MALLESONS

Notice to Australian Investors

This Prospectus does not constitute a prospectus or disclosure document under Chapter 6D of the Corporations Act 2001 and does not purport to include the information required of a prospectus or other disclosure document under Chapter 6D of the Corporations Act 2001.

This Prospectus, and any other document issued by Woodside in connection with the Merger and/or Admission, contains general information only and does not take account of the investment objectives, financial situation or particular needs of any particular person, and does not contain any securities recommendations or financial product advice. Before making an investment decision, investors need to consider whether the information in this Prospectus, and any other document issued by Woodside in connection with the Merger and/or Admission, is appropriate to their needs, objectives and circumstances, and, if necessary, seek expert advice on those matters.

Notice to South African Investors

Since the Merger and the Admission do not constitute an offer to the public as contemplated in the South African Companies Act, No. 71 of 2008 ("**South African Companies Act**") no prospectus is required to be filed with the South African Companies and Intellectual Property Commission in respect thereof. As a result, this Prospectus does not comply with the substance and form requirements for a prospectus or advertisements set out in the South African Companies Act and the South African Companies Regulations of 2011, and has not been approved by and/or registered with the South African Companies and Intellectual Property Commission.

In addition, the information contained in this Prospectus constitutes factual information as contemplated in section 1(3)(a) of the South African Financial Advisory and Intermediary Services Act, No. 37 of 2002, as amended ("**Fais Act**") and should not be construed as an express or implied advice, recommendation, guide or proposal that any particular transaction in respect of the Merger and/or Admission, is appropriate to the particular investment objectives, financial situations or needs of an South African investor, and nothing in this Prospectus should be construed as constituting the canvassing for, or marketing or advertising of, financial services in South Africa.

Notice to US Investors

Disclosure of reserve information and cautionary note to US investors

Unless expressly stated otherwise, all estimates of oil and gas reserves and contingent resources disclosed in this Prospectus have been prepared using definitions and guidelines consistent with the 2018 Society of Petroleum Engineers (SPE)/World Petroleum Council (WPC) / American Association of Petroleum Geologists (AAPG) / Society of Petroleum Evaluation Engineers (SPEE) / Society of Exploration Geophysicists (SEG) / Society of Petrophysicists and Well Log Analysts (SPWLA) / European Association of Geoscientists and Engineers (EAGE) / Petroleum Resources Management System (PRMS). Estimates of reserves and contingent resources in this Prospectus will differ from corresponding estimates prepared in accordance with the rules of the SEC and disclosure requirements of the U.S. Financial Accounting Standards Board ("**FASB**"), and those differences may be material. This Prospectus also includes estimates of contingent resources. Estimates of contingent resources are by their nature more speculative than estimates of proved reserves and would require substantial capital spending over a significant number of years to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from Woodside's properties may differ substantially. In addition, Woodside has made no commitment to drill, and likely will not drill, all of the drilling locations that have been attributable to these quantities.

The U.S. Registration Statement includes, among other things, disclosure of reserves and other oil and gas information in accordance with U.S. federal securities law and applicable SEC rules and regulations (collectively, "**SEC requirements**"). The SEC permits oil and gas companies that are subject to domestic issuer reporting requirements under U.S. federal securities law, in their filings with the SEC, to disclose only estimated proved, probable and possible reserves that meet the SEC's definitions of such terms. In addition, the U.S. Registration Statement includes notes to the financial statements included therein that include supplementary disclosure in respect of oil and gas activities, including estimates of proved oil and gas reserves and a standardised measure of discounted future net cash flows relating to proved oil and gas reserve quantities. This supplementary financial statement disclosure is presented in accordance with FASB requirements, which align with corresponding SEC requirements concerning reserves estimation and reporting.

No offer or solicitation

This Prospectus relates to, and is issued solely in connection with, Admission. This Prospectus is not intended to and does not constitute an offer to sell or the solicitation of an offer to subscribe for or buy any securities, or a solicitation of any vote or approval with respect to the Merger or otherwise, nor shall there be any offer, solicitation or sale of securities, in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under securities laws of any such jurisdiction.

The securities referred to in this Prospectus may not be offered, sold or transferred, directly or indirectly, in, into or from the United States absent registration under the U.S. Securities Act of 1933 (the "**Securities Act**") or pursuant to an applicable exemption therefrom, or in a transaction not subject to, the registration requirements of the Securities Act and in compliance with the securities laws of any applicable state or other jurisdiction of the United States. This Prospectus shall not constitute an offer to sell or the solicitation of an offer to buy any securities in the United States and may not be distributed, directly or indirectly within the United States. Neither the SEC nor any state securities commission has approved or disapproved of the securities referred to in this Prospectus or passed upon the adequacy or accuracy of this Prospectus. Any representation to the contrary is a criminal offence in the United States.

Important additional information and where to find it

In connection with the Merger, Woodside filed the U.S. Registration Statement with the SEC to register the distribution of the Woodside securities to be issued in connection with the Merger (including the prospectus therein). Woodside and BHP have also filed other documents with the SEC regarding the proposed Merger. This Prospectus is not a substitute for the U.S. Registration Statement or the prospectus or for any other document that Woodside or BHP may file with the SEC in connection with the proposed Merger. U.S. INVESTORS AND U.S. HOLDERS OF WOODSIDE AND BHP SECURITIES ARE URGED TO READ THE U.S. REGISTRATION STATEMENT, PROSPECTUS AND OTHER DOCUMENTS RELATING TO THE MERGER (INCLUDING ALL AMENDMENTS AND SUPPLEMENTS TO THOSE DOCUMENTS) THAT MAY BE FILED WITH THE SEC CAREFULLY AND IN THEIR ENTIRETY WHEN THEY BECOME AVAILABLE BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT WOODSIDE, BHP AND THE PROPOSED MERGER. Shareholders may obtain free copies of the U.S. Registration Statement, prospectus and other documents containing important information about Woodside and BHP once such documents are filed with the SEC. For more information on how to obtain a copy, please refer to paragraph 28 of Part 21 (*Additional Information*).

Exchange Act

Following Implementation, holders of Woodside Shares and Woodside ADSs will be subject to certain reporting requirements under the Exchange Act. Shareholders owning more than 5% of any voting class of equity securities registered pursuant to Section 12 of the Exchange Act, including ADSs representing beneficial ownership of 5% of the ordinary shares, must comply with disclosure obligations under Section 13 of the Exchange Act. Sections 13(d) and 13(g) of the Exchange Act require any person or group of persons who directly or indirectly acquires or has beneficial ownership of more than 5% of a voting class of an issuer's equity securities to file beneficial ownership reports electronically with the SEC on either Schedule 13D or on short form Schedule 13G, as appropriate, with the SEC.

Both Schedule 13D and Schedule 13G require background information about the reporting persons, including the name, address, and citizenship or place of organisation of each reporting person, the amount of the securities beneficially owned and aggregate beneficial ownership percentage, and whether voting and investment power is held solely by the reporting persons or shared with others.

This Prospectus has been prepared solely in respect of Admission and is being made publicly available for information purposes only and does not require any action to be taken by holders of Woodside Shares. Woodside is not offering any Woodside Shares nor any other securities in connection with Admission. This Prospectus does not constitute an offer to sell, or the solicitation of an offer to subscribe for or buy, any Woodside Shares nor any other securities in any jurisdiction. The Woodside Shares will not be generally made available or marketed to the public in the UK or any other jurisdiction in connection with Admission.

Morgan Stanley is authorised and regulated in the UK by the FCA. Morgan Stanley is acting for Woodside as financial adviser (and not as sponsor). Morgan Stanley is not acting for any other person in connection with Admission and Morgan Stanley will not regard any other person as its client in relation to Admission nor will it be responsible to anyone other than Woodside for providing the protections afforded to its clients or for providing advice in relation to Admission or any other transaction or arrangement referred to in this Prospectus. Morgan Stanley has not been engaged by Woodside as sponsor in connection with Admission and it will not be responsible to anyone (including Woodside) for providing the protections afforded to its clients for providing advice as sponsor in relation to Admission.

Morgan Stanley and/or any of their respective affiliates may have engaged in transactions with, and provided various investment banking, financial advisory and other services for Woodside, for which they would have received customary fees. Morgan Stanley and/or any of their respective affiliates may provide such services to Woodside and any of its affiliates in the future.

Apart from responsibilities and liabilities which may be imposed by the FSMA or the regulatory regime established thereunder, or under the regulatory regime of any other jurisdiction where exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, Morgan Stanley does not accept any responsibility, nor makes any representation or warranty (express or implied), for the contents of this Prospectus, including its accuracy or completeness, or for any other statement made or purported to be made by it, or on behalf of it, Woodside or any other person in connection with Woodside or the Woodside Shares. Accordingly, nothing contained in this Prospectus may be relied upon as any form of promise or representation in this respect. Morgan Stanley disclaims any responsibility or liability (save as referred to above) which it may otherwise have in respect of this Prospectus or any such statement.

Morgan Stanley has given and not withdrawn its consent to the issue of this Prospectus with the inclusion of the references to its name.

The application for Admission will be made in compliance with Rule 3 of the LSE Listing Rules.

Information to distributors

The distribution of this Prospectus in certain jurisdictions may be restricted by law. No action has been or will be taken by Woodside, BHP, the Directors or Morgan Stanley to permit possession or distribution of this Prospectus in any jurisdiction where it is believed that this may be unlawful or in contravention of local regulation. Persons into whose possession this Prospectus comes are required by Woodside, the Directors and Morgan Stanley to inform themselves about and to observe any such restrictions.

Application will be made for the Woodside Shares to be admitted to the standard listing segment of the Official List. A Standard Listing affords investors in Woodside a lower level of regulatory protection than that afforded to investors in companies whose securities are admitted to the premium segment of the Official List, which are subject to additional obligations under the LSE Listing Rules.

It should be noted that the FCA does not monitor Woodside's compliance with any of the LSE Listing Rules or those aspects of the DTR which Woodside has indicated herein that it intends to comply with on a voluntary basis, and is not authorised to impose sanctions in respect of any failure by Woodside to so comply.

Without prejudice to any obligation of Woodside to publish a supplementary prospectus pursuant to section 87G of FSMA or Rule 3.4 of the Prospectus Regulation Rules, the publication of this Prospectus may not be taken to imply that the affairs of the Group at any time subsequent to the date of this Prospectus are not subject to change or that the information in it is correct as of any time after the date of this Prospectus.

Neither Woodside nor any of its representatives, is making any representation to any investor in Woodside Shares regarding the legality or otherwise of an investment in Woodside Shares by such investor under applicable laws. The contents of this Prospectus are not to be construed as legal, business or tax advice. Each investor should consult their own legal adviser, business adviser, financial adviser or tax adviser.

Industry and Market Data

This prospectus contains industry, market and competitive position data that are based on industry publications and studies conducted by third parties as well as Woodside's internal estimates and research. These industry publications and third-party studies generally state that the information they contain has been obtained from sources believed to be reliable, although they do not guarantee the accuracy or completeness of such information. While Woodside believes that each of these publications and third-party studies is reliable, Woodside has not independently verified the market and industry data obtained from these third-party sources. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications and uncertainties as the other forward-looking statements contained in this prospectus and may differ among third-party sources. These forecasts and forward-looking information are subject to uncertainty and risk due to a variety of factors, including those described in the sections entitled "Risk Factors" and in "Cautionary Statement Regarding Forward-Looking Statements." These and other factors could cause results to differ materially from those expressed in each of Woodside's and BHP Petroleum's forecasts or estimates or those of independent third parties. While Woodside believes its internal research is reliable and its selection of industry publications and third-party studies and the description of its market and industry are appropriate, neither such research nor these descriptions have been verified by any independent source. In addition, references to "independent energy company" in this Prospectus exclude NOCs, companies with free float less than 60% (e.g., Lukoil, Wintershall Dea and Rosneft), major integrated oil and gas companies (e.g., ExxonMobil, Shell, Chevron, BP, ENI, Repsol and Total), and Canadian oil sands operators (e.g., Canadian Natural Resources, Cenovus and Suncor).

Woodside's website

Information contained on Woodside's website or the contents of any website accessible from hyperlinks on Woodside's website are not incorporated into and do not form any part of this Prospectus.

Interpretation

A list of defined terms used in this Prospectus is set out in Part 22 (*Definitions and Glossary*) of this Prospectus. A list of defined technical terms and conversions used in this Prospectus is set out in Part 23 (*Glossary of Technical Terms*) of this Prospectus.

References to the singular in this Prospectus shall include the plural and *vice versa*, where the context so requires. References to sections or Parts are to sections or Parts of this Prospectus. All references to time in this Prospectus are to London time unless otherwise stated.

Preferred currency

Unless specifically expressed otherwise, references to "**GBP**" or "**£**" are to the lawful currency of the UK, references to "**AUD**" or "**A$**" are to the lawful currency of Australia, and references to "**U.S. dollars**" or "**USD**" or "**US$**" or "**$**" are to the lawful currency of the United States.

Responsibility statement

Woodside and each of the Directors, whose names appear in Part 12 (*Directors, Senior Executives and Corporate Governance*) of this Prospectus, accept responsibility for the information contained in this Prospectus. To the best of the knowledge of Woodside and the Directors, the information contained in this Prospectus is in accordance with the facts and this Prospectus makes no omission likely to affect its import.

BHP accepts responsibility for the BHP Information. To the best of the knowledge of BHP, the BHP Information is in accordance with the facts and the BHP Information makes no omission likely to affect its import.

Date

Dated 11 April 2022

CONTENTS

Part 1 – Summary

Section A – Introduction and warnings

A.1 Introduction

This summary must be read as an introduction to this Prospectus. Any decision to invest in Woodside Shares should be based on consideration of this Prospectus as a whole by the investor. By deciding to invest in Woodside Shares, an investor could lose all or part of his or her invested capital.

Civil liability attaches only to those persons who have tabled the summary, including any translation thereof, but only if the summary is misleading, inaccurate, or inconsistent, when read together with other parts of this Prospectus, or it does not provide, when read together with the other parts of this Prospectus, key information in order to aid investors when considering whether to invest in such securities.

A.2 The name and ISIN of the securities

The securities being admitted to trading are the fully paid ordinary shares in the capital of Woodside (the "**Woodside Shares**"). At Admission, there will be an estimated 1,898,749,771 Woodside Shares in issue.[1] The ISIN of the Woodside Shares is currently AU000000WPL2 and is expected to change prior to Admission following Woodside's proposed change of name.

A.3 The identity and contact details of the issuer

The issuer is Woodside Petroleum Ltd (to be renamed Woodside Energy Group Ltd prior to Admission[2]). Woodside's registered office is 11 Mount Street, Perth WA 6000 Australia. Woodside's telephone number is +61 8 9348 4000 and email address is companyinfo@woodside.com.au. The LEI number for Woodside is 2549005ZC5RXAOO7FH41.

A.4 The identity and contact details of the competent authority approving the Prospectus

The head office of the Financial Conduct Authority ("**FCA**") is at 12 Endeavour Square, London E20 1JN, United Kingdom. The telephone number of the FCA is +44 (0)20 7066 1000.

This Prospectus was approved by the FCA on 11 April 2022.

Section B – Key information on the issuer

B.1 Who is the issuer of the securities?

Woodside Petroleum Ltd is a public company (to be renamed Woodside Energy Group Ltd prior to Admission[3]) incorporated and domiciled in Australia with company number 004 898 962. The principal legislation under which Woodside operates is the Corporations Act and legislation made thereunder. The LEI number for Woodside is 2549005ZC5RXAOO7FH41.

Woodside has been listed on the ASX since 18 November 1971 and is currently listed under the ticker ASX:WPL. Woodside will remain listed on the ASX following Admission.

Principal activities:

Woodside is an ASX listed oil and gas company based in Perth and is Australia's leading natural gas producer. Woodside operates the majority of its assets and has over 65 years' experience in the oil and gas industry. Woodside's producing portfolio is primarily centred around the production of LNG from conventional offshore projects in Western Australia but also includes oil, condensate, LPG and domestic gas for Western Australian customers. In addition to its producing assets, Woodside is constructing the Scarborough and Pluto Train 2 development in Western Australia and the Sangomar Field Development Phase 1 in Senegal.

The Merger:

On 17 August 2021, Woodside and BHP announced that they had entered into a Merger Commitment Deed, with an effective date of 1 July 2021, to combine their respective oil and gas portfolios through an all-stock merger.

[1] Based on number of Woodside Shares in issue at the Last Practicable Date and the estimated number of Woodside Shares to be issued on Implementation and assumes no additional Woodside Shares are issued between the Last Practicable Date and Implementation.
[2] Subject to approval by the Woodside Shareholders at the Woodside Shareholders' Meeting.
[3] Subject to approval by the Woodside Shareholders at the Woodside Shareholders' Meeting.

On 22 November 2021, Woodside and BHP entered into a binding Share Sale Agreement which sets out the parties' obligations in relation to Implementation of the Merger.

With the combination of two high quality asset portfolios, the Merger is expected to create a top 10 global independent energy company by production and the largest energy company listed on the ASX[4]. The Merger will be on a cash-free and debt-free basis, where BHP Petroleum will settle all intercompany loan balances prior to Implementation.

If the Merger is implemented, Woodside will acquire all of the issued share capital in BHP Petroleum International Pty Ltd, which holds BHP's oil and gas business, and Woodside will issue New Woodside Shares to BHP as part of the Merger Consideration which will be distributed by BHP to BHP Shareholders (or the Sale Agent in the case of all Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders).

The Merged Group will be owned approximately 52% by Existing Woodside Shareholders and 48% by BHP Shareholders (subject to adjustment in certain circumstances and subject to any BHP Shareholders being Ineligible Foreign BHP Shareholders or Relevant Small Parcel BHP Shareholders). The Merger is subject to satisfaction (or waiver, if permitted) of various Conditions including Woodside Shareholder Approval and regulatory and other approvals.

Major Shareholders:

As at the Last Practicable Date, Woodside is aware of the following persons who (together with their associates), directly or indirectly, hold interests in 5% or more of the Woodside Shares or voting rights as notified to Woodside under the Corporations Act. The table below also shows what these interests are expected to be on Admission, which will be following the issuance of the New Woodside Shares as part of Implementation.

Name	Number of Woodside Shares (pre-Implementation)	Percentage of issued share capital (pre-Implementation)[1]	Anticipated number of Woodside Shares (post-Implementation)	Anticipated percentage of issued share capital on Admission (post-Implementation)[2]
Blackrock Group (Blackrock Inc. and subsidiaries)	57,411,550[3]	5.83	120,866,917[4]	6.37
State Street Corporation and subsidiaries	50,409,641[5]	5.12	91,004,737[6]	4.79[2 3]

1 Based on number of Woodside Shares on issue as at the Last Practicable Date.
2 Based on the estimated number of Woodside Shares on issue at Implementation being 1,898,749,771.
3 This information is derived from the Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 30 May 2019, indicating ownership of Woodside's shares as of such date.
4 This information is derived from the Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 30 May 2019, indicating ownership of Woodside's shares as of such date and a Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 31 January 2022, indicating ownership of BHP shares as of such date.
5 This information is derived from the Notice of Initial Substantial Holder filed by State Street Corporation with the ASX on 8 November 2021, indicating ownership of Woodside's shares as of such date.
6 This information is derived from the Notice of Initial Substantial Holder filed by State Street Corporation with the ASX on 8 November 2021, indicating ownership of Woodside's shares as of such date and information provided by BHP to Woodside dated 14 February 2022 relating to the number of shares held by State Street Corporation.

Key managing directors:

Meg O'Neill is the Chief Executive Officer and Managing Director of Woodside.

The Woodside Board intend to appoint a current BHP director as a Woodside director following Implementation, although as at the date of this Prospectus no decisions have been made regarding such appointment.

Auditors:

Woodside's statutory auditor is Ernst & Young with its registered office at 11 Mounts Bay Road, Perth, WA 6000, Australia. Ernst & Young is registered to carry out audit work by the Australian Securities and Investments Commission and has no material interest in the Company.

On 14 October 2021, the Woodside Board selected PricewaterhouseCoopers to be the Company's auditor from the 2022 fiscal year. Such selection and change in auditor was adopted at the proposal of the Audit and Risk

4 Top 10 global independent energy company by hydrocarbon production. Woodside analysis based on the Wood Mackenzie Corporate Benchmarking Tool Q4 2021, 1 December 2021. See the section titled 'Disclaimer and Important Notices' for clarification of independent energy company.

Committee following a competitive tender process. This selection must be approved by Woodside Shareholders at the Woodside Shareholders' Meeting to be held on 19 May 2022. Accordingly, Ernst & Young, will retire as Company's auditor subject to regulatory approval from the Australian Securities and Investments Commission ("**ASIC**").

B.2 What is the key financial information regarding the issuer?

Historical Financial Information – Woodside:

The tables below set out summary historical financial information of the Woodside Group as derived without material adjustment from the annual consolidated financial statements of the Woodside Group for the financial years ended 31 December 2021, 31 December 2020 and 31 December 2019 (in each case, prepared in accordance with Australian Accounting Standards and complying with International Financial Reporting Standards as issued by the International Accounting Standards Board) (together, the "**Woodside Historical Financial Information**"). This information relates to periods prior to Implementation and, as such, does not include BHP Petroleum.

Summary consolidated income statement (US$m)

	Year ended 31 December		
	2021	**2020**	**2019**
Operating revenue	6,962	3,600	4,873
Cost of sales	(3,845)	(2,985)	(2,727)
Gross profit	**3,117**	**615**	**2,146**
Other income	139	(36)	100
Other expenses	(811)	(481)	(418)
Impairment reversals/(losses)	1,048	(5,269)	(737)
Net finance costs	(203)	(269)	(229)
Profit/(loss) before tax	**3,290**	**(5,440)**	**862**
Tax (expense)/benefit	(1,254)	1,465	(480)
Profit/(loss) after tax	**2,036**	**(3,975)**	**382**
Profit/(loss) attributable to:			
Equity holders of the parent	1,983	(4,028)	343
Non-controlling interest	53	53	39
Profit/(loss) for the period	**2,036**	**(3,975)**	**382**
Basic earnings/(losses) per share attributable to equity holders of the parent (US cents)	**206.0**	**(423.5)**	**36.7**

Summary consolidated statement of financial position (US$m)

	Year ended 31 December		
	2021	**2020**	**2019**
Assets			
Current assets	4,278	4,252	4,647
Non-current assets	22,196	20,371	24,706
Total assets	**26,474**	**24,623**	**29,353**
Liabilities			
Current liabilities	2,622	2,094	1,131
Non-current liabilities	9,623	9,654	10,813
Total liabilities	**12,245**	**11,748**	**11,944**
Net assets	**14,229**	**12,875**	**17,409**
Equity			
Issued and fully paid shares	9,409	9,297	9,010
Reserves	653	1,380	953
Retained earnings	3,381	1,398	6,654
Equity attributable to equity holders of the parent	**13,443**	**12,075**	**16,617**
Non-controlling interest	**786**	**800**	**792**
Total equity	**14,229**	**12,875**	**17,409**

Summary consolidated cash flow statement (US$m)

	Year ended 31 December 2021	2020	2019
Net cash from operating activities	3,792	1,849	3,305
Net cash used in investing activities	(2,941)	(2,112)	(1,238)
Net cash used in financing activities	(1,424)	(203)	317
Net (decrease)/increase in cash held	(573)	(466)	2,384
Cash and cash equivalents at the beginning of the period	3,604	4,058	1,674
Effects of exchange rate changes	(6)	12	—
Cash and cash equivalents at the end of the period	**3,025**	**3,604**	**4,058**

BHP Petroleum Historical Financial Information:

The tables below set out summary combined historical financial information of BHP Petroleum as derived without material adjustment from BHP's financial statements in respect of BHP Petroleum for (i) the half year ended 31 December 2021 (together with the half year ended 31 December 2020 for comparatives purposes) (unaudited), (ii) the financial years ended 30 June 2021 and 30 June 2020 (audited) and (iii) the financial year ended 30 June 2019 (unaudited) (together, the "**BHP Petroleum Historical Financial Information**"). The BHP Petroleum Historical Financial Information has been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Summary combined income statement (US$m)

	Half Year ended 31 December		Year ended 30 June		
	unaudited 2021	unaudited 2020	2021	2020	unaudited 2019
Revenue	3,198	1,602	3,909	3,997	5,867
Profit from operations	1,608	(199)	234	660	2,387
Profit/(loss) before tax	1,490	(437)	(174)	304	1,750
Tax (expense)/income	(907)	50	(187)	(482)	(1,089)
Profit/(loss) after tax from continuing operations	583	(387)	(361)	(178)	661
Loss after tax from discontinued operations	—	—	—	—	(335)
Profit/(loss) after tax from continuing and discontinued operations	**583**	**(387)**	**(361)**	**(178)**	**326**
Profit/(loss) attributable to:					
BHP shareholders	583	(387)	(361)	(178)	319
Non-controlling interests	—	—	—	—	7

Summary combined statement of financial position (US$m)

	Half Year ended 31 December		Year ended 30 June		
	2021	2020	2021	2020	2019
Assets					
Current assets	13,435	7,656	7,656	13,923	18,387
Non-current assets	13,723	14,579	14,579	14,386	13,117
Total assets	**27,158**	**22,235**	**22,235**	**28,309**	**31,504**
Liabilities					
Current liabilities	14,290	3,714	3,714	8,124	8,435
Non-current liabilities	4,894	15,409	15,409	15,461	18,132
Total liabilities	**19,184**	**19,123**	**19,123**	**23,585**	**26,567**
Net assets	**7,974**	**3,112**	**3,112**	**4,724**	**4,937**
Equity	**7,974**	**3,112**	**3,112**	**4,724**	**4,937**

Summary combined cash flow statement (US$m)

	Half Year ended 31 December 2021	2020	Year ended 30 June 2021	2020	2019
Net operating cash flows	1,388	106	1,060	585	2,821
Net investing cash flows	(543)	(980)	(1,520)	(1,033)	(1,387)
Net financing cash flows	(628)	766	910	(607)	(10,557)
Net (decrease)/increase in cash held	217	(108)	450	(1,055)	1,304
Foreign currency exchange rate changes on cash and cash equivalents	(1)	—	1	(1)	—
Cash and cash equivalents at the beginning of the period	776	325	325	1,381	77
Cash and cash equivalents at the end of the period	**992**	**217**	**776**	**325**	**1,381**

The above summary tables should be read together with the whole of this Prospectus.

Changes since end of last financial period:

Woodside – The financial performance of the Woodside Group has benefited from increases in commodity prices since 31 December 2021. There has been no other significant change in the financial performance or financial position of the Woodside Group since 31 December 2021, being the end of the last financial period of the Woodside Group for which financial information has been published, to the date of this Prospectus.

BHP Petroleum – The financial performance of BHP Petroleum has benefited from increases in commodity prices since 31 December 2021. There has been no other significant change in the financial performance or financial position of BHP Petroleum since 31 December 2021, being the end of the last financial period of BHP Petroleum for which financial information has been published, to the date of this Prospectus.

Unaudited Pro Forma Financial Information:

The table below sets out a summary of the unaudited pro forma financial information of the Merged Group ("**Unaudited Pro Forma Financial Information**") as derived from the financial statements in respect of the Woodside Group for the year ended 31 December 2021 (audited) and BHP Petroleum for the financial year ended 30 June 2021 (audited) and half year ended 31 December 2021 (unaudited), after making certain pro forma adjustments.

The Unaudited Pro Forma Financial Information has been prepared on the basis set out in the notes to the Unaudited Pro Forma Financial Information, in a manner consistent with the accounting policies applied by the Woodside Group in preparing its financial statements for the financial year ended 31 December 2021, and in accordance with the requirements of sections 1 and 2 of Annex 20 of the UK Prospectus Delegated Regulation. The Unaudited Pro Forma Financial Information has been prepared for illustrative purposes only. The hypothetical financial position or results included in the Unaudited Pro Forma Financial Information may differ from the Merged Group's actual financial position or results.

Unaudited Pro Forma Information	**Unaudited Pro Forma 31 December 2021 (US$m)**
Revenue	10,871
Net income (loss) attributable to common stockholders	1,504
Total assets	60,553
Total liabilities	24,038
Net assets	36,515

The above table should be read together with the whole of this Prospectus.

B.3 Profit forecast

Not applicable; this Prospectus does not contain profit forecasts or estimates.

B.4 What are the key risks that are specific to the issuer?

The global response to climate change is changing the way the world produces and consumes energy, creating risks for the Merged Group.

The Merged Group will be exposed to risks resulting from fluctuations in LNG market conditions or the price of crude oil, which can be volatile.

The Merged Group will operate in a high-risk industry and there are risks inherent in the Merged Group's exploration, development, production, and restoration activities.

Material limitations to the Merged Group's access to capital or a failure in financial risk management could adversely affect the Merged Group's business, results of operations and financial condition.

Woodside invests and, following Implementation, the Merged Group is expected to invest, significant amounts of funds in a variety of activities across the world which involve uncertainties and risks.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Merged Group's control.

The Merged Group operations will be subject to the risk of litigation or arbitration.

Woodside's and BHP Petroleum's operations are subject to extensive governmental oversight and regulation.

The Merged Group's operations will be subject to governmental and sovereign risks in the countries in which Woodside and BHP Petroleum do business.

Oversight and review by the ACCC in Australia, and other competition regulatory bodies in jurisdictions the Merged Group will operate in, may impact the Merged Group's businesses.

An inability to attract, retain and motivate skilled workers could adversely affect the Merged Group's business, operations and financial performance.

Section C – Key information on the securities

C.1 What are the main features of the securities?

Overview of shares:

The securities being admitted to trading are the Woodside Shares. At Admission, there will be an estimated 1,898,749,771 Woodside Shares in issue.[5] The ISIN of the Woodside Shares is currently AU000000WPL2 and is expected to change prior to Admission following Woodside's proposed change of name. Woodside's ticker symbol on Admission will be WDS, subject to shareholder approval of the proposed name change.

Securities of issuers domiciled outside the United Kingdom, such as Woodside Shares, cannot be held or settled directly in CREST. Woodside has therefore entered into depositary interest arrangements to enable investors from Admission to transact and settle trades of Woodside Shares, conducted on the LSE, within CREST. The Woodside Shares will not themselves be admitted to CREST; rather, the Depositary will issue the Depositary Interests in respect of underlying Woodside Shares which shall be capable of being held within CREST. Each Depositary Interest represents one underlying Woodside Share. The Depositary Interests are constituted under English law and held and transferred directly through the CREST system. Depositary Interests have the same ISIN as the underlying Woodside Shares and do not require a separate admission to trading on the LSE. The Depositary Interests will be created and issued pursuant to a Deed Poll issued and executed by the UK Depositary.

Following Admission, the price of the Woodside Shares will be quoted on the LSE in GBX.

Share rights:

The Woodside Shares are fully paid ordinary shares in the capital of Woodside.

The Woodside Shares rank equally for voting purposes. On a show of hands, each Shareholder present has one vote, and on a poll, each Shareholder has one vote per Woodside Share held.

The Woodside Shares rank equally for dividends declared and for any distributions on a winding-up.

5 Based on number of Woodside Shares in issue at the Last Practicable Date and the estimated number of Woodside Shares to be issued on Implementation of the Merger and assumes no additional Woodside Shares are issued between the Last Practicable Date and Implementation.

The Woodside Shares are freely transferable and there are no restrictions on transfer imposed by the Woodside Constitution.

Seniority:

The Woodside Shares rank equally in the right to receive a relative proportion of Woodside's assets upon dissolution and are the most senior security in Woodside's capital structure.

Dividend policy:

Woodside's dividend policy specifies that it will pay a minimum of 50% of net profit after tax excluding non-recurring items in dividends. The Woodside Board targets a dividend pay-out ratio between 50% and 80% of net profit after tax excluding non-recurring items subject to market conditions and investment requirements. Generally, Woodside pays dividends to Shareholders semi-annually, once in March or April and again in September or October of each year. Woodside maintains a dividend reinvestment plan that, if utilised by the Woodside Board, provides Shareholders with the option of reinvesting all or part of their dividends in additional Woodside Shares rather than taking cash dividends.

C.2 Where will the securities be traded?

Woodside Shares are currently traded on the ASX. Woodside will make an application to the ASX for quotation of the New Woodside Shares on the ASX.

In addition, Woodside will make applications to the FCA and the LSE for all of the Woodside Shares, including the New Woodside Shares, to be admitted to the standard listing segment of the Official List and to trading on the LSE's Main Market for listed securities. It is expected that Admission will become effective and that dealings will commence at 8.00 am on or around 6 June 2022. However, Admission is conditional on Implementation. The Merger is subject to satisfaction (or waiver, if permitted) of various Conditions. If the Merger does not proceed, then Admission will not take place.

Woodside has applied for the Woodside ADSs to listing and trading on the NYSE.

C.3 What are the key risks that are specific to the securities?

The market price of Woodside Shares may be volatile, and an active trading market may not develop or be sustained in the future in the United Kingdom.

There is no guarantee that dividends will be paid on Woodside Shares.

Substantial future sales of the Woodside Shares, or the perception that such sales might occur, or additional offerings of Woodside Shares could depress the market price of Woodside Shares.

Section D – Key information on the admission to trading on a regulated market

D.1 Under which conditions and timetable can I invest in this security?

Woodside will make applications to the FCA and the LSE for all of the Woodside Shares to be admitted to the standard listing segment of the Official List and to trading on the LSE's Main Market for listed securities. Admission is conditional on Implementation. If the Merger does not proceed, then Admission will not take place. It is expected that Admission will become effective and that dealings in the Woodside Shares will commence at 8.00 am on or around 6 June 2022.

Estimated transaction costs in connection with the Merger are US$410 million (excluding integration costs). No such expenses or any commissions or fees will be charged by Woodside to any investors in Woodside Shares in connection with the Merger or Admission.

D.2 Why is this Prospectus being produced?

The Prospectus is being produced in connection with Admission of the Woodside Shares following Implementation. The Woodside Directors believe a listing on the LSE, in addition to Woodside's ASX and NYSE listings, will benefit its new and more geographically diverse shareholder base and will assist in building Woodside's profile and provide a greater market for trading in Woodside Shares.

There are no material conflicts of interest pertaining to Admission.

Part 2 – Risk Factors

Investors should carefully review and consider the following risk factors and the other information contained in this Prospectus. The risks discussed herein have been identified based on an evaluation of the historical risks faced by Woodside and BHP Petroleum and relate to current expectations as to future risks that may result from the Merger. Certain of the following risk factors apply to the business and operations of Woodside and BHP Petroleum and will also apply to the business and operations of the Merged Group following Implementation. The occurrence of one or more of the events or circumstances described in these risk factors, alone or in combination with other events or circumstances, may adversely affect the ability to complete or realise the anticipated benefits of the Merger, and may have a material adverse effect on the business, cash flows, financial condition and results of operations of the Merged Group following Implementation. This could cause the trading price of the Woodside Shares to decline, perhaps significantly. Investors should carefully consider the following risk factors in conjunction with the other information included in this Prospectus, including the cautionary statements regarding forward-looking statements contained in Part 3 (*Presentation of financial and other information)*, Part 17 (*Operating and Financial Review of Woodside)*, the financial statements of Woodside, the financial statements of BHP Petroleum and notes to the financial statements included herein. The risks discussed below are not exhaustive and are based on certain assumptions made by Woodside and BHP Petroleum which later may prove to be incorrect or incomplete. Investors are encouraged to perform their own investigation with respect to the business, financial condition and prospects of Woodside, BHP Petroleum and the Merged Group. Each of Woodside, BHP Petroleum and the Merged Group may face additional risks and uncertainties that are not presently known to it, or that are currently deemed immaterial, which may also impair their respective businesses, financial conditions or results of operations.

Any investment in, or holding of, the Woodside Shares, carries a number of risks. Investors should review this Prospectus carefully and in its entirety (together with any documents incorporated by reference into it) and consult with their professional advisers. Investors should carefully consider the risks and uncertainties described below, together with the risks normally associated with companies of a similar nature to Woodside and, in particular, all other information in this Prospectus and the information incorporated into this Prospectus by reference, before making any decision in respect of the Woodside Shares.

Investors should note that the risks relating to the Merger, the Merged Group and the Woodside Shares summarised in Part 1 (*Summary*) of this Prospectus are the risks that the Board believes to be most essential to an assessment by a prospective investor of whether to consider an investment in the Woodside Shares. However, the risk factors described below are not an exhaustive list or explanation of all risks relating to the Merger, the Merged Group or Woodside Shares and should be used as guidance only. Additional risks and uncertainties relating to the Merger, the Merged Group and Woodside Shares that are not currently known to Woodside, or which may currently appear to be immaterial, may individually or cumulatively also have a material adverse effect on the Merged Group's business, results of operations, financial condition or prospects. If such risks were to materialise, the price of the Woodside Shares could decline as a consequence and investors could lose all or part of their investment.

The information given below is as of the date of this Prospectus and, except as required by the FCA, the LSE, the LSE Listing Rules, the UK Prospectus Regulation Rules or any other applicable law, will not be updated. Any forward-looking statements are made subject to the reservations specified under "Cautionary Statement Regarding Forward-Looking Statements" in Part 3 *(Presentation of Financial and Other Information)* of this Prospectus.

These risk factors do not consider the individual investment objectives, financial situation, position or particular needs of individual investors. If an investor does not understand any part of this Prospectus (including these risk factors) the investor should consult their legal, financial, taxation or other professional adviser.

1 Risks Relating to the Merged Group

1.1 Climate change

The global response to climate change is changing the way the world produces and consumes energy, creating risks for the Merged Group. The complex and pervasive nature of climate change means transition risks are interconnected with and may amplify other risks. Additionally, the inherent uncertainty of potential societal responses to climate change may create a systemic risk to the global economy. If the Merged Group fails to adequately respond and adapt to the global response, its business, results of operations and financial condition could be materially adversely affected.

A recent report of the Intergovernmental Panel on Climate Change (IPCC, Working Group 1 contribution to the Sixth Assessment Report) states that "it is unequivocal that human influence has warmed the atmosphere, ocean and land." The Merged Group will be a major producer of energy-related products such as LNG, crude oil, condensate, pipeline gas and LPG which result in the generation of greenhouse gas emissions throughout their lifecycle. Additionally, the Merged Group's operations and properties will generate greenhouse gas emissions, particularly in Australia and the United States.

The complex and pervasive nature of climate change means that climate change risks are interconnected with and may amplify the Merged Group's other principal risks. Political and legal risks in relation to climate change include the possibility of executive and legislative change (such as the introduction of carbon pricing, modifications to the tax structure, tightening of restrictions on emissions, among others), delays, conditions or suspensions placed on regulatory approvals and litigation. Such political and legal risks may result in reduction or modification of certain operations, loss of lawsuits seeking to impose liability, or impairment of the Merged Group's ability to continue to operate in an economic manner. These may lead to increased costs or decreased opportunities in operations, delay projects, and may adversely change the demand for oil and gas products in the Merged Group's portfolio thereby reducing revenues, adversely impacting earnings and the value of its reserves and accelerating decommissioning obligations. "Green incentives" could help accelerate and de-risk investments in new energy technologies by competitors. Litigation could disrupt or delay regulatory approvals or impose financial costs.

Legislative and regulatory risks include the introduction of proposals by Australian lawmakers, the U.S. Congress and other governments intended to address climate change using different approaches, including but not limited to introducing or increasing direct limits on carbon emissions, emissions trading including in the form of baseline-and-credit or cap-and-trade schemes, a tax on carbon or greenhouse gas emissions, incentives for the development of lower-carbon technology, and renewable portfolio standards. In the U.S., many federal and state court cases have been filed in recent years asserting damage claims related to greenhouse gas emissions, and the results in those proceedings could establish adverse precedent that might apply to companies (including the Merged Group) that produce greenhouse emissions. Jurisdictions including the European Union have considered proposals to introduce "Border Adjustment Mechanisms" to apply carbon regulation to certain imported goods and services. The Merged Group could be materially and adversely affected if new legislation or regulations are adopted to address global climate change or if the Merged Group is subject to lawsuits for alleged damage to persons or property resulting from greenhouse emissions.

Technology risks include the cost of transition to lower emitting or less carbon-intensive technology in order to meet emission reduction targets and the risk of failure in novel technologies. These could increase the cost of achieving emission reduction targets and increase costs or reduce revenue from new products and services. The timing of technology development and deployment is uncertain which also results in a risk of increased cost or decreased revenue if the Merged Group's investments in new energy technologies are not timed to meet customer demand.

Market risks include changes to the price level and volatility of products that the Merged Group sells, thereby reducing revenues and adversely impacting earnings and the value of its reserves. Market risks also include changes to the price and availability of goods and services that the Merged Group purchases. These risks could arise due to climate regulation imposed upon customers and suppliers, product substitution as new forms of energy emerge, or other forms of change in final customer demand such as reductions in petroleum product demand due to faster than expected adoption of electric vehicles and other changes in consumer preferences.

Reputation risks include the risk of increased stakeholder concern and of stigmatisation of the broader carbon-intensive energy sector, or if emissions reduction and energy transition targets are not achieved and/or do not meet community expectations. This could affect the Merged Group's ability to attract and retain talent and capital, and may include shareholder activism. The Australian legal regime, where the majority of the Merged Group's assets and where its headquarters will be located, is generally conducive to shareholder activism. Shareholders have statutory rights to call shareholders' meetings, to requisition resolutions and remove directors. The increased public and private focus on climate change and greenhouse gas emissions may cause some investors to take steps to involve themselves in the governance and strategic direction of the Merged Group. Any such investor activism could increase costs, divert management's attention and resources, impact execution of business strategy and initiatives, create adverse volatility in the market price of the Merged Group securities or make it difficult to attract and retain qualified personnel and business partners.

Financial risks include the risk that investors invested in fossil fuel energy companies become increasingly concerned about the potential effects of climate change and may elect in the future to shift some or all of their investments into other sectors. Institutional lenders which provide financing to fossil fuel energy companies have also become more attentive to sustainable lending practices that favour renewable power sources such as wind and solar photovoltaic, making those sources more attractive, and some of them may elect not to provide funding for fossil fuel energy companies, or may make funding available on less competitive terms. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding for fossil fuel energy companies. Limitation of investments in and financing for fossil fuel energy companies could result in the restriction, delay or cancellation of new or expanded development or production activities as well as a reduction in the Merged Group's share price.

Physical risks include the potential exacerbation (frequency or severity) of existing weather conditions (for example cyclones or hurricanes), hot working conditions, rising sea levels and erosion which matters could have a material adverse effect on the Merged Group's assets and operations as well as the business of third-party vendors who supply necessary products and services in support of such operations.

1.2 Fluctuations in LNG market conditions and the price of crude oil

a. Supply and demand, market conditions and price movements

The Merged Group will be exposed to risks resulting from fluctuations in LNG market conditions or the price of crude oil, which can be volatile. Any material or sustained decline in LNG or crude oil prices, or change in buyer preferences, could have a material adverse effect on the Merged Group's results.

Both Woodside's and BHP Petroleum's revenues are primarily derived from sales of LNG, crude oil, condensate, pipeline gas and LPG. Consequently, the results of operations of both businesses are strongly influenced by the prices they receive for these products, which in the case of oil and condensate are primarily determined by prevailing crude oil prices and in the case of pipeline gas, LPG and LNG are primarily determined by prevailing crude oil prices as well as some fixed pricing and other price indexes (such as Henry Hub and the JKM). For the year ended 31 December 2021, the majority (approximately 81%) of Woodside's production was attributed to natural gas, comprising LNG, LPG and pipeline gas and the remaining portion (approximately 19%) of Woodside's production was attributed to oil and condensate. That production mix differs from BHP Petroleum, which for the year ended 31 December 2021, was approximately 63% natural gas, comprising LNG, LPG and pipeline gas, and 37% oil and condensate (excluding Algeria and Neptune production). Overall BHP Petroleum has a lower weighting of LNG in its portfolio contrasted with Woodside. As a result, BHP Petroleum has relatively less exposure to the value of LNG relative to oil. In this context, the Merger will result in Woodside Shareholders diversifying their exposure from LNG, while Eligible BHP Shareholders who continue to hold Woodside Shares or Woodside ADSs following the Merger will increase their exposure to LNG.

LNG market conditions, including, but not limited to, supply and demand, are unpredictable and will be beyond the Merged Group's control. In particular, supply and demand for, and pricing of, LNG remain sensitive to energy prices, external economic and political factors, weather, climate conditions, natural disasters (including pandemics), timing of FIDs for new operations, construction and start-up and operating costs for new LNG supply, buyer preferences for LNG, coal or crude oil and evolving buyer preferences for different LNG price regimes and the energy transition. Buyers and sellers of LNG are increasingly more flexible with the way they transact, and contracts may involve hybrid pricing that is linked to other indices such Brent or JCC. Typically, only LNG supplied from the U.S. was based on a component linked to movements in the U.S. Henry Hub plus certain fixed and variable components. This type of pricing structure may become a component of the weighted average price into Asia and other markets since LNG supply and trade has globalised and increasingly the lowest cost supply is setting the floor for long-term average global natural gas prices with transportation costs accounting for regional differences. This marginal supply is predominantly from the United States, indirectly pegging global gas prices and Asian spot LNG prices to the Henry Hub marker which could adversely affect the pricing of new LNG contracts and potential future price reviews of existing LNG contracts. Tenders may also be used by suppliers and buyers, typically for shorter-term contracts. In addition, long-term LNG contracts typically contain price review mechanisms which sometimes need to be resolved by expert determination or arbitration. The use of these independent resolution mechanisms are likely to be more prevalent in volatile commodity markets. Alternatives to fossil fuel-based products for the generation of electricity, for example nuclear power and renewable energy sources, are continually under development and, if these alternatives continue to gain market share, they could also have a material impact on demand for LNG, which in turn may negatively impact the Merged Group's business, results of operations and financial condition in the longer-term.

In early March 2020, oil prices experienced a precipitous decline in response to reduced oil demand due to the economic impacts of COVID-19 lockdowns and a fallout between Russia and Saudi Arabia, two of the 23 nations in OPEC+ (which is comprised of the 13 Organization of Petroleum Exporting Countries, and 10 non-OPEC members including Russia). OPEC+ had been balancing the market through supply management. Oil prices have rallied since the 2020 lows and in March 2022 were at multi-year highs as markets priced in geopolitical risk premiums relating primarily to Russia's invasion of Ukraine, exacerbating market uncertainty and energy market volatility. Oil prices can be very volatile, and periods of sustained low prices could result in changes to the Merged Group's carrying value assumptions and may also reduce the reported net profit for the relevant period.

Crude oil prices are affected by numerous factors beyond the Merged Group's control, including worldwide oil supply and demand. In addition to the recent impacts on oil prices resulting from those summarised above, the price of crude oil may be affected by other factors such as:

- the level of economic activity in the markets Woodside and BHP Petroleum serve;
- regional political developments and military conflicts (including the ongoing Ukraine conflict);
- economic sanctions;
- weather conditions and natural disasters;
- conservation and environmental protection efforts;
- the level of crude oil inventories;
- the ability of OPEC and other major oil-producing or oil-consuming nations to influence global production levels and prices;
- governmental regulations and actions, including the imposition of taxes and trade restrictions;
- market uncertainty;
- speculative activities by those who buy and sell oil and gas on the world markets, including commodity futures trading;
- availability and capacity of infrastructure, processing facilities and necessary transportation;
- supply chain disruptions;
- the price and availability of new technology;
- the availability and cost of alternative sources of energy; and
- the impact of climate change considerations and actions towards energy transition on the demand for key commodities which the Merged Group produces.

The transition to lower-carbon sources of energy in many parts of the world (driven by ESG and climate change concerns) may affect demand for the Merged Group's products, including crude oil, natural gas and LNG, which in turn may affect the price received (or expected to be received) for these products. Material adverse price impacts (including as a result of the energy transition) may affect the economic performance (including as to margins and cash flows) of, and longevity of production from, the Merged Group's existing and future production assets, and ultimately the financial performance of the Merged Group.

It is impossible to predict future crude oil, LNG and natural gas price movements with certainty. A low crude oil price environment or declines in the price of crude oil, in LNG and natural gas prices, could adversely affect the Merged Group's business, results of operations and financial condition and liquidity. They could also negatively impact its ability to access sources of capital, including equity and debt markets. Those circumstances may also adversely impact the Merged Group's ability to finance planned capital expenditures, including development projects, and may change the economics of operating certain wells, which could result in a reduction in the volume of the Merged Group's reserves. Declines in crude oil, LNG and natural gas prices, especially sustained declines, may also reduce the amount of oil and gas that it can produce economically, reduce the economic viability of planned projects or of assets that it plans to acquire or has acquired and may reduce the expected value and the potential commerciality of exploration and appraisal assets. Those reductions may result in substantial downward adjustments to the Merged Group's estimated proved reserves and require additional write-downs of the value of its oil and gas properties.

Sales contracts with the National Gas Company relating to production from BHP Petroleum's operations in the T&T are linked to ammonia pricing. Similar to crude oil, LNG and natural gas, it is impossible to predict future ammonia prices with certainty.

b. Exposure to short-term contracts and spot pricing

The Merged Group's exposure to shorter-term contracts and more volatile spot pricing (which can vary from time to time) could result in lower pricing in periods of LNG market over-supply.

A portion of the Merged Group's production will be exposed to shorter-term contracts and more volatile spot pricing, contrasted with long-term or medium-term contracts. In the past decade, there has been an increased prevalence of shorter-term contracts (i.e. spot sales and contracts with a duration of two years or less) and lower quantity contracts across the LNG market, although the share of total trade has tapered off slightly in recent years. It is anticipated that the proportion of such production of the Merged Group will vary from time to time. If the proportion of the Merged Group's production contracted on a shorter-term basis increases at any point in time, this may result in the Merged Group having increased exposure to deterioration in LNG market conditions.

Further, there is a risk that in a lower price environment, buyers are unwilling to commit to medium-term or long-term contracts, which may also result in the Merged Group having increased exposure to spot prices and LNG market volatility. Any increase in the Merged Group's percentage of uncommitted production could result in lower average realised prices during periods of LNG over-supply, which could have an adverse effect on the Merged Group's business, results of operations and financial condition.

c. Commodity and currency hedging

The Merged Group may be exposed to commodity and currency hedging.

There can be no assurance that the Merged Group will successfully manage its exposure to commodity prices. There is also counterparty risk associated with derivative contracts. If any counterparty to the Merged Group's derivative instruments were to default or seek bankruptcy protection, it could subject a larger percentage of the Merged Group's future oil and gas production to price changes and could have a negative effect on Woodside's financial performance, including its ability to fund future projects. Whether or not the Merged Group engages in hedging and other oil and gas derivative contracts on a limited basis or otherwise, the Merged Group will remain exposed to fluctuations in crude oil prices.

d. Interests in LNG and oil projects in construction

The Merged Group will have interests in LNG projects in construction which will increase the Merged Group's LNG production and LNG sales and, therefore, its reliance on the prices at which it is able to sell its LNG production to its customers.

Woodside and BHP Petroleum have interests in LNG projects in construction, for example, in the case of Woodside, the Scarborough and Pluto Train 2 development and the North West Shelf and Julimar Brunello upstream supply projects which will, if and when completed, supplement Woodside's LNG production and LNG sales and, therefore, its reliance on the prices at which it is able to sell its LNG production to its customers. Accordingly, negative movements in the LNG market may have a material adverse effect on Woodside's financial performance, including in relation to uncommitted production from existing facilities or from potential future developments.

The Merged Group's profits may be adversely affected by the introduction of new LNG facilities, or increased LNG throughput and expansion of existing LNG facilities (including those owned or operated by the Merged Group) in the LNG market, which could increase the supply of LNG and thereby lower prices. In particular, in both the Atlantic and Asia-Pacific markets, there is increasing LNG supply under construction and potential East African, North American, Qatari and Russian LNG projects, which may increase competition in the Atlantic and Asia-Pacific LNG markets. Such increases in the supply of LNG without a corresponding increase in demand for

LNG may lower LNG prices and the prices at which the Merged Group will be able to sell its LNG production to its customers. Decreases in LNG prices may materially affect the Merged Group's business, results of operations and financial condition.

e. Interests in oil projects in construction

The Merged Group will have a significant interest in oil projects in construction which will increase the Merged Group's crude oil production and crude oil sales and, therefore, its reliance on crude oil prices at which it is able to sell its production to its customers.

The Merged Group will have a significant interest in certain oil projects, including the Sangomar Oil Field Development and Mad Dog Phase 2, which are currently in construction and will, if and when completed, increase the Merged Group's crude oil production and crude oil sales and, therefore, its reliance on the prices at which it is able to sell its crude oil production to its customers. Accordingly, negative movements in the oil market may have a material adverse effect on the Merged Group's financial performance, including in relation to uncommitted production from existing facilities or from potential future developments.

1.3 Risks with oil and gas exploration, development and production activities

The Merged Group will operate in a high-risk industry and there will be risks inherent in the Merged Group's exploration, development, production and restoration activities, including a failure to find resources that can be commercialised successfully or the occurrence of operational or environmental hazards, which could adversely affect the Merged Group's business, results of operations and financial condition.

The Merged Group will have interests in a number of oil and gas exploration assets around the world, including in Australia, Senegal, South Korea, Congo, Egypt, T&T, U.S. GOM, Mexican Gulf of Mexico, Canada and Barbados, and it may increase its level of exploration in these and other locations around the world.

Furthermore, the Merged Group's operations could be impacted by operational hazards and environmental hazards. Operational hazards include, among others, the risk of fire, explosions, well blowouts, pipe failure and abnormally pressured formations. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharge of toxic gas.

Woodside's and BHP Petroleum's operations are often conducted in difficult or environmentally sensitive locations, in which the consequences of a spill, explosion, fire or other incident could be significant. Accordingly, inherent in the Merged Group's operations will be the risk that if it fails to manage operational hazards and abide by environmental and safety and protection standards, such failures could lead to damage to the environment and could result in regulatory action, legal liability, material costs and damage to the Merged Group's reputation or licence to operate. In certain circumstances, liability could be imposed without regard to the Merged Group's fault in the matter.

The Merged Group will have interests in deepwater fields and the Merged Group may attempt to pursue additional operational activity in the future and acquire additional fields and leases including in the deepwaters of the U.S. GOM and elsewhere. Exploration for oil or natural gas in deepwater generally involves significant operational, environmental and financial risks.

Operating or environmental hazards may cause the Merged Group to be unable to provide a safe environment for its workforce and the public which could lead to injuries or loss of life and could result in regulatory action, legal liability and damage to the Merged Group's reputation.

1.4 Financing

Material limitations to the Merged Group's access to capital or a failure in financial risk management, government fiscal, monetary and regulatory policy and variability in interest and exchange rates could all adversely affect the Merged Group's business, results of operations and financial condition.

The operating and financial performance of the Merged Group's business will be influenced by a variety of general economic and business conditions, including, among other things, access to debt and capital markets, government fiscal, monetary and regulatory policy and variability in interest and exchange rates. Deterioration in general economic conditions, including higher or lower than expected inflation rates or globally significant events, such as the ongoing COVID-19 pandemic or the conflict in Ukraine, and perception towards climate change and ESG matters, could have an adverse impact on the Merged Group's operating and financial performance and financial position.

The Merged Group may be unable to maintain Woodside's current credit rating due to a number of factors, including as a result of changes in its operating or business performance, a breach of debt covenants, changes in capital structures, changes in market conditions or through other strategic decisions. Changes to economic and business conditions, which are beyond the Merged Group's control may also limit its ability to access debt and capital markets on favourable terms. This may adversely impact the Merged Group's access to and cost of funding and its ability to fund growth and operational plans, which may have a material adverse effect on the Merged Group's business, financial condition and results of operations.

1.5 Significant investment of funds

Woodside invests and, following Implementation, the Merged Group is expected to invest, significant amounts of funds in a variety of exploration, development, production, construction, restoration, lower carbon services and new energy activities across the world, which involve many uncertainties and operating risks that could prevent it from realising profits or result in total or partial loss of its investment. This in turn may affect the Merged Group's business, results of operations and financial condition.

The Merged Group is expected to invest significant funds over the next several years on the Sangomar Oil Field Development and the Scarborough and Pluto Train 2 development and may invest significant funds over the next several years on other developments including Browse in Western Australia, Trion in Mexico, Calypso in T&T, Liard Basin in Canada, Greater Sunrise located between Australia and Timor Leste, and additional supply projects to existing producing assets as well as other exploration, development, restoration and new energy activities. These activities may involve many uncertainties and operating risks that could prevent the Merged Group from realising profits or result in the total or partial loss of its investment, putting pressure on its balance sheet and credit rating. Unforeseen issues, including increasing the required amount of capital expenditure necessary to complete a project, the impact of volatile crude oil, natural gas and LNG prices and the Merged Group's inability to enter into supply contracts with buyers in advance of an FID may cause the Merged Group not to proceed with any one or a combination of these activities.

In addition, even if the Merged Group and its joint venture participants decide that certain projects are economically viable, the Merged Group may not receive the necessary government and regulatory authorisations and permits to proceed with development, even where it may have incurred substantial costs in the evaluation process (for example, the North West Shelf and Browse environmental approval processes are ongoing). The Merged Group's projects will often require the use of new and advanced technologies, including in respect of the new energy activities of the Merged Group, which can be expensive to develop, purchase and implement, and may not function as expected. Some of the Merged Group's development projects will be located in deepwater or otherwise challenging environments, for example offshore of Western Australia and in the U.S. GOM or produced from challenging reservoirs. The Merged Group's projects could experience project implementation schedule slippage, shortages of or delays in the delivery of equipment or purpose-built components from suppliers, escalation in capital cost estimates, possible shortages of construction or other personnel, other labour shortages, environmental occurrences during construction that result in a failure to comply with environmental regulations or conditions on development, or delays and higher-than-expected costs due to the remote location of the projects, the impact of COVID-19 on the relevant workforce or supply chain, other unanticipated natural disasters, accidents, miscalculations, political or other opposition, litigation, acts of terrorism, operational difficulties or other events associated with that construction that may result in the delay, suspension or termination of the Merged Group's projects. This may result in further costs, the total or partial loss of the Merged Group's investment and a material adverse effect on the Merged Group's business, results of operations and financial condition.

The Merged Group's projects may be delayed, more costly than anticipated or unsuccessful for many reasons, including declines or unexpected volatility in oil and gas prices, misalignment between joint venture participants, cost overruns, changes in regulations, unanticipated financial, operational or political events, mechanical and technical difficulties, increases in operating cost structures, equipment and labour shortages, industrial actions or other circumstances. This may result in the delay, suspension or termination of the Merged Group's capital projects or the total or partial loss of the Merged Group's investment which may have a material adverse effect on the Merged Group's business, results of operations and financial condition.

1.6 Estimated petroleum reserves may not materialise

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors which will be beyond the Merged Group's control, which means the Merged Group's actual production with respect to its reserves may vary from those estimates, and the variances could be material.

Reserves are those quantities of gas, oil and condensate, 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 (as of the evaluation's effective date) based on the development project(s) applied. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors which will be beyond the Merged Group's control. Estimates of economically recoverable natural gas, crude oil and condensate reserves which are valid at a certain point in time are based upon a number of factors and assumptions, for example geological and engineering estimates and judgements (which have inherent uncertainties), the assumed effects of governmental regulation and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results and may alter significantly or become uncertain when new oil and gas reservoir information becomes available through additional drilling, or reservoir engineering over the life of the field. For example, if prices for LNG and crude oil remain depressed for extended periods of time, the Merged Group's estimates of certain of its reserves may be materially reduced. Those estimates are therefore, to some degree, variable, and classifications of reserves are always subject to a degree of uncertainty. For these reasons, estimates of the economically recoverable natural gas, crude oil and condensate reserves attributable to any particular group of properties and the classification of those reserves based on risk of recovery, prepared by different engineers or by the same engineers at different times, may vary substantially. The Merged Group's actual production with respect to its reserves may vary from those estimates, and the variances could be material.

Investors should note that different reserves reporting systems employ different assumptions, and that Woodside's methodologies for classifying reserves and Woodside's reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting and disclosure obligations of the SEC. As a result, because of the impact of these assumptions, identical raw data can produce varying estimates of reserves. Estimates of reserves are largely dependent on the interpretation of data obtained from drilling, testing and production and may prove to be incorrect over time. In addition, estimates of proved reserves that may be developed and produced in the future are frequently based upon volumetric calculations and by analogy to similar types of reservoirs, rather than upon actual production history. Subsequent evaluation of the same reservoirs based upon production history, additional data required, or further assessment may result in revisions to the estimated proved reserves. No assurance can be given that the reserves presented in this Prospectus will be recovered at the levels presented or that volumes will be maintained given ongoing evaluation work.

The definition of "proved reserves" under the Australian oil and gas reporting system varies in certain respects from the definition of "proved reserves" used by the SEC. If the Merger is implemented, Woodside will become subject to SEC reporting standards, and its proved reserves would need to be adjusted to comply with the SEC's reporting standards and the adjustments may be material.

Woodside estimates its reserves based on the Petroleum Resource Management System (PRMS) which is sponsored by the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), Society of Petroleum Evaluation Engineers (SPEE), Society of Exploration Geophysicists (SEG), Society of Petrophysicists and Well Log Analysts (SPWLA) and European Association of Geoscientists & Engineers (EAGE). This approach is also applied in the Competent Person's Report in Annexure 3 of Part 24 *(Competent Persons Report)*.

SPE PRMS is intended to provide a consistent set of standards and guidance used to estimate, classify and categorise a company's range of petroleum resources (prospective and contingent) and reserves. It is intended to reflect a company's project portfolio of undeveloped opportunities, its maturation and decision-making process and development plans, and capture the full life cycle value of base assets and growth projects.

This methodology differs from the SEC's rules, which require the use of more deterministic reserve determination methodologies, a standard approach to commodity price assumptions and more stringent timeframes for undeveloped reserves. This approach is intended to provide investors with a common set of rules to effectively compare corporation valuations.

Proved reserves estimated under SEC compliance could be lower than those determined using PRMS due to one or more of the following reasons: future commodity price assumptions, treatment of tariffs and royalties, exclusion of probabilistic aggregation, exclusion of off-block volumes as determined by rule-of-capture and exclusion of volumes below lowest know fluid contact.

1.7 Social licence to operate

Failure to meet stakeholder expectations could adversely affect the Merged Group and its future activities.

Stakeholders, such as investors, governments, traditional owners, employees, customers, community groups and suppliers, continue to have higher and evolving expectations of Woodside and oil and gas companies in general. Stakeholder groups are acting with greater levels of organisation, funding and sophistication, which has led to increased stakeholder activism with global reach, including increased stakeholder pressure on Woodside to provide transparency and apply ethical decision making. Stakeholders' attitudes and expectations of companies have shifted with respect to social responsibility, climate change, cultural heritage and the environment, which has influenced the regulatory landscape and increased scrutiny of oil and gas companies, including Woodside, and will also increase scrutiny of the Merged Group in the future. Some of the Merged Group's projects and activities will intersect with the interests of traditional owners and indigenous groups resulting in the Merged Group's relationships with these groups taking on particular significance.

A significant or continuous departure from these stakeholder expectations or the Merged Group's values, code of conduct or internal standards could adversely affect the Merged Group's reputation, relationships, brand, licence to operate and existing or future regulatory approvals.

1.8 Litigation or arbitration risks

The Merged Group operations will be subject to the risk of litigation or arbitration.

From time to time, the Merged Group may be subject to complaints, litigation or arbitration arising out of its operations. Damages claimed under such proceedings may be material, and the outcome of any litigation or arbitration could materially and adversely affect the Merged Group's reputation, business, results of operations or financial condition. Increasing attention on climate change issues may also lead to an increase in litigation on grounds of contribution to, or failure to mitigate the effects of, climate change. Additionally, there is an increase in the number of class action claims in respect of damages allegedly caused by contraventions of regulatory obligations, in particular claims which are climate, environment or cultural heritage related.

There is existing litigation in relation to the approvals granted to Woodside. For example, in December 2020 the Conservation Council of Western Australia filed applications seeking judicial review of certain decisions in respect of approvals that were granted in relation to the North West Shelf, Pluto and Pluto Train 2 projects (the Supreme Court of Western Australia dismissed the proceedings in March 2022); and in November 2021 Woodside was served with a further proceeding commenced by the Conservation Council of Western Australia seeking judicial review of a decision by the CEO of the Western Australian Department of Water and Environmental Regulation to grant Woodside a works approval for the Pluto Train 2 project granted in May 2021. It is expected there will be further challenges relating to other regulatory approvals commenced by project opponents.

The Merged Group may also be subject to challenges from litigants arguing breaches of duties of care (including in the nature of novel duties of care not to cause harm to Australian children, as contemplated in "Sharma (by their litigation representative Arthur) and Others v Minister for the Environment (Cth) and Another (2021) 391 ALR 1" judgment, which was over-turned on appeal). Climate-related litigation risks are also increasing as a number of entities have sought to bring actions against various oil and natural gas companies alleging, among other things, that such companies created public nuisances by producing fuels that contributed to climate change or alleging that the companies had been aware of the adverse effects of climate change but failed to adequately disclose those impacts. There is also a litigation risk as to whether a court would determine that the Merged Group's disclosure of climate change risk was inadequate.

While the Merged Group will assess the merits of each lawsuit and defend itself accordingly, it may be required to incur significant expenses in defending itself against any litigation or arbitration and there can be no assurance that a court or tribunal will find in its favour. If the Merged Group is unsuccessful in any litigation or arbitration, it may be subject to declaratory or injunctive relief (rather than compensatory damages) that is intended to force behavioural change, including but not limited to:

- requirements to seek approvals (with the risk of not being able to obtain that approval or obtaining the approval on less favourable terms);
- revocation of, or modification to, approvals that have already been granted;
- the imposition of conditions relating to approvals;

- injunctions which prevent the commencement of activities or stop existing activities from proceeding;
- compliance with emissions targets; and
- disclosure of documents, including board papers, relating to the Merged Group's assessment of climate risk.

Such proceedings, even if successfully defended, could have an adverse effect on the Merged Group's business, competitive position, prospects and reputation, and may divert the attention of its management team. In addition, proceedings in which the Merged Group is not directly subject may still impact its business and operations.

1.9 Regulatory oversight and dependence on licences, permits and approvals

Woodside's and BHP Petroleum's operations are subject to extensive governmental oversight and regulation, particularly with regard to the environment and occupational health and safety, that may change in ways that adversely affect the Merged Group's business, results of operations and financial condition.

Woodside's and BHP Petroleum's businesses are subject, in each of the countries in which they operate, to various national and local laws, regulations and approvals relating to the development, production, marketing, pricing, transportation and storage of its products, as well as the restoration of their properties. Therefore, a change in the laws or regulations (including in respect of their interpretation) that apply to their businesses or in the way in which the Merged Group will be regulated could have a material adverse effect on the Merged Group's business and financial condition. With increasingly heightened government and public sensitivity to environmental sustainability, climate change, and ESG matters, environmental regulation is becoming more stringent. Changes in environmental laws and regulations occur frequently and the Merged Group could be subject to increasing environmental responsibility and liability, including laws and regulations dealing with exploration and drilling, plugging and abandonment of wells, air quality, water and noise pollution and other discharges of materials (including greenhouse gases) into the environment, plant and wildlife protection, the reclamation and restoration of certain of the Merged Group's properties, greenhouse gas emissions, the storage, treatment and disposal of wastes and the effects of the Merged Group's business on the water table and groundwater quality. Any changes that impose additional requirements (including in respect of restoration) or restrictions on the Merged Group's operations or more stringent and costly waste management or clean-up requirements could result in substantial costs or impair the Merged Group's ability to operate profitably.

These laws and regulations may require the Merged Group to obtain licences, permits and approvals before activities commence, that restrict the types, quantities and concentrations of various substances that can be released into the environment, limit or prohibit construction or drilling activities in certain sensitive environments, require expanded corporate disclosure about operational impacts and corporate strategy on environmental matters, and impose substantial liabilities for violations of laws and regulations or for pollution resulting from former or current operations. Substantial compliance costs could impact the financial prospects of the Merged Group.

There is existing litigation and may be threats of, or possible future, litigation seeking to challenge approvals (either current or retrospective) that the Merged Group will hold in respect of certain development activities, including but not limited to approvals for new, or expansions to existing, projects. Some of these challenges and threats could relate to greenhouse gas emissions, environment, cultural heritage or human rights. There may be litigation in respect of the Merged Group's level of disclosure of climate change risk, including whether that disclosure is in accordance with legislation, or is in some way misleading or deceptive (akin to "greenwashing"), and related proceedings may give rise to claims for the disclosure of board and governance documents. The granting of approvals to the Merged Group under the Environment Protection and Biodiversity Conservation Act 1999 (Cth) may also be subject to challenges, including in relation to whether such approvals breach an existing or future duty of care (such as the novel duty of care to not cause harm to Australian children (as contemplated in "Sharma (by their litigation representative Arthur) and Others v Minister for the Environment (Cth) and Another (2021) 391 ALR 1" judgment, which was over-turned on appeal)).

If those threats materialise and/or the challenges are successful, new approvals may be required, there is a risk that those approvals will not be granted or, if they are, the Merged Group may be subject to more onerous conditions. There is also a risk of not obtaining relevant approvals, the revocation or modification of approvals that have been granted, or court orders enjoining certain development activities. There is also a risk that the legal action and threats will generate significant adverse publicity for the Merged Group, encourage similar suits to be brought in other jurisdictions or cause delay to the anticipated development schedule.

Revocation, failure to renew or alteration of the terms of the licences, permits or approvals required for the Merged Group's operations may negatively affect the Merged Group's business or results of operations.

Sanctions for non-compliance with these laws and regulations may include administrative, civil and criminal penalties, demand for reimbursement for government or regulatory actions, government orders, revocation of licences, permits, approvals, and corrective action orders. These laws sometimes apply retroactively. In addition, a party can be liable for environmental damage without regard to that party's negligence or fault. Therefore, the Merged Group could have liability for the conduct of others or for acts that were in compliance with all applicable laws at the time it performed them, including trailing liability for operations undertaken by purchasers of the Merged Group's assets.

In addition, governmental authorities may recommend or impose other measures that could cause significant disruptions to the Merged Group's business operations in the regions most impacted by COVID-19. The Merged Group's operational response to COVID-19, for example the change of crew rosters to ensure quarantine requirements are met, must meet regulatory expectations. Inadequate risk assessment or implementation of revised operating practices may result in regulator notices or the imposition of production limitations.

New regulations and legislation, as well as evolving practices, with respect to environmental, health and safety controls, and increased governmental oversight of operations, could increase the Merged Group's costs of regulatory compliance, impact its ability to capitalise on and/or to divest its assets and limit its access to new exploration properties.

In the United States, the exploration, production, transportation, and sale of oil and natural gas are subject to certain federal, state, and local laws and regulations. Current regulatory requirements may change or past non-compliance with regulations may be discovered. Because such laws and regulations are subject to amendment and reinterpretation over time, the Merged Group will be unable to predict the future cost or impact of complying with such laws.

Moreover, Woodside cannot predict whether new legislation to regulate the oil and natural gas industries in the United States might be proposed, what proposals, if any, might actually be enacted by the United States Congress, the applicable federal agencies, or the various state legislatures, and what effect, if any, the proposals might have on its or the Merged Group's future operations. The adoption and implementation of new or more stringent federal, state or local legislation, regulations or other regulatory initiatives that result in the imposition of more stringent standards for greenhouse emissions from the oil and natural industry could restrict the areas in which this sector may operate, and could result in increased compliance costs and changes in product pricing, which could impact consumer demand for Woodside's products.

1.10 Governmental and sovereign risks

The Merged Group's operations will be subject to governmental and sovereign risks, including political, legal and other uncertainties in the countries in which Woodside and BHP Petroleum do business, which could adversely affect the Merged Group's business, prospects, financial condition and results of operations.

Woodside's and BHP Petroleum's operations have been, and at times in the future the Merged Group's operations may be, affected by political developments and by national, state and local laws and regulations (including their interpretation or application), for example restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations (including in respect of restoration). Further, the Merged Group's operations and the products it produces will be the focus of increasing governmental policy initiatives and sovereign interests. Those initiatives and interests include environmental protection objectives, preservation of natural resources for national and state requirements, promotion of alternative energy uses, promotion of further exploitation of natural resources, local content requirements and other similar objectives. For example, BHP Petroleum's oil and natural gas operations in the United States and Mexico are subject to stringent federal, state and/or local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. The Merged Group will have exploration activities and potential projects outside Australia and in countries that are subject to various risks inherent in foreign operations in certain emerging markets with less stable legal, regulatory and political systems and where the geopolitical climates are changing. Further, the Merged Group's development and exploration activities in those countries, may be unlike any development and exploration activities that have taken place in those countries previously. In addition, the Glasgow Climate Pact calls upon parties to the United Nations Framework Convention on Climate Change to "accelerate efforts towards the phasedown of unabated coal power and phase-out of inefficient fossil fuel subsidies."

Future government policy objectives in the countries in which the Merged Group may do business could take the form of increased governmental regulations (including in respect of restoration), redirection of product distribution (such as domestic gas reservation policies), changes in taxation regulation or enforcement (including, for example, changes in tax rates on increased focus on audits), taxation subsidies or royalties, nationalisation of resource assets, limitations on periods of lease retention, interference with the confidentiality and availability of information, forced renegotiation of contracts, changes in laws and policies governing operations of foreign-based companies, trade sanctions, currency restrictions and exchange rate fluctuations and other governmental steps. For example, there is the potential of trailing liabilities for prior titleholders in respect of decommissioning in the countries in which the Merged Group will operate, which could lead to increased decommissioning costs. Such legislation has been introduced in Australia.

The Laminaria and Corallina Decommissioning Cost Recovery Levy has been enacted by the Australian government for the purpose of recovering the Commonwealth's costs of decommissioning the Laminaria and Corallina oil fields and associated infrastructure.

Furthermore, risks including war, insurrection, acts of terrorism and other political risks are, or may in the future be, present in some of the countries in which the Merged Group will do business.

The Merged Group may also be exposed to risks relating to bribery and corruption. Refusal to pay facilitation payments could result in disruption or delay to the Merged Group's operations and restriction on its ability to complete projects and secure further growth opportunities. Further, certain of the Merged Group's projects will be subject to government approvals from foreign governments, including some of whom will be the Merged Group's joint venture partners, and there is no assurance that those approvals will be obtained, which could adversely affect the Merged Group's business.

These potential governmental actions and risks could have a significant adverse effect on the Merged Group's operating model, and could subject the Merged Group's future operations, developments and exploration assets to delays and increased costs, or prohibitions on certain activities, the occurrence of which could have a material adverse effect on the Merged Group's business, results of operations and financial condition.

1.11 Competition regulation

Oversight and review by the ACCC in Australia, and other competition regulatory bodies in the jurisdictions in which the Merged Group will operate, may impact the Merged Group's investments and businesses.

Australia, the United States and most other countries in which the Merged Group will operate have laws designed to promote competition in business and to protect the interests of consumers. These laws prohibit certain conduct including cartel conduct between competitors, various arrangements/conduct that has the purpose, effect or likely effect of substantially lessening competition including "exclusive" supply or distribution arrangements, misuse of market power, concerted practices and anticompetitive mergers and acquisitions, and misleading or deceptive conduct. In August 2021, the ACCC proposed significant reforms to Australia's merger control regime, including mandatory notification thresholds and deeming acquisitions which would entrench, materially increase, or materially extend the substantial market power of the acquirer as having the effect of substantially lessening competition. The proposed reforms, if adopted by the Federal Government and enacted, and any adverse review, actions or decisions by the ACCC under current or future competition laws may prevent or limit the Merged Group's ability to pursue certain acquisitions.

If Woodside or BHP Petroleum is found to have contravened, or the Merged Group is found to contravene, applicable competition laws, the Merged Group may be subject to penalties and other court orders which may impact the Merged Group's financial performance, business and reputation.

1.12 Inability to attract and retain skilled workers and shortages of construction materials, equipment and supplies

An inability to attract, retain and motivate skilled workers could adversely affect the Merged Group's business, operations and financial performance.

The Merged Group's operations, development and restoration projects and exploration activities will require various types of skilled and semi-skilled workers, drawn from a range of professions, disciplines, trades and vocations. Competition for skilled personnel in the oil and gas industry is high. Constraints on the Merged Group's ability to attract, retain and motivate workers with appropriate skills and capabilities, including as a result of illness, quarantine, travel restrictions, other impacts of the COVID-19 pandemic or due to changes in the perception of oil and gas companies, could cause a shortage of workers or put increased pressure on wages, which could increase the Merged Group's capital and operating costs and otherwise adversely impact the Merged Group. Additionally, a considerable period of training and time may be required before new employees and contractors are equipped with the requisite skills to work safely and effectively. Any inability of the Merged Group, or of its key contractors, to obtain, motivate and retain workers could cause a labour capacity shortfall within the Merged Group's business, threaten the Merged Group's ability to deliver on its objectives and have an adverse effect on the Merged Group's business and financial condition.

Similarly, interference with the availability of labour due to industrial action could also impact negatively on the Merged Group's business performance. Any unionised part of the Merged Group's workforce could expose the Merged Group to industrial action (including strikes and work bans), the occurrence of which could disrupt the Merged Group's operations and adversely affect its financial condition and operating results.

1.13 Information technology systems

The Merged Group will be reliant on information technology systems and these may be subject to intentional or unintentional disruption, which could adversely impact the Merged Group's business and operations.

In general, the oil and natural gas industry has become increasingly dependent upon digital technologies to conduct day-to-day operations, including certain exploration, development and production activities. Both Woodside's and BHP Petroleum's operations rely on a number of information technology systems, applications and business processes utilised in the delivery of business functions.

This will expose the Merged Group to risks originating from adopting or implementing new technologies, or failing to take appropriate action to position the Merged Group for the digital future, which may impact the capabilities it requires, the effectiveness and efficiency of its operations and its ability to compete effectively. These risks, if realised, could lead to operational events, commercial disruption (such as an inability to process or ship products), corruption or loss of system data, a loss of funds, unintended disclosure of commercial or personal information, enforcement action or litigation. An inability to implement new technology may also adversely affect the Merged Group's licence to operate, reputation, results of operations or financial performance.

The Merged Group will use digital technology to estimate quantities of oil, LNG and natural gas reserves, process and record financial data, manage customers and to communicate with employees and third parties. The Merged Group's production facilities and operations will be dependent on the reliability and integrity of information technology systems. A breach or failure of information technology systems due to intentional actions, including attacks on cybersecurity, negligence or other reasons, or due to programme or system malfunctions, could result in the loss or misuse of data or sensitive information, injury to people, harm to the environment or the Merged Group's assets, legal or regulatory breaches, legal liability, disruption to its operations, interruptions to its services and processes, erroneous processing of third-party instructions and/or damage to its producing assets. Any intentional or unintentional disruption of the Merged Group's network security, information technology systems and any lack of availability of backup facilities may adversely impact its reputation, business and operations. The nature and timing of any disruptions will be unpredictable and largely outside the Merged Group's control.

Additionally, the Merged Group's information and operating technology systems and networks may be subject to, or be the target of, cyber-attacks, computer viruses, malicious code, phishing attacks or information security breaches that could result in the unauthorised release, gathering, monitoring, misuse, loss or destruction of confidential, proprietary and other information, or may otherwise disrupt the Merged Group's, or its customers' or other third parties' business operations or adversely impact safety.

1.14 Natural disasters or acts of terrorism

The Merged Group may encounter natural disasters or acts of terrorism (whether physical, cyber or otherwise), that may result in diminished production, additional costs or substantial loss.

Woodside and BHP Petroleum are, and the Merged Group will be, subject to operating hazards associated with the exploration for, and development, production and transportation of oil and gas. Natural disasters, inclement weather, acts of terrorism, operator error, disruption to supply chain or other occurrences can result in adverse events, including, without limitation, injury or loss of life, damage to or destruction of property (including oil and gas wells, formations and production facilities), diminished production, additional costs, loss of well control or blowouts, vessel collision, loss of containment of hydrocarbons and other hazardous material, pollution and other damage to the environment, labour disruptions, fires, explosions, equipment failure or other incidents. The Merged Group's offshore operations will be subject to marine perils, including severe storms and other adverse weather conditions and vessel collisions, as well as interruptions or termination by governmental authorities based on environmental and other considerations. The occurrence of any of these operating hazards could result in injuries or loss of life, regulatory action, legal liability and damage to the Merged Group's reputation and substantial losses to the Merged Group, all of which may affect its financial position and performance. There can be no assurance regarding the availability of insurance to cover any losses or liabilities associated with operational hazards, or that any insurance cover will be adequate to compensate for hazards.

Furthermore, acts of terrorism (whether physical, cyber or otherwise) against the Merged Group's facilities, pipelines, transportation, computer systems or employees could severely disrupt its operations, supply chain, cause loss of life and could have a material adverse effect on the Merged Group's business, financial condition and results of operations.

If an adverse event of this nature were to occur in the North West Shelf area off the north-west coast of Australia or the U.S. GOM, the impact on the Merged Group's operations and financial results could be magnified given the geographic concentration of the Merged Group's significant producing assets in these areas.

1.15 Replacement of petroleum reserves and exploration activity

The Merged Group is expected to continue to acquire or discover additional hydrocarbon resource volumes and commercialise them into proved reserves or further develop existing, acquired or discovered reserves to supplement its proved reserves and production (subject to satisfying the criteria set out in Woodside's capital allocation framework, energy replacement strategies and the overall energy transition).

The production rate of oil and gas properties declines as producing fields and reserves are depleted. Except to the extent that post-Implementation the Merged Group acquires further properties containing additional proved reserves, conducts successful exploration and development activities or identifies and develops additional proved reserves within Woodside's and BHP Petroleum's existing permits, after Implementation, the Merged Group's proved reserves will decline as its production continues. In addition, much of the Merged Group's interests will be in mature fields with declining production. Although the Merger is intended to reduce this risk, the Merged Group's future oil and gas production will remain dependent upon its level of success in acquiring, finding and/or developing additional proved reserves. Further, revisions to reserves occur from time to time as a result of other factors including completion of reservoir and subsurface studies. By way of example, there were several revisions to Woodside's proved reserves in 2021, including revisions to the Wheatstone proved reserves and the Greater Pluto proved reserves.

While Woodside is starting to progress new energy opportunities for the Merged Group, in the near term, its revenues and profits will continue to be predominantly derived from its oil and gas operations. As its energy portfolio evolves, the sustainability and growth of its operations and financial condition will continue to be underpinned by the success of its exploration, acquisition and development efforts and its ability to replace existing hydrocarbon resources. In addition, Woodside may choose to place a greater focus on growing the Merged Group's new energy portfolio, which may have a negative impact on the replacement of reserves. Failure to acquire or discover and develop new resources, or develop existing or acquired or developed resources in sufficient quantities, to maintain and grow the current level of the Merged Group's proven reserves after Implementation, would likely negatively affect its long-term results of operations and financial condition unless balanced by growth in its new energy portfolio.

Woodside expects to continue to evaluate and, where appropriate, the Merged Group will also pursue acquisition opportunities and the development of projects, including in established, emerging and new regions or markets. However, there is a risk that the Merged Group may not be able to identify suitable acquisition opportunities in the future or may not be able to successfully complete acquisitions, or it may acquire entities or assets that do not perform as expected. Similarly, the Merged Group may not be able to identify further projects that are economically feasible, or it may be unable to generate sufficient operating earnings or raise additional capital to meet the capital expenditure requirements necessary for development.

In conducting exploration and development activities from a particular reservoir or facility and associated wells, the risk of not finding hydrocarbons or experiencing unanticipated adverse outcomes such as irregularities in formations, miscalculations or operational issues may render the Merged Group's activities unsuccessful, potentially resulting in the abandonment of the well or development and a loss of its investment. In addition, it may be difficult to accurately predict timing requirements related to regulatory, environmental and community approvals in some regions which may result in construction delays. The Merged Group may not achieve its full growth strategy and potential, as the commercialisation of contemplated or planned projects, including with respect to assets it has discovered, acquired or plans to acquire, may deteriorate and require alternative technologies and/or lower cost developments to justify further investment. These factors may adversely affect the timing and/or economic value of new oil and gas opportunities, the expansion of the Merged Group's existing operations and its resulting financial performance and condition.

1.16 Energy transition risk

Woodside's objective to succeed in the energy transition may meet unforeseen challenges, including the pace of technological innovation, supply and safety of new sources of energy, regulatory and legal obstacles, financing limitations, engineering and technical know-how, and unexpected competition.

Woodside believes that the Merger is expected to create a larger, more financially resilient company, with increased scale and technical depth, enabling the Merged Group to better navigate the energy transition than either Woodside or BHP Petroleum could on a standalone basis.

However, there is uncertainty around the pace of required technological innovation and the reliability of technologies that will be needed to transition to a lower carbon environment. In addition, new sources of energy, such as hydrogen or ammonia, may be more difficult to commercialise than expected or may not be able to be commercialised safely or as efficiently as expected at scale. Woodside may also face unforeseen obstacles in the commercialisation of a future carbon capture business and in the implementation of other lower carbon services and emission reduction efforts.

There may also be regulatory, permitting or legal constraints that adversely affect the ability to capture, acquire, develop or supply new energy sources or reduce carbon emissions at the speed and scope currently anticipated, including constraints that are not yet known. The complex and pervasive nature of climate change means transition risks are interconnected with and may amplify other risks. Whilst it is currently expected that sources of funding will be receptive to new energy development, there can be no assurance that this will be the case and the ability to obtain financing, or the cost of funding may adversely impact development of projects necessary to succeed in the energy transition.

Technical and engineering skills needed for development of new energy initiatives may be different to those anticipated and unexpected disruptive technologies may adversely impact efforts by Woodside to implement its energy transition goals or projects commissioned as part of its energy transition. Woodside also cannot predict the rate at which other sophisticated parties may enter the same markets for new energy products and lower carbon services in which the Merged Group is expected to participate.

1.17 Emission allowances and carbon offsets

The availability and cost of emission allowances or carbon offsets could adversely impact the Merged Group's costs of operations and its ability to meet its environmental goals.

The Merged Group will be required to manage its emissions within regulatory limits in the ordinary course of operating its oil and gas wells and LNG facilities. Different regulatory regimes have different methods for setting these limits, such as the setting of baselines, the granting of allowances and the availability of use of different standards of carbon offsets. For example, in Australia, the Merged Group will be required to surrender carbon offsets for greenhouse gas emissions resulting from its domestic operations that exceed asset-specific regulatory baselines. If the Merged Group's operational needs exceed its allowed limits, it may have to curtail its operations, install costly new emission controls, or purchase allowances on the open market, which could be costly and may be limited by community or regulatory expectations. As the Merged Group will use the emission allowances or carbon offsets that it has purchased on the open market, costs associated with those purchases will be recognised as an operating expense. If those allowances are available for purchase, but only at significantly higher prices, the purchase of those allowances could materially increase the Merged Group's costs of operations in the affected markets.

There are numerous uncertainties inherent in estimating the quality and quantity of offsets generated by each of these projects, including many factors which will be beyond the Merged Group's control such as rainfall, bushfire and regrowth rates for native reforestation projects. Actual results may vary considerably from estimates, and the variances could be material. Accepted methods for estimating, calculating and certifying carbon offsets may in the future be varied resulting in a reduction in the number of carbon offsets generated or able to be used all of which may materially increase the Merged Group's costs associated with meeting regulatory or emission reduction targets.

In addition, a significant portion of the Merged Group's environmental sustainability plan beyond regulatory compliance will depend on its purchasing carbon offsets. If the prices of carbon offsets are higher than the Merged Group anticipates, the purchase of those offsets could materially increase its cost of operations and could materially limit its ability to meet its sustainability targets. In the future the use of carbon offsets to meet regulatory requirements or voluntary environmental sustainability plans may be limited by community or regulatory expectations which could require the Merged Group to curtail production or install costly new emission controls with adverse effects on the Merged Group's operating results. Alternatively, the change in community expectation on the use of carbon offsets could lead to failure to achieve emissions reductions targets with resulting damage to the Merged Group's reputation.

1.18 COVID-19 risk

The impacts of an epidemic or outbreaks of an infectious disease, such as COVID-19, could materially adversely affect the Merged Group's business, results of operations and financial condition.

The Merged Group will face risks related to the impacts of epidemics, outbreaks or other public health events that are outside of its control and could significantly disrupt its operations and adversely affect its business, results of operation and financial condition. For example, the ongoing COVID-19 pandemic could adversely affect the Merged Group's operations by rendering employees, contractors or vendors unable to work or unable to access its facilities for an indefinite period of time due to illness, quarantine or transportation and travel restrictions. The Merged Group may experience an impact to the timing and availability of key products or services from suppliers, or customer shutdowns to prevent spread of the virus both of which could negatively impact its business. In addition, the effects of COVID-19 and concerns regarding its global spread could negatively impact the domestic and international demand for crude oil and natural gas. This could contribute to price volatility, increase the Merged Group's counterparty risk, impact the price it receives for oil and natural gas and materially and adversely affect the demand for and marketability of the Merged Group's production. Restrictions on global shipping and limitations of the Merged Group's joint venture partners' ability to lift cargoes from producing facilities may result in maximum storage capacities being reached and a reduction in short-term production.

As the potential ongoing impact from COVID-19 is very difficult to predict, the extent to which it may negatively affect the Merged Group's operating results or the duration of any potential business disruption in the future is uncertain. The impact of current and future COVID-19 outbreaks will depend on future developments and new information that may emerge regarding the severity and duration of COVID-19 and the actions taken by authorities to contain it or treat its impact, all of which will be beyond the Merged Group's control. These potential impacts, while uncertain, could adversely affect the Merged Group's business, results of operations and financial condition.

1.19 Majority of major projects and operations in joint ventures

The majority of the Merged Group's major projects and operations will be conducted in joint ventures, and therefore the Merged Group's degree of control, as well as its ability to identify and manage risks, may be reduced.

A significant share of the Merged Group's capital has been or will be invested in joint venture assets and activities with other joint venture participants including NOCs. Such joint venture participants may have economic or business interests or objectives that are inconsistent with, or opposed to, the Merged Group's interests and objectives, and may exercise veto rights to block certain key decisions or actions that the Merged Group believes are in its or the joint venture's best interests or approve those matters without the Merged Group's support. In some instances, joint venture participants or contractual counterparties may be primarily responsible for the adequacy of the human or technical competencies and capabilities which they bring to bear on the joint project which will be out of the Merged Group's direct control. Additionally, partners or members of a joint venture may not be able to meet their financial or other obligations to the projects, which may threaten the viability of a given project or cause the Merged Group to incur additional costs associated with a given project. If the Merged Group was to experience misalignment with joint venture participants or other issues with joint decision-making, including in respect of preferred concept selection and funding of current and potential projects, the Merged Group could experience allegations of breach, delays in development of those projects or miss opportunities to pursue development at all.

In cases where the Merged Group is not the operator, it may be unable to control the behaviour, performance and cost of operations of joint ventures in which it participates. In these cases, the Merged Group will be dependent on joint venture participants acting as operators and its ability to direct operations or manage the timing and performance of any activity or the costs or risks involved may be reduced.

In addition, joint venture partners may default on their obligations due to insolvency, lack of liquidity, operational failure or other reasons. The inability of any joint venture partner to meet its obligations could have an adverse effect on the Merged Group's business, results of operations and financial condition.

1.20 ESG

Increased attention to environmental, social and governance ("ESG") matters and conservation measures may adversely impact the Merged Group's business.

Increased attention to climate change, societal expectations on companies to address climate change, as well as attention to matters relating to economic inequality, cultural heritage, energy and environmental justice, human capital management, diversity and corporate culture, has and is increasing investor and societal expectations regarding voluntary ESG practices and disclosures. These expectations and attention may in turn result in increased investor, media, employee and other stakeholder attention to the Merged Group's operations, ESG-related efforts and initiatives, and practices and policies relating to board, management and employee considerations, which could increase costs, have a negative impact on the Merged Group's reputation, brand and employee retention, and threaten the Merged Group's social licence to operate with customers and suppliers. In addition, consumer demand for alternative forms of energy may result in increased costs, shifts in consumer demand away from oil and natural gas products, reduced profits, increased investigations and litigation, and negative impacts on the ability of the Merged Group to access capital markets.

Moreover, while the Merged Group may create and publish voluntary disclosures regarding ESG matters from time to time, including disclosures regarding climate change risks, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated with them. Such expectations and assumptions are necessarily uncertain, may be dependent on estimates that are highly likely to change over time, and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. In addition, some of the Merged Group's voluntary disclosures will rely in part on third party data, and the Merged Group is not expected to independently verify third-party data. Further, it may take time to harmonise the Merged Group's disclosure and reporting regarding climate-related risks in the event that the climate reporting materially differed between Woodside and BHP Petroleum prior to the Merger.

In addition, organisations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions, and these ratings also may be used by other capital providers in assessing the Merged Group's creditworthiness. Unfavourable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward the Merged Group and the oil and gas industry and to the diversion of investment to other industries, which could have a negative impact on the Merged Group's access to and the costs of capital. Also, institutional lenders and certain capital providers may decide not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect the Merged Group's access to capital for potential growth projects

1.21 Competition in exploration, production and marketing

The Merged Group may face competition in the exploration, production and marketing of its products.

The exploration, production and marketing of hydrocarbon products is competitive, especially with regard to exploration for, and exploitation and development of, new sources of oil and natural gas. As many of the world's large oil fields approach natural depletion, incremental production is becoming increasingly difficult and therefore expensive. At the same time, new discoveries of conventional hydrocarbons are reducing in number and in size, while also tending to be more difficult to develop because of their location (e.g., remote or deepwater) or complexity. Production disruptions resulting from natural events, for example hurricanes or cyclones (which are prevalent in certain of the areas in which the Merged Group will operate, like Australia and the Gulf of Mexico) or significant health events which may disrupt the labour force (e.g., the ongoing COVID-19 pandemic), or due to social or geopolitical factors including terrorism or civil unrest, add to concerns about the security of oil and natural gas supplies.

The Merged Group will frequently compete for hydrocarbon resource acquisitions, exploration leases, licences, concessions and marketing agreements with major oil companies, government-backed national oil companies, independent oil and gas companies, individual producers, gas marketers and major pipeline companies, some of which may have larger financial and other resources than the Merged Group. These companies may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licences, than the Merged Group's financial or human resources permit. In addition, the Merged Group's competitors may include entities with greater technical, physical and financial resources that allow them to enjoy technological advantages, which may in the future allow them to implement new technologies before the Merged Group can. The Merged Group may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs.

If the Merged Group does not compete successfully for new LNG supply contracts, its business, financial condition and results of operations may be adversely impacted.

1.22 Fluctuations in exchange rates

The results of operations and financial conditions of the Merged Group will be subject to fluctuations in exchange rates.

Woodside's and BHP Petroleum's functional and presentation currency is U.S. dollars. While substantially all of Woodside's major sales contracts are, and have historically been, denominated in U.S. dollars, Woodside's operating costs and exploration and development expenses are incurred in a mix of currencies, predominantly Australian dollars and U.S. dollars. Those expenses include major construction, drilling and service contracts and shipping agreements. Some expenses, comprised primarily of the salaries of Australian employees, rent and payments to other local contractors are normally paid in Australian dollars. It is intended that the Merged Group will operate on the same basis.

Accordingly, after Implementation, movements in the exchange rates of any of these currencies relative to the U.S. dollar could adversely affect the Merged Group's results of operations and financial condition. Depreciation of the U.S. dollar, particularly against the Australian dollar, for prolonged periods, or exchange rate volatility, has in the past negatively affected Woodside's, and could in the future negatively affect the Merged Group's, profitability and financial position, and has increased, and could in the future increase, its effective costs.

Fluctuations in foreign currencies may also make period-on-period comparisons of the Merged Group's financial performance difficult. There can be no assurance that the Merged Group will successfully manage its exposure to exchange rate fluctuations or that exchange rate fluctuations will not have a material adverse effect on its future financial position and financial performance.

1.23 Tax consequences of the Merger for the Merged Group

Due to Woodside's expansion as a result of the Merger, including the expansion into additional jurisdictions in which the tax laws may not be favourable, Woodside's effective tax rate may increase and tax obligations may become significantly more complex and subject to greater risk of examination by taxing authorities, Woodside may be subject to tax inefficiencies as a result of its integration with BHP Petroleum, and Woodside may be subject to future changes in tax laws, in each case, the impacts of which could adversely affect Woodside's after-tax profitability and financial results.

After the Merger, Woodside will conduct operations, directly and through its subsidiaries, in Australia, the United States and multiple other foreign jurisdictions, and Woodside and its subsidiaries will therefore be subject to income taxes in such jurisdictions. In the future, Woodside may also become subject to income taxes in other jurisdictions. Woodside may be adversely affected by changes in the relevant tax laws and tax rates (including, for example, changes in the U.S. tax laws currently being considered by the United States Congress, if enacted), treaties, regulations, administrative practices and principles, judicial decisions, and interpretations thereof, in each case, possibly with retroactive effect in any such jurisdictions. In addition, Woodside's effective income tax rate and results of operations could be adversely affected by a number of factors, including changes in the valuation of deferred tax assets and liabilities, changes in accounting and tax standards or practices, changes in the composition of operating income by tax jurisdiction, changes in Woodside's operating results before taxes, and the outcome of income tax audits in Australia, and the United States or other foreign jurisdictions. In addition, Woodside may be subject to tax inefficiencies and other potentially adverse tax consequences as a result of the acquisition of BHP Petroleum, and Woodside may not be able to efficiently integrate and combine the Woodside and BHP Petroleum entity structures.

Due to the complexity of multinational tax obligations and filings, Woodside and its subsidiaries may have a heightened risk related to audits or examinations by federal, state, provincial, and local taxing authorities in the jurisdictions in which it operates. Outcomes from these audits or examinations could have a material adverse effect on Woodside's business, results of operations, or financial condition.

The tax laws of jurisdictions in which Woodside may operate in the future have detailed transfer pricing rules that require that all transactions with related parties satisfy arm's length pricing principles. Although Woodside believes that its transfer pricing policies have been reasonably determined in accordance with arm's length principles, it will need to coordinate and integrate these policies with the historic policies of the entities acquired in the Merger, and the taxation authorities in the jurisdictions where Woodside carries on business could challenge its transfer pricing policies. International transfer pricing is a subjective area of taxation and generally involves a significant degree of judgement. If any of these taxation authorities were to successfully challenge Woodside's transfer pricing policies, Woodside could be subject to additional income tax expenses, including interest and penalties. Any increase in Woodside's income tax expense and related interest and penalties could have a material adverse effect on its business, results of operations, or financial condition.

Woodside will regularly assess all of these matters to determine the adequacy of its tax liabilities and reserves, and if any of Woodside's assessments are ultimately determined to be incorrect, Woodside's business, results of operations, or financial condition could be materially and adversely affected.

1.24 U.S. federal income tax

The Merger could result in Woodside being treated as a U.S. corporation for U.S. federal income tax purposes.

Under current U.S. federal income tax law, a corporation generally will be considered to be a U.S. corporation for U.S. federal income tax purposes if it is created or organised in the United States or under the law of the United States or of any State. Accordingly, under generally applicable U.S. federal income tax rules, Woodside, which is incorporated and tax resident in Australia, would generally be classified as a non-U.S. corporation for U.S. federal income tax purposes. Section 7874 of the Internal Revenue Code (the "**Code**") and the U.S. Department of the Treasury (the "**U.S. Treasury**") regulations promulgated thereunder, however, contain specific rules that may cause a non-U.S. corporation to be treated as a U.S. corporation for U.S. federal income tax purposes. If Woodside were to be treated as a U.S. corporation for U.S. federal income tax purposes, this could result in a number of negative tax consequences for Woodside and holders of Woodside Shares or Woodside ADSs. For example, Woodside would be subject to U.S. federal income tax on its worldwide income and, as a result, could be subject to substantial liabilities for additional U.S. income taxes.

Based on the terms of the Merger and certain factual assumptions (including that BHP Petroleum (i) is properly classified as a foreign corporation for U.S. federal income tax purposes at the time of the Merger and (ii) has not acquired assets of a U.S. corporation or partnership in acquisitions related to the transactions contemplated in the Share Sale Agreement), Woodside does not believe that it will be treated as a U.S. corporation for U.S. federal income tax purposes under Section 7874 of the Code after the Merger. However, there can be no assurance that the investor's or Woodside's tax advisers, the Internal Revenue Service ("**IRS**"), or a court will agree with the position that Woodside is not treated as a U.S. corporation pursuant to Section 7874 of the Code. The rules for determining whether a non-U.S. corporation is treated as a U.S. corporation for U.S. federal income tax purposes are complex, unclear, and the subject of ongoing regulatory change. The position that Woodside is not treated as a U.S. corporation pursuant to Section 7874 of the Code is not free from doubt. Further, the application of such rules must be finally determined after completion of the Merger, by which time there could be adverse changes to the relevant facts, law, and other circumstances. For example, President Biden's Made in America tax plan, if enacted, would increase the risk that Woodside would be treated as a U.S. corporation by expanding the scope of such rules to capture more transactions. Holders of Woodside Shares should consult with, and rely solely upon, their own tax advisers regarding the application of the rules discussed above and any resultant tax consequences.

1.25 Impairments of goodwill or other intangible assets and application of accounting policies

The Merged Group's financial results could be adversely affected by impairments of goodwill or other intangible assets and the application of future accounting policies or interpretations of existing accounting policies including by regulatory direction, and changes in estimates of decommissioning costs.

Woodside may record a significant amount of goodwill attributable to the Purchase Price for BHP Petroleum. The effective date of the Merger is 1 July 2021, but the value of the Purchase Price (and, therefore, the amount of goodwill recognized) will be determined based on the price of the Woodside Shares and the fair value of the BHP Petroleum assets on the Implementation Date. On a pro forma basis at 31 December 2021, the amount of that goodwill is US$7.126 billion. This amount will differ from the actual amount recorded in connection with Implementation because of changes in, among other things, the market price of Woodside Shares and the estimates of fair value of BHP Petroleum's assets. Woodside periodically tests goodwill and other intangible assets for impairment and also if factors or indicators become apparent that would require an interim test.

Application of, or changes in, accounting policies and/or revisions in the fair value of one of the Merged Group's business segments could result in impairments of goodwill and non-cash charges. Any charge resulting from the application of accounting rules about impairment of goodwill and intangible assets could have a significant negative effect on the Merged Group's reported net income and its ability to pay dividends in one or more accounting periods if the level of impairment were to exceed profits available for distribution. In addition, the Merged Group's financial results could be negatively affected by the application of existing and future accounting policies or interpretations of existing accounting policies.

ASIC conducts regular reviews on a risk-basis of the financial reports of selected listed companies. As part of its financial reporting surveillance programme, ASIC raised concerns about certain infrastructure assets off Australian shores that were not included for full removal in the restoration provision in Woodside's financial report for the year ended 31 December 2020, and the adequacy of related disclosures. In response, in its most recent financial statements, Woodside provided additional disclosure on the inclusions and exclusions from that provision. Woodside is continuing to engage with ASIC and other relevant regulators on the appropriateness of Woodside's decommissioning provision and disclosure. Woodside also continues to monitor applicable regulatory developments and there is a risk that Woodside will need to make further provision in its financial statements (including in respect of the assets of BHP Petroleum once they are brought to account as part of the Merged Group) for removal in the future or give additional disclosures or both.

2 Risks Relating to Implementation of the Merger

2.1 Implementation is subject to Conditions

Implementation of the Merger is subject to certain Conditions and if these Conditions are not satisfied or waived in a timely manner, Implementation may be delayed or the Merger may not be implemented.

Implementation of the Merger is subject to the satisfaction or waiver of a number of outstanding Conditions. There can be no certainty, nor can Woodside provide any assurance or guarantee, that these Conditions will be satisfied or waived or, if satisfied or waived, when that will occur.

The satisfaction of a number of the outstanding Conditions is outside the control of Woodside and BHP, including, but not limited to, approval of the Merger by Woodside Shareholders and approvals, waivers, confirmations, exemptions or consents from certain regulators, including NOPTA. If the Conditions are not satisfied or waived on or before 30 June 2022 (or an agreed later date), either party to the Share Sale Agreement may terminate the Share Sale Agreement in accordance with its terms, in which case the Merger will not be implemented.

If, for any reason, a Condition is not satisfied or waived and the Merger is not implemented, there may be adverse consequences for Woodside and Woodside Shareholders. These include that the trading price of Woodside Shares may be affected, certain costs relating to the Merger will still be incurred and the anticipated cost savings, synergies and other benefits that Woodside expects to achieve from the Merger will not be realised, which may adversely affect Woodside's operational and financial performance and the market price of Woodside Shares.

The delay to satisfaction or waiver of Conditions could delay Implementation for a time or prevent it from occurring. Certain Conditions may only be satisfied subject to conditions or undertakings imposed by regulatory bodies or other third parties. Any delay in completing the Merger could result in Woodside not realising some or all of the benefits that it expects to achieve if the Merger is successfully completed within its expected timeframe, which may adversely affect Woodside's operational and financial performance.

In addition, BHP may terminate the Share Sale Agreement in accordance with the terms of the Share Sale Agreement. In certain circumstances (including where termination by BHP is in breach of the Share Sale Agreement), BHP has agreed to pay Woodside a reimbursement fee of US$160 million. Where payable, the payment of the reimbursement fee would be Woodside's sole and exclusive recourse against BHP.

2.2 Implications for Woodside if the Merger is not implemented

Failure to implement the Merger could negatively impact the price of Woodside Shares and the future business and financial results of Woodside, and Woodside may not realise the anticipated cost savings, synergies and other benefits that Woodside expects to achieve from the Merger.

If the Merger is not implemented, the anticipated cost savings, synergies and other benefits that Woodside expects to achieve from the Merger will not be realised, which may adversely affect Woodside's operational and financial performance and the market price of Woodside Shares.

Woodside estimates that it will incur transaction and integration costs in connection with the Merger, regardless of whether or not the Merger is implemented. Regret costs are estimated at US$100 million. In addition, in certain circumstances, Woodside has agreed to pay to BHP a reimbursement fee of US$160 million if the Merger is not implemented. This may adversely affect Woodside's capital and operating expenditure, which in turn may have a negative impact on its business, results of operations and financial condition.

Further, if the Merger is not implemented, BHP may between 1 July 2022 and 31 December 2022 exercise its Put Option under the Scarborough Put Option Deed to sell its interests in the Scarborough, Jupiter and Thebe Projects, including interests in certain key contracts and petroleum titles, to Woodside. If BHP exercises the Put Option, Woodside must pay US$1 billion in consideration to BHP (with expenditure adjustment from an effective date of 1 July 2021), and an additional US$100 million is payable by Woodside contingent on a future FID for a Thebe development. These circumstances may adversely impact Woodside, and Woodside may be required to fund (on a 100% basis) the capital expenditure for the Scarborough development. Any of these developments may have an adverse impact on Woodside's cash flows, financial performance and financial position.

If the Merger is not implemented, Woodside Shareholders will continue to be exposed to the various risk factors that currently apply to an investment in Woodside.

2.3 Acquisition risks

Woodside may be unable to verify the accuracy, reliability or completeness of all information it has received regarding BHP Petroleum and the Merger and the Share Sale Agreement may not adequately compensate Woodside for losses attributable to breaches of representations and warranties made by BHP in the Share Sale Agreement

Woodside has conducted due diligence investigations in connection with the Merger. As part of this, Woodside has relied on the information provided by BHP as well as on the due diligence investigations conducted by its employees and its advisers. To the extent that any investigation by Woodside's employees or advisers, or that any information provided to it, is incomplete, incorrect, inaccurate or misleading, the actual performance of the Merged Group may be different from what was expected, which may have an adverse impact on Woodside's financial position and performance.

Additionally, it is possible that the analysis Woodside has undertaken in connection with the Merger has resulted in conclusions and forecasts which are inaccurate, or which are not realised in due course, whether because of flawed methodology, misinterpretation of economic circumstances, tax treatment or otherwise. For example, there is a risk that the Merged Group will not be able to fully utilise certain tax attributes that are expected to transfer to the Merged Group. These include the rates at which tax loss benefits (for example, historic U.S. net operating losses of entities acquired from BHP) can be utilised and the availability of those losses to offset taxable income in any jurisdiction, which depends on many factors which cannot be assured. To the extent that the actual results achieved by the Merger are different than those anticipated by Woodside's analysis, there may be an adverse impact on Woodside's financial position and performance. To the extent that any investigation by Woodside's employees or advisers, or that any information provided to it, is incomplete, incorrect, inaccurate or misleading, the actual performance of the Merged Group may be different from what was expected, which may have an adverse impact on Woodside's financial position and performance. Further, given that BHP Petroleum International Pty Ltd is a wholly owned subsidiary of BHP, its securities are not publicly listed or priced, making it difficult to determine the value of the securities.

There is also no assurance that the due diligence conducted was conclusive, and that all material issues and risks in respect of the Merger have been identified and avoided or managed appropriately. Therefore, there is a risk that one or more issues may arise which will have a material impact on the Merged Group that were not identified through due diligence or for which there is no contractual protection for Woodside. This could adversely affect the business, results of operations and financial condition of the Merged Group.

2.4 Integration risks and realisation of anticipated synergies and other benefits

Woodside and the Merged Group will incur significant integration-related costs and challenges in connection with the Merger. Further, the success of the Merged Group and its ability to achieve the anticipated cost savings, synergies and other benefits of the Merger will partly depend on its ability to separate BHP Petroleum from BHP and integrate the businesses of Woodside and BHP Petroleum, including development, extraction and production operations, technology and personnel of each business.

There are risks associated with separating the business activities and operations of BHP Petroleum from BHP and then conducting and integrating the business activities and operations of BHP Petroleum into Woodside. While Woodside expects that it will be able to integrate BHP Petroleum's operations with its own, there is a risk that separation may take longer than expected, integration may take longer than expected (as a result of a delay in completion of separation activities or otherwise), or that integration may cost more than anticipated, including as a result of the COVID-19 pandemic and applicable physical separation requirements. Potential factors that may impact a successful integration include:

- disruption to the ongoing operations or business relationships of either or both businesses;
- disruption to project delivery;
- delays in separating BHP Petroleum from corporate services provided by BHP;
- higher than anticipated integration costs;
- unforeseen costs relating to integration of development, extraction and production operational systems, IT systems and financial and accounting systems of both businesses;
- extended period of transition services or duplicated activities due to delays in separation of BHP Petroleum and/or delays in implementing replacement processes or services; and
- unanticipated loss of key personnel or expert knowledge, or reduced employee productivity due to uncertainty arising as a result of the Merger.

The occurrence of any of these factors may adversely impact the Merged Group's operations, cash flows, financial performance and financial position. In addition, the demands that the integration process may have on management time may also cause a delay in other projects currently contemplated by Woodside and/or BHP Petroleum.

If integration is not achieved in an effective and timely manner, the full benefits of the combination of the two businesses, including the anticipated cost savings, synergies and other benefits that Woodside expects to achieve from the Merger, may be delayed or achieved only in part or not at all. This could adversely impact the Merged Group's business, results of operations and financial condition and the prospects of the Merged Group.

2.5 Material adverse change prior to Implementation

The Merger may be implemented even though material adverse changes may occur subsequent to the announcement of the Merger.

Under the terms of the Share Sale Agreement, either party can terminate the Share Sale Agreement if certain prescribed material adverse changes occur which affect the other party. However, certain types of changes do not permit either party to terminate the Share Sale Agreement or otherwise refuse to implement the Merger, even if such changes would have a material adverse effect on either of the parties. For example, a worsening of Woodside's or BHP Petroleum's financial condition or results of operations due to a decrease in commodity prices or general economic conditions would not give the other party the right to terminate the Share Sale Agreement or otherwise refuse to implement the Merger. In addition, the parties have the ability, but are under no obligation, to waive any material adverse change that results in the failure of a Condition and instead proceed with implementing the Merger.

If a material adverse change occurs that affects either party, but the parties are still required or voluntarily decide to implement the Merger, the Merged Group's business, results of operations and financial condition may suffer and the expected benefits of the Merger may not be realised as a result of the relevant material adverse change.

2.6 Separation of services to BHP Petroleum

Woodside may be unable to provide the same types and level of benefits, services and resources to BHP Petroleum that historically have been provided by BHP or may be unable to provide them at the same cost.

As part of BHP, BHP Petroleum has been able to receive benefits and services from BHP and has been able to benefit from BHP's financial strength and extensive business relationships. After Implementation, BHP Petroleum will be owned by Woodside and will no longer benefit from BHP's resources. While Woodside has entered into agreements under which BHP has agreed to provide certain transition services for a period of time following Implementation, there is a risk that Woodside will be unable to adequately replace those resources or replace them at the same cost. If Woodside is unable to replace the resources provided by BHP or is unable to replace them at the same cost or is delayed in replacing the resources provided by BHP, Woodside's business, financial condition and results of operations may be materially adversely impacted.

2.7 Dilution of Woodside Shareholders

After Implementation, Existing Woodside Shareholders will have significantly lower ownership and voting interests in Woodside than they currently have and therefore will exercise less control over management.

As part of the Merger, Woodside will issue a significant number of New Woodside Shares as the Share Consideration. Immediately after Implementation, it is expected that (based on the number of Woodside Shares outstanding on the Last Practicable Date and assuming that no additional Woodside Shares are issued in connection with a Permitted Equity Raise and no further declaration of Woodside Dividends will occur prior to Implementation) Existing Woodside Shareholders will own approximately 52% of the shares in the Merged Group and BHP Shareholders will own approximately 48% of the shares in the Merged Group (based on the issue of 914,768,948 New Woodside Shares and the number of Woodside Shares outstanding on the Last Practicable Date) subject to any BHP Shareholders being Ineligible Foreign BHP Shareholders or Relevant Small Parcel BHP Shareholders. Unless a Woodside Shareholder is also an Eligible BHP Shareholder, the Woodside Shareholder is likely to have its ownership and voting interests in Woodside diluted as a result of the Merger.

2.8 Historical Financial Information of BHP Petroleum

The BHP Petroleum Historical Financial Information may not be representative of its results or financial condition if it had been operated independently of BHP and, as a result, may not be a reliable indicator of its future results.

BHP Petroleum is currently owned by BHP. The BHP Petroleum Historical Financial Information included in this Prospectus has been prepared on a carve-out basis from the accounts of BHP and may not reflect what BHP Petroleum's financial position, results of operations or cash flows would have been had BHP Petroleum been an independent, stand-alone entity during the periods presented, nor are they necessarily indicative of the future financial position, results of operations or cash flows of BHP Petroleum. The combined financial statements of BHP Petroleum include all revenues and costs directly attributable to BHP Petroleum and an allocation of expenses related to certain BHP corporate functions. These expenses have been allocated to BHP Petroleum based on direct usage or benefit where identifiable, with the remainder allocated pro rata based on an applicable measure of headcount, usage of technology or other relevant measures. Although BHP Petroleum considers these allocations to be a reasonable reflection of the utilisation of services or the benefit received, the allocations may not be indicative of the actual expense that would have been incurred had BHP Petroleum operated as an independent, stand-alone entity, nor are they indicative of BHP Petroleum's future expenses.

2.9 Change of control or material transaction

Implementation of the Merger may trigger change of control or other provisions in certain agreements to which Woodside or BHP Petroleum are parties. If consents or waivers under the agreements are not obtained or granted, this may have an adverse effect on the Merger or the Merged Group.

Certain contracts to which Woodside, BHP Petroleum and their respective subsidiaries are party (including contracts with customers, lenders and joint venture partners) contain change of control or deemed assignment provisions that could be triggered by the Merger (including by entry into the Share Sale Agreement, Implementation, or other events in connection with the Merger). If any third party right of that type is triggered, it may allow the counterparty to review, adversely modify, exercise rights under or terminate the relevant contract. This may also result in Woodside or BHP Petroleum being obliged to pay termination fees or other fees or costs associated with the change of control or deemed assignment provision. If a counterparty were to do any of the foregoing, this may have an adverse effect on the Merged Group, which may be material. Agreements where such change of control provisions exist include agreements relating to assets in Barbados and Egypt, as well as various seismic contracts.

2.10 Business restrictions

Between the date of the Share Sale Agreement and Implementation, Woodside, BHP Petroleum and their respective subsidiaries' businesses are subject to restrictions on their business activities. These restrictions could adversely impact the Merged Group, or adversely impact Woodside if the Merger does not proceed to Implementation.

The Share Sale Agreement subjects Woodside and BHP Petroleum to certain customary restrictions on their respective business activities during the period between the date of the Share Sale Agreement and the earlier of Implementation and termination of the Share Sale Agreement. The Share Sale Agreement obliges each of Woodside and BHP Petroleum to use its commercially reasonable efforts to carry on its business in the ordinary course in all material respects, and the Share Sale Agreement obliges BHP Petroleum to use its commercially reasonable efforts to preserve substantially intact its business organisation, assets, the services of its current officers, employees and consultants and its goodwill and relationships with material customers, suppliers and others.

These restrictions could prevent Woodside and BHP Petroleum from pursuing certain business opportunities that arise during the period between the date of the Share Sale Agreement and the earlier of Implementation and termination of the Share Sale Agreement and could therefore adversely impact the Merged Group. Alternatively, if the Merger does not proceed to Implementation, the business and the future prospects of Woodside and BHP Petroleum could be adversely impacted.

2.11 Uncertainty about the effects of the Merger

Uncertainty about the effects of the Merger, including effects on employees, host governments, partners, contractors, regulators, suppliers and customers, may have a material adverse effect on the business, results of operations and financial condition of the Merged Group.

The Merger, and existing programmes of work to facilitate the Merger, may exacerbate existing risks relating to, among other things, the Merged Group's social licence to operate, climate change, environmental and social governance, people and culture, and regulatory compliance risks.

In addition, stakeholders that have business or other relationships with the Merged Group could defer consummation of a transaction or other decisions, or seek to change their existing business relationship with Woodside or BHP Petroleum.

The Merged Group will need to take action to prevent or minimise any detrimental impact to stakeholder relationships from the Merger and integration of Woodside and BHP Petroleum. No assurance can be given that these actions will be successful.

2.12 Tax consequences for Woodside Shareholders

If the Merger is implemented, there may be adverse tax consequences for investors.

The taxation of an investment in Woodside Shares depends on the individual circumstances of each investor and the tax impact may be different than expected. Investors should seek their own professional advice regarding the individual taxation consequences of the Merger.

2.13 Standalone accounting policies and methods

Woodside and BHP have particular accounting policies and methods and the integration of these accounting functions may lead to revisions which impact the Merged Group's reported results of operations and/or financial position and performance.

Woodside and BHP Petroleum, as standalone entities, have particular accounting policies and methods which are fundamental to how they record and report their financial position and results of operations. Woodside and BHP Petroleum may have exercised judgement in selecting accounting policies or methods, which might have been reasonable in the circumstances yet might have resulted in reporting materially different outcomes than would have been reported under the other company's policies and methods. The integration of Woodside's and BHP Petroleum's accounting functions may lead to revisions of these accounting policies, which may adversely impact the Merged Group's reported results of operations and/or financial position and performance.

3 Risks relating to the ownership of Woodside Shares

3.1 Woodside share price volatility and active trading of Woodside Shares in the United Kingdom

The market price of Woodside Shares may be volatile, and an active trading market may not develop or be sustained in the future in the United Kingdom.

Global stock markets in general, and Woodside Shares in particular, are subject to significant price and volume volatility. Woodside Shares historically have been, and New Woodside Shares following Implementation are expected to be, subject to significant fluctuations due to many factors, including but not limited to the pending Merger (in the case of pre-Implementation volatility of Woodside Shares); fluctuations in operating results, announcements regarding new projects, oil and natural gas exploration activities or technological advances by the Merged Group or its competitors; changes in earnings estimates by market analysts, and general market conditions or market conditions specific to particular industries; and any additional equity offering or future sales of Woodside Shares by Woodside, or the possibility of offerings or future sales.

These factors may make it more difficult for Woodside Shareholders to sell their Woodside Shares at a time and price which they deem appropriate and could also impede Woodside's ability to raise capital through the issue of equity securities.

The price of Woodside Shares may be subject to speculation in the press and the analyst community, changes in recommendations by financial analysts, changes in investors' or analysts' valuation measures, changes in global financial markets and global economies and general market trends unrelated to the performance of the Merged Group. The market price of Woodside Shares could be adversely affected by these factors and fluctuations.

Financial markets have experienced significant price and volume fluctuations in the last several years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Woodside Shares may decline even if the Merged Group's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. Also, certain institutional investors may base their investment decisions on consideration of the Merged Group's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in a limited or no investment in the Woodside Shares by those institutions, which could adversely affect the trading price of the Woodside Shares. There is no assurance that continuing fluctuations in the price and volume of publicly traded equity securities will not occur. If such increased levels of volatility and market turmoil continue, the Merged Group's operations could be adversely impacted, and the trading price of the Woodside Shares may be adversely affected.

In addition, Woodside has applied for the Woodside ADSs to be listed on the NYSE and for the Woodside Shares to be admitted to the standard listing segment of the Official List and to trading on the LSE's Main Market for listed securities. Liquidity on those securities exchanges may be significantly lower than on ASX with the result that the market price on one or both of those exchanges may be more volatile and/or less responsive to newsworthy developments in relation to Woodside and the value of its assets. Woodside Shares will be quoted in Australian dollars on ASX, and Pounds Sterling on LSE and Woodside ADSs will be quoted in U.S. dollars on NYSE.

Woodside can give no assurance that an active trading market for the Woodside Shares will develop in the United Kingdom or, if developed, can be sustained. If an active trading market is not developed or maintained, the liquidity and trading price of the Woodside Shares could be adversely affected.

Dividends in respect of the Woodside Shares, if any, will be declared in U.S. dollars. Fluctuations in exchange rates will affect, among other matters, the local currency value of the Woodside Shares and of any dividends. Holders, particularly non-Australian holders, may not derive a benefit from franking credits attached to a dividend, if any. These too may cause there to be temporary or more permanent differences in the value of Woodside Shares on different securities exchanges.

Multiple listing of the Woodside Shares (including in the form of Woodside ADSs) will result in differences in liquidity, settlement and clearing systems, trading currencies, prices and transaction costs between the stock exchanges upon which the Woodside Shares will be listed. These and other factors may hinder the ability to trade and transact the Woodside Shares (or corresponding Depositary Interests and/or Woodside ADSs) through one or more exchanges.

The future price of the Woodside Shares on ASX or LSE or the Woodside ADSs on the NYSE is uncertain and past performance is not indicative of future performance. Future share prices may be either above or below current or historical share prices. The trading in and liquidity of the Woodside Shares will be split among these three exchanges. The price of the Woodside Shares and Woodside ADSs may fluctuate and may at any time be different on ASX, LSE or NYSE. This could adversely affect the trading of the Woodside Shares or Woodside ADSs, as applicable, on these exchanges and increase their price volatility and/or adversely affect the price and liquidity of the Woodside Shares or Woodside ADSs, as applicable, on these exchanges.

3.2 No Guarantee of dividends

There is no guarantee that dividends will be paid on the Woodside Shares.

Whether any distribution is declared or paid to Woodside Shareholders, and the amounts of such distributions, are uncertain and depend on a number of factors. The Woodside Board will have discretion to declare or pay a distribution on Woodside Shares, which may be based on a number of considerations, including Woodside's dividend policy, its operating results and its capital management plans. In addition, if goodwill arising from the Merger were to be impaired to a level that exceeded available profits for distribution, there is a risk that dividends may not be payable in one or more financial periods (see the discussion of risks arising from impairment of goodwill).

3.3 Future sales of Woodside Shares

Substantial future sales of the Woodside Shares, the perception that such sales might occur, or additional offerings of Woodside Shares could depress the market price of Woodside Shares

Woodside cannot predict what effect, if any, future sales of Woodside Shares, or the availability of Woodside Shares for future sale, or the offer of additional Woodside Shares in the future, will have on the market price of Woodside Shares. Sales or an additional offering of substantial numbers of Woodside Shares in the public market, or the perception or any announcement that such sales or an additional offering could occur, could adversely affect the market price of Woodside Shares and may make it more difficult for Woodside Shareholders to sell their Woodside Shares at a time and price which they deem appropriate and could also impede Woodside's ability to raise capital through the issue of equity securities.

Eligible BHP Shareholders receiving New Woodside Shares at the Purchase Price may sell a significant number of the Woodside Shares they will be entitled to receive in the Merger, and such sales could be concentrated in the period shortly after Implementation. Further, there may be a perception by investors that Eligible BHP Shareholders will sell a significant number of Woodside Shares. These sales (and the perception of anticipated sales) could depress the market price of the Woodside Shares after Implementation. Sales of Woodside Shares by Woodside Shareholders that are not Eligible BHP Shareholders could also depress the market price of the Woodside Shares.

Additionally, it is possible that the sales by the Sale Agent on behalf of Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders may exert downwards pressure on the price of Woodside Shares in the period following the Implementation Date.

3.4 Enforceability of foreign proceedings

The ability of foreign shareholders to bring actions or enforce judgments against Woodside or the Woodside Directors may be limited.

The ability of a shareholder outside of Australia to bring an action against Woodside may be limited under Australian law. Woodside is a limited company incorporated in Australia and the rights of Woodside Shareholders are governed by Australian law and the Woodside Constitution. These rights may differ from the rights of shareholders in other jurisdictions, including the United Kingdom or the United States. Consequently, it may not be possible to effect service of process upon the Woodside Directors within a foreign shareholder's country of residence or to enforce judgments of courts of the foreign shareholder's country of residence, based on civil or commercial liabilities under that country's securities laws, against the Woodside Directors, the majority of whom are residents of Australia. In addition, courts in Australia or other courts may not impose civil liability on the Woodside Directors in any original action based solely on foreign securities laws brought against Woodside or the Woodside Directors in a court of competent jurisdiction in Australia or other countries.

As the rights and obligations of Woodside's shareholders are regulated by Australian corporations law, Woodside Shareholders must follow Australian legal requirements in order to exercise their rights, in particular the resolutions of the shareholders in general meeting may be passed with majorities different from the majorities required for the adoption of equivalent resolutions under English law or other laws.

3.5 Maintenance of multiple exchange listings

Liquidity in the market for Woodside securities may be adversely affected by Woodside's maintenance of three exchange listings.

Application has been made for the quotation of the New Woodside ADSs on NYSE, and Woodside will apply for the Woodside Shares to be admitted to the standard listing segment of the Official List and to trading on the LSE's Main Market for listed securities. Following Implementation, at which time New Woodside ADSs are expected to be listed and traded on the NYSE, Woodside intends to continue to list the Woodside Shares on ASX, with a secondary standard listing on the LSE. Woodside cannot accurately predict the effect of having its securities traded or listed on each of these markets. These secondary listings may, however, reduce the liquidity of Woodside's securities in one or more markets.

3.6 Standard Listing

Woodside is applying for a standard listing and, accordingly, it will not be required to comply with those protections applicable to a Premium Listing

Woodside is seeking a standard listing and, as a consequence, additional on-going requirements and protections applicable to a Premium Listing will not apply to Woodside. In particular, the provisions of Chapters 6 to 13 of the LSE Listing Rules (other than Rule 7.2.1), being additional requirements for a Premium Listing of equity securities (Premium Listing principles, sponsors, continuing obligations, significant transactions, related party transactions, dealing in own securities and treasury shares and contents of circulars), will not apply. In addition, a standard listing will not permit Woodside to gain UK FTSE indexation.

3.7 Depositary Interests

Certain Shareholders will be issued Depositary Interests in respect of underlying Woodside Shares

On Admission, holders of Woodside Shares will be able to hold and transfer interests in the Woodside Shares within CREST pursuant to a depositary interest arrangement established by Woodside. The Woodside Shares will not themselves be admitted to CREST; rather, the Depositary will issue the Depositary Interests in respect of underlying Woodside Shares. Holders of Depositary Interests may experience delays in receiving any dividends paid by Woodside, may receive voting instruction forms later than other Shareholders and will have to act earlier than other Shareholders when casting votes at general meetings of Woodside, by virtue of the administrative process involved in connection with holding Depositary Interests.

3.8 Position on a winding-up

If Woodside is wound up, distributions to Shareholders will be subordinated to the claims of creditors

On a winding-up of Woodside, holders of the Woodside Shares will be entitled to be paid a distribution out of the assets of Woodside available to Shareholders only after the claims of all creditors of Woodside have been met.

3.9 Suspension of trading

Trading in the Woodside Shares may be suspended

Woodside Shares are currently traded on ASX. In certain circumstances, the ASX have, and the LSE will have following Admission, the right to suspend trading in the Woodside Shares. If the Woodside Shares are suspended from trading, the holders of Woodside Shares may be unable to dispose of their Shares on the LSE or ASX (as the case may be).

The ASX also retains a general discretion to suspend trading in the Woodside Shares in circumstances where Woodside is unable or unwilling to comply with the ASX Listing Rules, to prevent a disorderly or uninformed market or for any other reason the ASX deems appropriate. The ASX will automatically suspend trading in the Woodside Shares if Woodside fails to lodge annual, half yearly and quarterly reports in accordance with the ASX Listing Rules or fails to pay the Company's annual ASX listing fee within 15 business days of the due date. The ASX may also suspend trading in Woodside Shares 5 business days following the issue of acquisition notices sent to shareholders pursuant to a compulsory acquisition under the Corporations Act.

The FCA may suspend the Woodside Shares from trading on the LSE if it determines that the smooth operation of the market is or may be temporarily jeopardised or that it is necessary to protect investors.

Woodside believes that as at the date of this Prospectus there are no circumstances which could provide grounds for the halting or suspending of the Woodside Shares from the LSE or ASX for the foreseeable future. However, there can be no assurance that any such circumstances will not arise in relation to the Woodside Shares in the future.

3.10 Delisting

Woodside may be delisted from the LSE or the ASX

In certain circumstances, the Woodside Shares may be delisted from the LSE or the ASX. Delisting could have an adverse effect on the liquidity of the Woodside Shares and on investors' ability to sell the Woodside Shares at a satisfactory price.

Woodside believes that as at the date of this Prospectus there are no circumstances which could provide grounds for the delisting of the Woodside Shares from the LSE or the ASX for the foreseeable future. There can, however, be no assurance that any such circumstances will not arise in relation to the Woodside Shares in the future.

Woodside may request that it be removed from the official list of the ASX at any time. However, the ASX may request that Woodside provide evidence that the request to be removed is made pursuant to appropriate authorisations or that the removal occurs subject to certain conditions being satisfied. The ASX's decision to approve the removal of Woodside from the official list of the ASX will typically be subject to certain conditions directed to ensure that the interests of the Shareholders are not unduly prejudiced by the removal. The ASX also retains a general discretion to remove Woodside from the official list of the ASX in various circumstances.

Woodside believes that as at the date of this Prospectus there are no circumstances which could provide grounds for the removal of Woodside from the official list of the ASX or the delisting the Woodside Shares from the LSE in the foreseeable future. However, there can be no assurance that any such circumstances will not arise in relation to the Woodside Shares in the future.

The FCA may cancel the listing of the Woodside Shares on the LSE if satisfied that there are special circumstances precluding the normal and regular dealings in the Woodside Shares.

The listing of the Woodside Shares on the LSE may also be cancelled at the request of Woodside, subject to Woodside giving notice of at least 20 Business Days' in England of the proposed cancellation of the listing. Because Woodside is seeking a Standard Listing, it would not be required by the LSE Listing Rules to seek shareholder approval in order to effect a cancellation of its LSE listing.

Part 3 – Presentation of Financial and Other Information

General

This Prospectus comprises a prospectus for the purpose of Article 6 of the Prospectus Regulation and is issued in compliance with the LSE Listing Rules. Investors should only rely on the information in this Prospectus. No person has been authorised to give any information or to make any representations in connection with Admission, other than those contained in this Prospectus and, if given or made, such information or representations must not be relied upon as having been authorised by or on behalf of Woodside or the Directors. Woodside does not accept any responsibility for the accuracy or completeness of any information reported by the press or other media, nor the fairness or appropriateness of any forecasts, views or opinions expressed by the press or other media regarding Woodside. Woodside makes no representation as to the appropriateness, accuracy, completeness or reliability of any such information or publication other than this Prospectus.

Without prejudice to any obligation of Woodside to publish a supplementary prospectus pursuant to FSMA, the delivery of this Prospectus shall not under any circumstances, create any implication that there has been no change in the business or affairs of the Woodside Group since the date of this Prospectus, or that the information contained herein is correct as of any time subsequent to its date.

The contents of this Prospectus or any subsequent communications from the Woodside Group or any of its respective affiliates, directors, officers, advisers, employees or agents, are not to be construed as legal, business or tax advice. Each prospective investor should consult its, his or her own lawyer, financial intermediary or tax adviser for legal, financial or tax advice. In making an investment decision, each investor must rely on its, his or her own examination, analysis and enquiry of Woodside, including the merits and risks involved.

This Prospectus is not intended to provide the basis of any credit or other evaluation and should not be considered as a recommendation by any of Woodside or the Directors or any of its representatives that any recipient of this Prospectus should purchase Woodside Shares. Prior to making any decision as to whether to purchase Woodside Shares, prospective investors should read this Prospectus. Investors should ensure that they read the whole of this Prospectus carefully and not just rely on key information or information summarised within it. In making an investment decision, prospective investors must rely upon their own examination of Woodside and the terms of this Prospectus, including the risks involved.

Presentation of financial information

The financial information presented in this Prospectus includes:

(i) annual audited consolidated financial statements of the Woodside Group for the financial years ended 31 December 2021, 31 December 2020 and 31 December 2019 (in each case, prepared in accordance with Australian Accounting Standards and complying with International Financial Reporting Standards as issued by the International Accounting Standards Board). Such financial information, being the Woodside Historical Financial Information, is referred to in Part 14 (*Historical Financial Information of the Merged Group*) and included at Annexure 1 of this Prospectus;

(ii) financial statements in respect of BHP Petroleum for (i) the half year ended 31 December 2021 (together with the half year ended 31 December 2020 for comparatives purposes) (unaudited), (ii) the financial years ended 30 June 2021 and 30 June 2020 (audited); and (iii) the financial year ended 30 June 2019 (unaudited). Such financial information (which has been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board), being the BHP Historical Financial Information, is referred to in Part 14 (*Historical Financial Information of the Merged Group*) and included at Annexure 2 of this Prospectus; and

(iii) certain unaudited pro forma financial information of the Merged Group as derived from the financial statements in respect of the Group for the year ended 31 December 2021 (audited) and BHP Petroleum for the financial year ended 30 June 2021 (audited) and half year ended 31 December 2021 (unaudited), after making certain pro forma adjustments as detailed in Part 15 *(Unaudited Pro Forma Financial Information)*.

For full details of the basis of preparation and significant accounting policies, please refer to the Basis of preparation in the Notes to the Woodside annual financial statements for each of the years ended 31 December 2019, 31 December 2020 and 31 December 2021 in Annexure 1 *(Woodside Historical Financial information)* and Note 1 of Annexure 2 (*BHP Historical Financial Information)* of this Prospectus.

Unless otherwise stated in this Prospectus, financial information referred to in this Prospectus has been extracted without material adjustment from the Historical Financial Information referred to in Part 14 (*Historical Financial Information of the Merged Group*) and included at Annexure 1 and Annexure 2 of this Prospectus. Unless otherwise indicated, none of the financial information relating to the Woodside Group or BHP Petroleum in this Prospectus has been audited.

Unaudited Pro Forma Financial Information

The Unaudited Pro Forma Financial Information has been prepared for illustrative purposes only and, because of its nature, addresses a hypothetical situation and does not, therefore, represent the Group's actual financial position or results. The Unaudited Pro Forma Financial Information has been prepared on the basis set out in the notes to the Unaudited Pro Forma Financial information contained in Part 15 (*Unaudited Pro Forma Financial Information*) of this Prospectus and in accordance with the requirements in sections 1 and 2 of Annex 20 of the UK Prospectus Delegated Regulation. The Unaudited Pro Forma Financial information is stated on the basis of the accounting policies of Woodside.

Non-IFRS financial measures

Overview:

This Prospectus contains various financial measures and ratios that are not presented in accordance with the International Financial Reporting Standards as issued by the International Accounting Standards Board ("**IFRS**") and which vary from the measures used by others in the same industry, including similarly titled measures used by others (collectively the "**Non-IFRS Financial Measures**"). Such Non-IFRS Financial Measures include:

- Earnings Before Interest and Taxes ("**EBIT**");
- Earnings Before Interest, Taxes, Depreciation and Amortisation ("**EBITDA**");
- Free Cash Flow; and
- Underlying Net Profit After Tax ("**NPAT**").

These Non-IFRS Financial Measures are defined in Part 17 (*Operating and Financial Review of Woodside*). Woodside includes these Non-IFRS Financial Measures in this Prospectus because the Directors believe that the Non-IFRS Financial Measures provide supplemental measures of performance and profitability, which Woodside uses for evaluating business performance and understanding certain significant items, which contribute to a better understanding of business trading performance. Furthermore, the Directors believe that these Non-IFRS Financial Measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance and profitability. EBITDA and Underlying NPAT are the measures used by management to assess business trading performance. Nonetheless EBITDA and Underlying NPAT have limitations as analytical tools, including the following:

- they do not reflect cash expenditures or future requirements for capital expenditure or contractual commitments;
- they do not reflect changes in, or cash requirements for, working capital needs;
- they do not reflect interest expense, or the cash requirements necessary to service interest or principal payments, on debt;
- although depreciation and amortisation are non-cash charges, the assets being depreciated and amortised will often have to be replaced in the future, and EBITDA and Underlying NPAT do not reflect any cash requirements for such replacements; and
- they exclude certain tax payments that may represent a reduction in cash available.

The Directors believe that the presentation of Non-IFRS Financial Measures in this Prospectus complies with the European Securities and Markets Authority ("**ESMA**") Guidelines on Alternative Performance Measures (dated 5 October 2015), and related ESMA Questions and Answers.

There are no generally accepted principles governing the calculation of Non-IFRS Financial Measures and the criteria upon which these measures are based can vary from company to company. Non-IFRS Financial Measures, by themselves, do not provide a sufficient basis to compare the Group's performance with that of other companies and should not be considered in isolation or as alternatives to revenue, profit before tax or cash flow from operating, investing and financing activities, as derived in accordance with IFRS or any other financial or performance measure derived in accordance with IFRS, and should not be considered as being indicative of operating performance or as a measure of the Group's profitability or liquidity. Non-IFRS Financial Measures should be considered only in addition to, and not as a substitute for or superior to, financial information prepared in accordance with IFRS included elsewhere in this Prospectus. Non-IFRS Financial Measures are not intended to be indicative of the Group's future results. Prospective investors are cautioned not to place undue reliance on the Non-IFRS Financial Measures and are advised to review them in conjunction with the Historical Financial Information included elsewhere in this Prospectus. For a reconciliation of appropriate measures derived in accordance with IFRS to the applicable Non-IFRS Financial Measures, see Part 17 (*Operating and Financial Review of Woodside*).

BHP Petroleum non-IFRS financial measures

BHP Petroleum also presents non-IFRS financial measures, Underlying EBITDA and net costs, which it believes are useful to help assess current operational profitability, excluding the impacts of sunk costs (i.e. depreciation from initial investment). BHP Petroleum also presents net costs, a non-IFRS financial measure, in connection with its presentation of BHP Petroleum unit costs, which BHP Petroleum believes provides a consistent benchmark relative to volumes that is in line with external market comparisons. BHP Petroleum also uses these non-IFRS financial measures to assess the performance of BHP Petroleum. These measures, however, should not be considered to be an indication of, or alternative to, corresponding measures of gross profit, net profit, cash flows from operating activities or other figures determined in accordance with IFRS. In addition, the measures may not be comparable to similar measures presented by other companies. For a reconciliation of appropriate measures derived in accordance with IFRS to the applicable Non-IFRS Financial Measures, see Part 18 (*Operating and Financial Review of BHP Petroleum*).

Key performance indicators

In evaluating the results of operations, the Directors refer in parts of this Prospectus to various key performance indicators relating to business performance. Save where indicated, these measures have been extracted from the management reporting systems of the Group and BHP Petroleum (as applicable) but have not been audited or reviewed by external auditors, consultants, independent experts or other third parties. In addition to the IFRS results of operations discussed in paragraph 2 of Part 17 *(Operating and Financial Review of Woodside*) and the Non-IFRS Financial Measures set out in the introductory paragraphs of Part 17 *(Operating and Financial Review of Woodside*), the following key performance indicators are used to evaluate the Group's performance:

- Gearing ratio;
- Gross margin;
- Liquidity;
- Net debt; and
- Return on average capital employed.

These key performance indicators are defined and set out in Part 17 (*Operating and Financial Review of Woodside*). These measures may not be comparable with similarly titled indicators presented by others in the same industry. These measures are not a measurement of performance or liquidity under IFRS and should not be considered in isolation or as a substitute for, or superior to, any IFRS measures of performance included in the Historical Financial Information.

Unaudited financial information

This Prospectus contains certain financial measures and other metrics that are unaudited. The Directors believe that each of these measures provides useful information with respect to the performance of the business and operations of the Woodside Group and BHP Petroleum (as applicable). Unaudited financial measures and other metrics in relation to the Woodside Group and BHP Petroleum have been derived from (i) management accounts for the relevant accounting periods presented; (ii) internal financial reporting systems supporting the preparation of the Historical Financial Information referred to in Part 14 (*Historical Financial Information of the Merged Group*) and included in Annexure 1 and Annexure 2 of this Prospectus; and (iii) other business operating systems and records of the Woodside Group and BHP Petroleum (as applicable). Management accounts are prepared using information derived from accounting records used in the preparation of the Historical Financial Information referred to in Part 14 (*Historical Financial Information of the Merged Group*) and included in Annexure 1 and Annexure 2 of this Prospectus, but may also include certain other assumptions and analyses.

Petroleum hydrocarbons data

Unless expressly stated otherwise, all estimates of proved and probable reserves and related future net revenue and contingent and prospective resources disclosed in this Prospectus have been prepared in accordance with the PRMS. These standards of reporting may be different from those adopted in the United States and other jurisdictions. Investors, therefore, should not assume that the data found in the reserves and resources information set forth in this Prospectus is directly comparable to similar information that has been prepared in accordance with the reserve and resource reporting standards of other jurisdictions. As presented in the PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Unless otherwise noted, reserves estimates are presented on a "*company gross*" basis, representing the Group's working interest share before deduction of royalties.

The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgement. This Prospectus should be accepted with the understanding that reserves, resources and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

Currencies

In this Prospectus, references to "**GBP**" or "**£**" are to the lawful currency of the UK, references to "**AUD**" or "**A$**" are to the lawful currency of Australia, and references to "**U.S. dollars**", "**USD**" or "**US$**" are to the lawful currency of the United States. The functional and presentation currency of Woodside and all its subsidiaries is U.S. dollars. Transactions in foreign currencies are initially recorded in the functional currency of the transacting entity at the exchange rates ruling at the date of transaction. Monetary assets and liabilities denominated in foreign currencies at the reporting date are translated at the rates of exchange ruling at that date. Exchange differences in the consolidated financial statements are taken to the income statement.

Rounding

Percentages and certain amounts in this Prospectus, including financial, statistical and operating information, have been rounded to the nearest thousand whole number or single decimal place for ease of presentation. As a result, the figures shown as totals may not be the precise sum of the figures that precede them. In addition, certain percentages and amounts contained in this Prospectus reflect calculations based on the underlying information prior to rounding, and, accordingly, may not conform exactly to the percentages or amounts that would be derived if the relevant calculations were based upon the rounded numbers.

Third-party information

Woodside confirms that all third-party information contained in this Prospectus has been accurately reproduced and, so far as Woodside is aware and is able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where third party information has been used in this Prospectus, the source of such information has also been identified.

Statements regarding the oil and gas industry which are not based on published statistical data or information obtained from independent third parties, are based on the Group's and/or the Directors' experience, the Group's internal studies and estimates, and the Group's own investigation of market conditions. Woodside cannot assure prospective investors that any of these studies or estimates are accurate, and none of the Group's internal surveys or information has been verified by any independent sources. While the Directors are not aware of any misstatements regarding the Group's own estimates presented herein, those estimates involve risks, assumptions and uncertainties and are subject to change based on various factors, including those set out in Part 2 (*Risk Factors*) of this Prospectus.

Forward-looking statements and forecasts

This Prospectus contains "*forward-looking statements*" and "*forward-looking information*" that are based on Woodside's expectations, estimates and projections as of the date on which the statements were made. This forward-looking information includes, among other things, statements with respect to the Competent Person's Report, Woodside's business strategy with respect to the projects, plan, development, objectives, performance, outlook, growth, cash flow, projections, targets and expectations, oil and gas reserves and resources, results of exploration, the price and demand for oil and gas and acts by Woodside's partners to the respective projects.

Generally, this forward-looking information can be identified by the use of forward-looking terminology such as "*outlook", "anticipate", "project", "target", "likely", "believe", "estimate", "expect", "intend", "may", "would", "could", "should", "scheduled", "will", "plan", "forecast", "evolve"* and similar expressions. Persons reading this Prospectus are cautioned that such statements are only predictions, and that Woodside's actual future results or performance may be materially different.

Forward-looking information is subject to known and unknown risks, uncertainties and other factors that may cause Woodside's actual results, level of activity, performance or achievements to be materially different from those expressed or implied by such forward-looking information. These statements speak only as of the date of this Prospectus and do not seek in any way to qualify the working capital statement given by Woodside at paragraph 20 of Part 21 (*Additional Information*) of this Prospectus. Actual operational and financial results or events may differ materially from Woodside's expectations contained in the forward-looking statements as a result of various factors, many of which are beyond the control of Woodside.

Statements related to reserves or resources are deemed to be forward-looking information as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and prospective resources can be profitably produced in the future. The forward-looking statements contained in this Prospectus are expressly qualified by this cautionary statement. Woodside does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

Forward-looking statements involve significant known and unknown risks and uncertainties. Exploration, appraisal, and development of oil and natural gas reserves are speculative activities and involve a significant degree of risk. Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although Woodside believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Woodside can give no assurance that such expectations will prove to be correct.

Investors are cautioned that forward-looking statements are not guarantees of future performance. Woodside makes no representation, warranty or prediction that the results predicted by such forward-looking statements will be achieved and these forward-looking statements represent, in each case, only one of many possible scenarios and should not be viewed as the most likely or standard scenario. Forward-looking statements may, and often do, differ materially from actual results. Any forward-looking statements in this Prospectus speak only as at the date of this Prospectus, reflect the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the Group's operations, results of operations, growth strategy and the availability of new credit. Investors should specifically consider the factors identified in this Prospectus that could cause actual results to differ. All of the forward-looking statements made in this Prospectus are qualified by these cautionary statements.

No statement in this Prospectus is intended as a profit forecast or estimate and no statement in this Prospectus should be interpreted to mean that earnings per share for the most recent, current or future financial years would necessarily match or exceed the historical published earnings per share.

Subject to the requirements of the Prospectus Regulation Rules, the DTR and the LSE Listing Rules, or applicable law, Woodside explicitly disclaims any intention or obligation or undertaking publicly to release the result of any revisions to any forward-looking statements in this Prospectus that may occur due to any change in the Group's expectations or to reflect events or circumstances after the date of it.

Basis of presentation of Competent Person's Report

The Competent Person's Report has been prepared in accordance with the PRMS. The Competent Person's Report is compliant with the Competent Person's Report requirements as published in the ESMA update of the Committee of European Securities Regulators' recommendations of the European Commission Regulation on Prospectuses No. 809/2004 dated 20 March 2013 (ESMA/2013/319).

In preparation of the Competent Person's Report, Gaffney, Cline & Associates Limited relied upon, without independent verification, information furnished by, or on behalf of, Woodside with respect to the property interests being evaluated, production from such properties, current cost of operations and development, current prices for production, agreements related to current and future operations and sale of production, estimation of taxes, and various other information and data that were accepted as represented.

No incorporation of website

The contents of Woodside's website, any website mentioned in this Prospectus or any website directly or indirectly linked to these websites have not been verified and do not form part of this Prospectus and investors should not rely on such information.

Definitions and technical terms

A list of defined terms used in this Prospectus is set out in Part 22 (*Definitions and Glossary*) of this Prospectus. A list of defined technical terms and conversions used in this Prospectus is set out in Part 23 (*Glossary of Technical Terms*) of this Prospectus.

Part 4 – Consequences of a Standard Listing

Listing Rules

In addition to Woodside's primary listing on ASX and its application for a secondary listing of the Woodside ADSs to listing and trading on NYSE, an application will be made for all of the Woodside Shares to be admitted to listing on the standard segment of the Official List pursuant to Chapter 14 of the LSE Listing Rules, which sets out the requirements for Standard Listings and does not require Woodside to comply with among other things, the provisions of Chapters 6 to 13 of the LSE Listing Rules (excluding Listing Principles 1 and 2). As a result, Woodside's securities will not be eligible for inclusion in the UK series of the FTSE indices. There are, however, a number of principles and continuing obligations set out in Chapter 7 and Chapter 14, respectively, of the LSE Listing Rules that will be applicable to Woodside.

Disclosure Guidance and Transparency Rules

Under Rule 5 of the DTR (Vote Holder and Issuer Notification Rules) ("**DTR5**"), a person must notify Woodside and the FCA of the percentage of Woodside's voting rights he or she holds as a Shareholder (or holds or is deemed to hold through his or her direct or indirect holding of financial instruments) if, as a result of an acquisition or disposal of Woodside Shares or financial instruments, or as a result of any event changing the breakdown of voting rights of Woodside (for example, a buy-back of Woodside Shares by Woodside), the percentage of those voting rights in which he or she is interested reaches, exceeds or falls below 5%, 10%, 15%, 20%, 25%, 30%, 50% and 75%.

Notification must be made to the FCA no later than four trading days after the date upon which the person making the notification (1) learns of the acquisition or disposal or of the possibility of exercising voting rights, or on which, having regards to the circumstances, should have learned of it, regardless of the date on which the acquisition, disposal or possibility of exercising voting rights takes effect, or (2) is informed about the event changing the breakdown of voting rights of Woodside.

Any person who is in breach of their obligations under DTR5 is liable to a fine and/or public censure by the FCA and the FCA may apply to court to have such person's voting rights suspended.

Additional ASX and NYSE listing requirements

Following Admission, in addition to complying with the requirements of being listed on the standard segment of the Official List, Woodside will comply with the requirements of having its primary listing on the ASX together with the applicable requirements resulting from the Woodside ADSs being admitted to listing and trading on the NYSE.

Part 5 – Expected Timetable of Principal Events

Announcement of the Merger and execution of the Merger Commitment Deed	17 August 2021
Execution of the binding Share Sale Agreement to Implement the Merger	22 November 2021
Publication of this Prospectus	11 April 2022
Woodside Shareholders' Meeting to approve the Merger	19 May 2022
Implementation of the Merger	1 June 2022
Distribution Record Date for the Merger	26 May 2022
Admission and commencement of dealings in Woodside Shares on the LSE	8.00 am on 6 June 2022
Despatch of CSN Facility holding statements in respect of Woodside Shares	By no later than 16 June 2022
Expected date for receipt of sale proceeds by Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders	By no later than 24 August 2022

Future dates and times are indicative only and may be subject to change without notice or consultation. The times referred to above are references to the time in London.

Part 6 – Admission Statistics and Dealing Codes

Expected number of Woodside Shares in issue on Admission	1,898,749,771
Expected number of Woodside Shares under performance rights or employee share options outstanding at Admission	7,489,385
Expected number of Woodside Shares on a fully diluted basis on Admission	1,906,239,156
Expected percentage of issued share capital represented by performance rights or employee share options outstanding at Admission	0.4%
Expected market capitalisation of Woodside on Admission	A$63,038,492,397
ISIN[6]	AU000000WPL2
LEI	2549005ZC5RXAOO7FH41
SEDOL	BN0WKS4
Expected tickers on Admission	ASX: WDS LSE: WDS NYSE: WDS

6 The ISIN is expected to change prior to Admission following Woodside's proposed change of name.

Part 7 – Overview of Woodside

1 Overview

Woodside is an ASX listed oil and gas company based in Perth, Western Australia. As an Australian leading LNG operator, Woodside operated 5% of global LNG supply in 2021. Woodside operates the majority of its assets and has over 65 years of experience in the oil and gas industry. Woodside's producing portfolio is primarily centred around the production of LNG from conventional offshore projects in Western Australia and also includes oil, condensate, LPG, and domestic gas for Western Australian customers.

2 Important events

The important events in the development of the business are noted below:

- 1954 – Incorporated as Woodside (Lakes Entrance) Oil Co.
- 1962-63 – Granted exploration permits off North West Shelf of Western Australia.
- 1968 – First oil discovery at the Legendre field on the North West Shelf.
- 1971-74 – Major gas and condensate discoveries at Scott Reef, North Rankin, Angel, Goodwyn, Sunrise and Troubadour.
- 1977 – Agreement announced on key terms and conditions of NWS Project.
- 1980 – Construction starts on Karratha Gas Plant, North Rankin A platform and 135km pipeline to shore.
- 1984 – First gas received onshore via the subsea trunkline from the North Rankin platform.
- 1989 – First LNG cargo from NWS Project delivered to Japan.
- 2000 – Laverda oil field, offshore Exmouth discovered.
- 2005 – Pluto gas field, offshore Karratha discovered.
- 2006 – First LNG cargo from NWS delivered to China.
- 2012 – Pluto LNG Plant begins LNG production, and first Pluto LNG cargo is delivered to Japan.
- 2013 – North Rankin Complex completed.
- 2015-16 – Acquisition of interests in Wheatstone, Scarborough and Sangomar.
- 2017 – Production commenced at Wheatstone (Woodside as non-operator of the downstream).
- 2020 – Sangomar Field Development Phase 1 achieved final investment decision.
- 2021 – Announced all-stock merger of Woodside and BHP's petroleum business.
- 2021 – Scarborough and Pluto Train 2 development achieved final investment decision.

3 Business overview

Woodside's operated LNG projects include two integrated projects, the NWS Project, Australia's largest LNG project, and Pluto LNG. In 2020, Woodside's operating performance was demonstrated by the reduction in production costs down to their lowest level in 5 years at US$4.8/boe while achieving LNG reliability of 97.6%.

Offshore, Woodside operates two floating production storage and offloading ("**FPSO**") facilities, the Okha FPSO and Ngujima-Yin FPSO. Woodside also has a participating interest in Wheatstone LNG, which started production in 2017 and is the upstream operator of Julimar-Brunello, one of the Wheatstone LNG feeder fields.

In addition to its producing assets, Woodside is progressing the development of the Scarborough gas resource through new offshore facilities to a second LNG train (Pluto Train 2) at the existing Pluto LNG onshore facility in Western Australia. Woodside is also connecting Pluto LNG with the North West Shelf Project through the Pluto-KGP Interconnector to create an integrated LNG production hub on the Burrup Peninsula. Refer to Part 17 (*Operating and Financial Review of Woodside*) of this Prospectus for Woodside's recent historic and ongoing principal capital expenditures and divestitures.

Internationally, Woodside is executing the Sangomar Field Development Phase 1 in Senegal, having achieved final investment decision in January 2020. This development is targeting first oil in 2023.

The below table provides a breakdown of Woodside's total revenues by producing operating segment:

Year end, 31 Dec US$m	North West Shelf			Pluto			Australia Oil			Wheatstone		
	2021	2020	2019	2021	2020	2019	2021	2020	2019	2021	2020	2019
Liquefied natural gas	1,209	722	1,102	2,415	1,320	1,753	-	-	-	581	365	572
Domestic gas	8	44	69	19	11	4	-	-	-	16	18	10
Condensate	253	194	271	215	114	188	-	-	-	175	103	127
Oil	-	-	-	-	-	-	673	432	360	-	-	-
Liquefied petroleum gas	60	16	44	-	-	-	-	-	-	-	-	-
Other revenue	-	-	-	145	142	119	-	-	-	-	-	-
Operating revenue from contracts with customers	**1,530**	**976**	**1,486**	**2,794**	**1,587**	**2,064**	**673**	**432**	**360**	**772**	**486**	**709**

4 Assets

4.1 Overview of Assets

Woodside's portfolio is centred around large-scale integrated LNG projects which are supplied by conventional offshore Western Australia fields. These projects also supply condensate and LPG to Australian and international markets and domestic gas to Western Australia. Woodside is the Operator of all its key producing assets, apart from Wheatstone LNG, where it is operator of Julimar Brunello, one of the Wheatstone LNG feeder fields. Woodside's key projects in execution are Scarborough and Pluto 2 development, which is a new LNG development through an expansion at the Pluto LNG facility in Western Australia, and the Sangomar Field Development Phase 1 in Senegal. Woodside holds further gas resources as future development opportunities.

Producing Assets

Asset	Description	Operator	Woodside ownership	2021 Production[7] MMboe
Pluto LNG	LNG facility processing gas from the subsea offshore Pluto, Xena and Pyxis gas fields in Western Australia. Gas is piped from the offshore Pluto-A platform to a 4.9 Mtpa LNG processing train.	Woodside	90%	44.3
North West Shelf Project	LNG facility processing gas and condensate from the offshore North Rankin and Goodwyn-A offshore platforms and subsea tiebacks. Onshore facilities include 5 LNG trains with 16.9 Mtpa LNG export capacity, condensate trains and a domestic gas plant.	Woodside	16.67%	24.7
Wheatstone	8.9 Mtpa LNG facility processing gas from the offshore Wheatstone, Iago, Julimar and Brunello gas fields. The onshore plant consists of two LNG trains, a domestic gas plant and associated infrastructure.	Chevron	Wheatstone LNG: 13% Julimar Brunello: 65%	13.5
Australia Oil	Two stand-alone oil developments offshore Western Australia, comprising the Nguyjima-Yin FPSO and Okha FPSO.	Woodside	Various	8.6

7 Production numbers reflect Woodside's percentage share of the production of the Asset.

Project and Growth Options

Asset	Description	Operator	Woodside ownership	FID/Target FID	Target first production
Key projects					
Scarborough/ Pluto Train 2	The development of the 11.1 Tcf (100%) Scarborough offshore gas resource comprises a new floating production facility, trunkline to shore and expansion of the existing Pluto LNG onshore facility (including construction of Pluto Train 2).	Woodside	Scarborough 73.5% Pluto Train 2 51%[8]	FID announced 22 November 2021	2026 (first cargo)
Sangomar	Senegal's first oil development comprises a stand-alone FPSO and subsea infrastructure, located approximately 100km south of Dakar. FID was taken in 2020 and first oil is targeted for 2023.	Woodside	82%	Jan 2020	2023
Browse	Located in the offshore Browse Basin, approximately 425km north of Broome in Western Australia, comprising the Brecknock, Calliance and Torosa fields.	Woodside	30.6%		
Sunrise	Comprises the Sunrise and Troubadour gas and condensate fields, collectively known as Greater Sunrise, located between Australia and Timor-Leste.	Woodside	33.44%		
Liard Basin	Upstream gas resource in British Columbia, Canada, provides an option to investigate potential future natural gas, ammonia and hydrogen opportunities.	Chevron	42.5%-100%		

4.2 Producing Assets

1. Pluto LNG

Pluto LNG overview and history

Pluto LNG processes gas from six subsea wells on the offshore Pluto, Xena and Pyxis gas fields in Western Australia. Natural gas and condensate are piped through a 180km trunkline to a single onshore facility, located between the NWS Project and the Dampier Port on the Burrup Peninsula. The offshore infrastructure includes the Pluto-A Offshore Platform, located 180km north-west of Karratha in 85 metres of water.

[8] On 18 January 2022, Woodside completed the sale of 49% in Pluto Train 2 joint venture to Global Infrastructure Partners. The transaction had an effective date of 1 October 2021. Following completion of the sale to GIP, Woodside holds a 51% participating interest in the Pluto Train 2 Joint Venture and remains as operator.

The onshore infrastructure currently comprises a single LNG processing train (Pluto Train 1) and has an average annualised capacity of 4.9 Mtpa. The facility has been producing above nameplate capacity (~15% higher than the 4.3 Mtpa at start-up in 2012) due to LNG capacity improvements through process optimisation and equipment upgrades utilising new technology. Pluto LNG also produces condensate and domestic gas.

Pluto LNG is one of the world's most technologically advanced LNG production facilities, with the Pluto gas field discovered by Woodside in 2005 and achieving first production seven years later. The project has delivered more than 500 cargoes.

In order to process Scarborough gas, Woodside is undertaking an expansion of the Pluto LNG facility in Western Australia through the construction of a second gas processing train, Pluto Train 2, which would have a capacity of 5.0 Mtpa. Woodside announced on 22 November 2021 that final investment decisions have been made in relation to the Scarborough and Pluto Train 2 developments. Refer to paragraph 7.1 of Part 7 (*Overview of Woodside)* for further detail. The Scarborough and Pluto Train 2 developments also include the processing of 2.0 – 3.0 Mtpa LNG at Pluto Train 1 as well as utilising the already built common facilities, which will require modifications to accommodate the Scarborough gas.

Woodside is also currently constructing the Pluto–KGP Interconnector, a pipeline connecting Pluto LNG and the North West Shelf's Karratha Gas Plant ("**KGP**"). The infrastructure will allow the transfer of gas between the plants to optimise production across both facilities and enable future development of additional gas reserves. Refer to paragraph 7.2 of Part 7 (*Overview of Woodside)* for further detail on the Pluto-KGP Interconnector.

Ownership structure and joint ventures

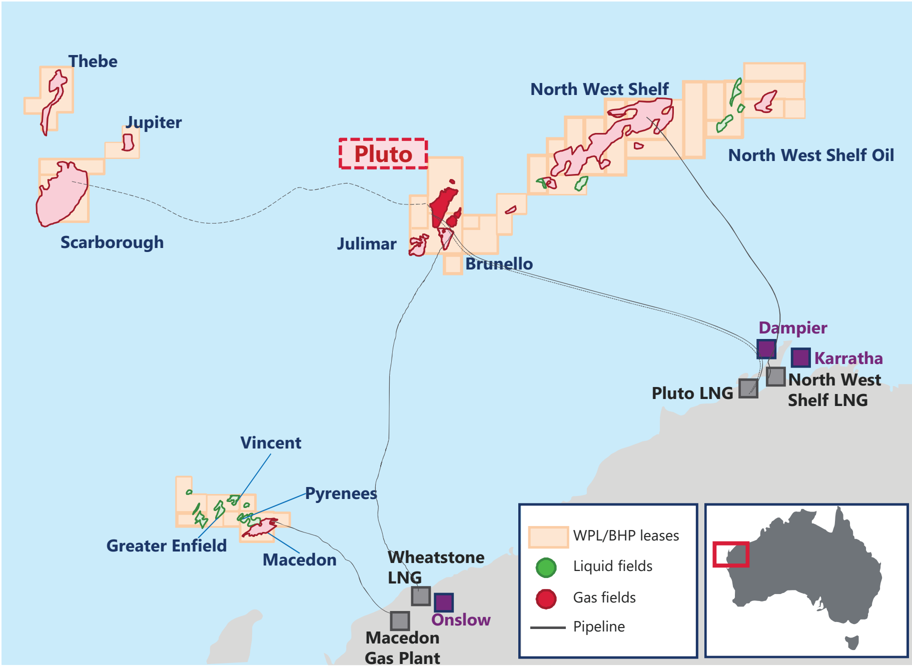
The Pluto fields lies within permit WA-34-L. Woodside operates and has a 90% participating interest in the Pluto LNG joint venture. The other Pluto joint venture participants are Tokyo Gas Co. Ltd. and Kansai Electric Power Company Incorporated, who each own 5% of the project and are also the key long-term LNG off-takers in the project. Woodside is the sole holder of exploration permit WA-404-P, and any commercial discoveries made in this permit are intended to be tied back to Pluto LNG.

Growth opportunities

Woodside is developing additional offshore resources and improvements to the onshore Pluto LNG facility. The Pyxis Hub Project comprises the subsea tie-back of the Pyxis, Pluto North and Xena fields to the Pluto offshore platform. Woodside has commenced installation of subsea equipment and is preparing for cold commissioning and start-up for the initial wells.

The Pluto water handling project was successfully installed on the Pluto offshore platform in late-2020. Once commissioned, the module will allow increased wet gas production. Hook-up and commissioning activities are continuing in 2021.

Figure 1 – Pluto Project map[9]



Onshore infrastructure

Pluto LNG Plant	
Location	1,260km north of Perth, WA
Facility type	Onshore gas plant
Facility features	1 LNG processing train, 1 domestic gas offtake point, 2 condensate stabilisation units, 1 domestic LNG truck loading facility
Product	LNG (both domestic and export), condensate, pipeline gas
First production	2012
Capacity	LNG: 4.9 Mtpa Domestic gas: 25 TJ/d Condensate: 1,140 tonnes/d

Offshore infrastructure

Pluto Platform	
Location	190km north-west of Karratha, WA
Facility type	Steel jacket fixed platform
Fields (discovered (approximate))	Pluto (2005), Xena (2006), Pyxis (2015)
Product	Gas and condensate
Production capacity	Raw gas: 1,320 MMscf/d
First production	2012
Platform water depth	85m
Subsea and pipelines	Trunkline 1 to shore

[9] Fields, blocks and pipelines shown in maps are stylised and not to scale. These maps are intended to show the general location and proximity of Woodside and BHP Petroleum's Carnarvon Basin assets. Map only shows the key Woodside and BHP Petroleum fields, leases and pipelines which are referenced in the Woodside and BHP Petroleum Overview Parts of this Prospectus.

2. North West Shelf Project

North West Shelf Project overview and history

The North West Shelf project ("**NWS Project**") consists of several offshore conventional gas and condensate fields in the Carnarvon Basin off the Pilbara coast of Western Australia and associated offshore and onshore infrastructure.

The NWS Project was formed in the 1960s and the first deliveries of gas were made to Perth via the Dampier to Bunbury Natural Gas Pipeline in 1984. The first LNG cargo was delivered to Japan in 1989 and the project has delivered in excess of 5,500 cargoes.

The North West Shelf production infrastructure consists of four offshore platforms; the North Rankin Complex ("**NRC**") which comprises the North Rankin A and North Rankin B platforms, Goodwyn A Platform and the Angel Platform. The offshore infrastructure also includes the subsea tiebacks of Greater West Flank and Perseus over Goodwyn to Goodwyn A and Persephone to NRC. Gas from these platforms is transported from the North Rankin Complex by two 135km subsea trunklines onshore to the KGP on the Burrup Peninsula.

KGP is an advanced integrated gas production system, producing LNG, domestic gas, condensate and LPG. The facility is located 1,260km north of Perth, Western Australia and covers approximately 200 hectares. KGP has an LNG export capacity of 16.9 Mtpa, with five LNG processing trains, two domestic gas trains, five condensate stabilisation units and three LPG fractionation units.

The NWS Project infrastructure provides an opportunity for processing third-party gas as the NWS reserves decline. In July 2020, NWS Project participants executed amendments to the joint venture governance documents which enable the processing of third-party gas through the NWS Project facilities.

In further support of processing gas supplied by other resource owners, the NWS Project participants executed fully termed gas processing agreements ("**GPAs**") in December 2020 for processing third-party gas through the NWS project facilities. GPAs were signed with Woodside Burrup Pty Ltd, in respect of gas from the Pluto fields, and with subsidiaries of Mitsui & Co Ltd and Beach Energy Limited, in respect of gas from the Waitsia Gas Project Stage 2. Execution of the GPAs is an important milestone in establishing NWS as a tolling facility and is expected to unlock further value for the NWS Project participants.

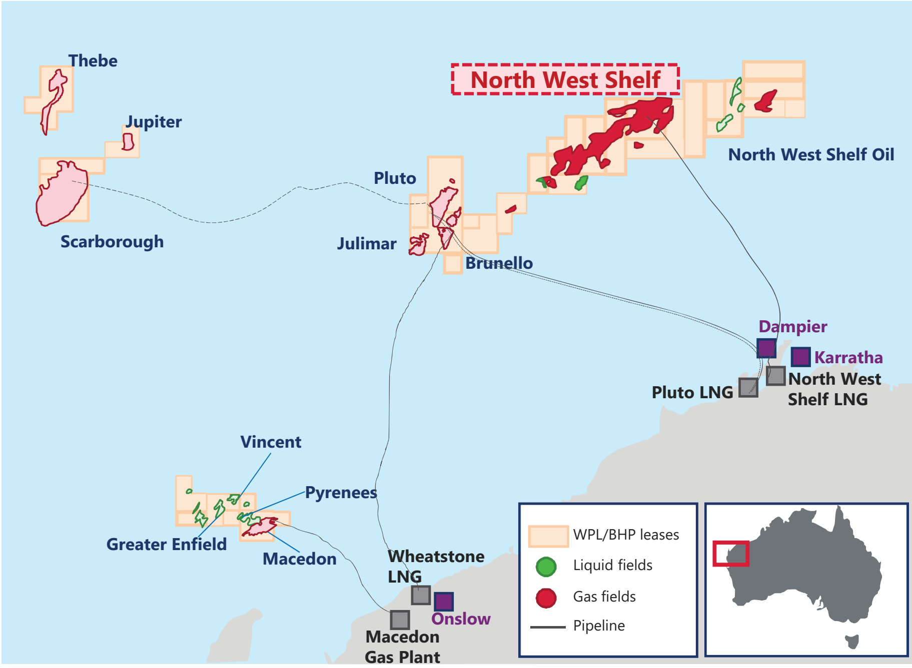
In December 2020, the NWS Project participants took a final investment decision for the infrastructure required to receive gas from the Pluto-KGP Interconnector. Refer to paragraph 7.2 of Part 7 (*Overview of Woodside)* for further detail on the Pluto-KGP Interconnector. The NWS Project participants are currently in the process of planning restoration of the no longer producing Echo-Yodel and Angel subsea wells and associated subsea infrastructure.

Ownership structure and joint ventures

The North West Shelf fields lie within permits WA-1-L, WA-23-L, WA-24-L, WA-3-L, WA-30-L, WA-5-L, WA-6-L, WA-7-R, WA-57-L, WA-58-L, WA-56-L, WA-2-L WA-28-P, WA-4-L, WA-9-L, WA-16-L, WA-52-L, WA-53-L, and WA-11-L. Ownership of the NWS Project and the associated production is split between several joint ventures with different participating interests. Woodside owns a one-sixth participating interest in the original NWS LNG joint venture, which was responsible for all LNG production and sale at the NWS Project. Other NWS LNG joint venture participants, which also own one-sixth stakes, include BHP Petroleum, BP plc ("**BP**"), Chevron, Shell and MIMI. CNOOC also has a participating interest in the NWS Project through the joint venture that is responsible for supplying LNG to the Guangdong Dapeng LNG Project in China (Woodside participating interest: 12.5%). There are other joint ventures within the NWS Project, which are responsible for Western Australian domestic gas production (Woodside participating interest: 15.78%) and production of additional "equity lifted" (the proportion of LNG which Woodside is entitled to lift and sell, in its own right, as a result of its participating interest in the relevant project) LNG above joint contract quantities (Woodside participating interest: 15.78%).

Dedicated LNG facilities, such as the gas treatment and liquefaction trains, and LNG storage tanks, are owned on an equal one-sixth basis by six of the seven NWS Project participants (excluding CNOOC). All other assets, which are used in both the domestic gas and LNG processing activities, are owned in varying percentages (excluding CNOOC) based on their interests in the above joint ventures. Six of the seven NWS Project participants (excluding CNOOC) also separately own an equal share in ships that they utilise for the Project.

Figure 2 – North West Shelf Project map[10]



Principal producing fields

The principal fields in the North West Shelf are Goodwyn, North Rankin, Perseus and fields within the Greater Western Flank area. This group of fields is located approximately 135km offshore of northwest Australia in water depths ranging between 80m and 130m. These fields are primarily natural gas fields, with the exception of Cossack Wanaea Lambert Hermes, which are predominantly oil fields (covered in paragraph 3 of Part 9 *(Industry Overview)*. Total acreage for all permits/licence areas covered by the NWS Project is 3,790km^2.

Onshore infrastructure

Karratha Gas Plant	
Location	1,260km north of Perth, WA
Facility type	Onshore gas plant
Facility features	5 LNG processing trains, 2 domestic gas trains, 5 condensate stabilisation units, 3 LPG fractionation units
Product	LNG, pipeline natural gas, condensate and LPG
First Production	1984
Capacity	LNG: 16.9 Mtpa Domestic gas: 630 TJ/d Condensate: 14,385 tonnes/d

[10] Fields, blocks and pipelines shown in maps are stylised and not to scale. These maps are intended to show the general location and proximity of Woodside and BHP's Petroleum's Carnarvon Basin assets. Maps only shows the key Woodside and BHP Petroleum fields, leases and pipelines which are referenced in the Woodside and BHP Petroleum Overview Parts of this Prospectus.

Offshore infrastructure

	North Rankin Complex	Goodwyn A Platform	Angel Platform
Location	135km north-west of Karratha, Western Australia	23km south-west of the North Rankin A platform, 135km north-west of Karratha, Western Australia	120km north-west of Karratha, Western Australia, connected to the NRC via 50km subsea pipeline
Facility type	Steel jacket fixed platform	Steel jacket fixed platform	Steel jacket fixed platform
Fields (discovered (approximate))	North Rankin (1971), Perseus (1996)	Goodwyn (1972), Echo (1988), Yodel (1990), Perseus (1996)	Angel (1971)
Product	Gas and condensate	Gas and condensate	Gas and condensate
Production capacity	Dry gas: 60,000 tonnes/d Condensate: 6,200 tonnes/d	Dry gas: 38,000 tonnes/d Condensate: 18,000 tonnes/d	Dry gas: 21,500 tonnes/d Condensate: 5,270 tonnes/d
First production	1984 (NR-A) and 2013 (NR-B)	1995	2008
Platform water depth	125m	131m	80m
Subsea and pipelines	Trunklines 1 and 2 to shore	Interfield Line to Trunkline 2	Interfield Line to Trunkline 1

3. Wheatstone

Wheatstone overview and history

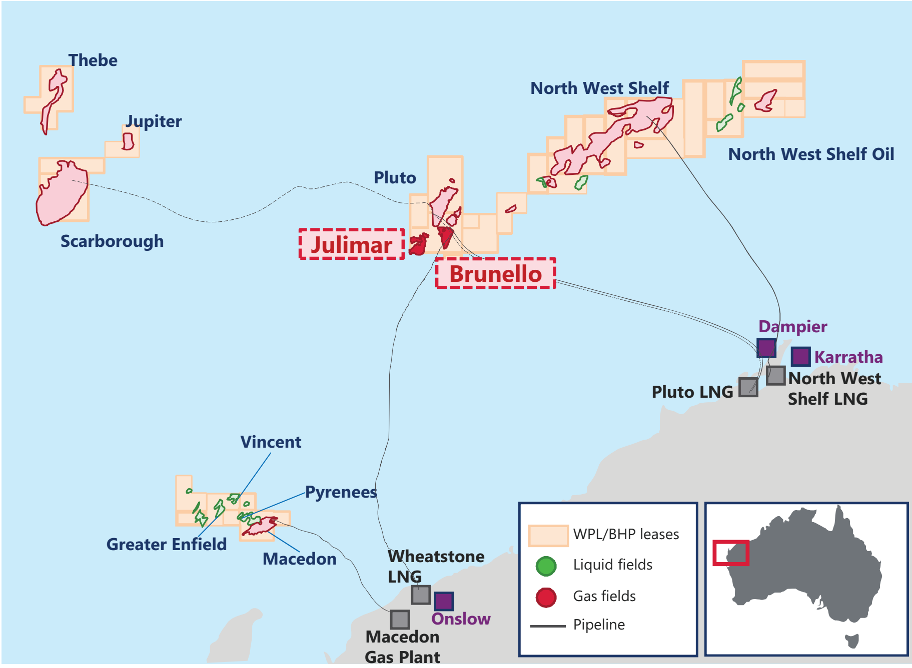
Wheatstone is located in the offshore North Carnarvon Basin off the Pilbara coast of Western Australia. The project consists of an offshore platform located 220km from Onslow, Western Australia, connected by a trunkline to an onshore plant consisting of two LNG trains (8.9 Mtpa capacity), a domestic gas plant (200 TJ/d capacity) and associated infrastructure. Feed gas to the LNG train is supplied by the Chevron-operated Wheatstone and Iago fields and the Woodside-operated Julimar and Brunello fields. The Wheatstone Project also produces condensate and domestic gas.

Production from Train 1 commenced in 2017, Onshore LNG Train 2 successfully commenced production in June 2018 and domestic gas production supply commenced on 5 March 2019. Since production started over 500 LNG cargoes have been lifted for a total of ~79 million cubic metres of LNG produced, and over 65 condensate cargoes have been lifted for a total of 6.8 million cubic metres of condensate produced as at 31 December 2021.

Ownership structure and joint venture

Chevron Australia Pty Ltd is the operator of the Wheatstone Project (64.14%). Woodside has a 13.0% participating interest, while the other joint venture participants are KUFPEC (13.4% participating interest), PE Wheatstone Pty Ltd (8.0% participating interest, a Japanese consortium) and Kyushu Electric Wheatstone Pty Ltd (1.46% participating interest). Woodside's 13.00% participating interest in the Wheatstone Project includes the offshore platform, the pipeline to shore and the onshore plant, but excludes the Wheatstone and Iago fields and associated subsea infrastructure. Woodside also has a 65% operating interest in the Julimar Brunello Project and associated subsea infrastructure, with the remaining 35% owned by KUFPEC. The Julimar and Brunello fields lie within permit WA-49-L.

Figure 3 – Wheatstone Project map[11]



Onshore infrastructure

Wheatstone LNG Plant	
Location	12km west of Onslow on the Pilbara coast of Western Australia
Facility type	Onshore gas plant
Facility features	2 LNG processing train, 1 domestic gas train, 2 condensate stabilisation units
Product	LNG, condensate, domestic gas
First production	2017
Capacity	LNG: 8.9 Mtpa Domestic gas: 200 TJ/d Condensate: 8,661 sm3/d

Offshore infrastructure

Wheatstone Offshore Platform	
Location	220km from Onslow, WA
Facility type	Offshore steel gravity structure platform
Fields (discovered (approximate))	Wheatstone (2004), Iago (2004), Julimar (2007), Brunello (2007)
Product	LNG, pipeline natural gas and condensate
Production capacity	Dry gas: 1,970 MMscf/d Condensate: 8,600 sm3/d
First production	2017
Platform water depth	73m
Subsea and pipelines	Woodside operated Julimar Brunello subsea development to Wheatstone offshore platform. Chevron operated Wheatstone Iago subsea development to Wheatstone offshore platform. Trunkline 1 to shore

11 Fields, blocks and pipelines shown in maps are stylised and not to scale. These maps are intended to show the general location and proximity of Woodside and BHP's Petroleum's Carnarvon Basin assets. Maps only shows the key Woodside and BHP Petroleum fields, leases and pipelines which are referenced in the Woodside and BHP Petroleum Overview Parts of this Prospectus.

4. Australia Oil

Australia Oil overview and history

Woodside's Australia Oil operations consists of two facilities, Ohka FPSO and Ngujima-Yin FPSO, and their associated fields off the coast of Western Australia and are principally engaged in extracting oil.

Okha's Cossack, Wanaea, Lambert and Hermes fields are located approximately 135km north-west of Karratha, off the north-west coast of Western Australia. All fields lie on the inner continental shelf in water depths of 75 to 135m. Okha has 13 wells, 10 able to flow and 5 currently flowing. The Wanaea and Cossack fields also pipe a stream of LPG-rich gas via North Rankin to the KGP for processing. Though also located on the North West Shelf, the Okha FPSO is reported as its own entity by Woodside.

The Ngujima-Yin FPSO processes crude oil from the Vincent and Greater Enfield oil fields. The development consists of 13 Vincent oil wells, 6 Greater Enfield oil wells, 1 gas injector and back producer, 2 Vincent water injection wells and 6 customised water flood wells.

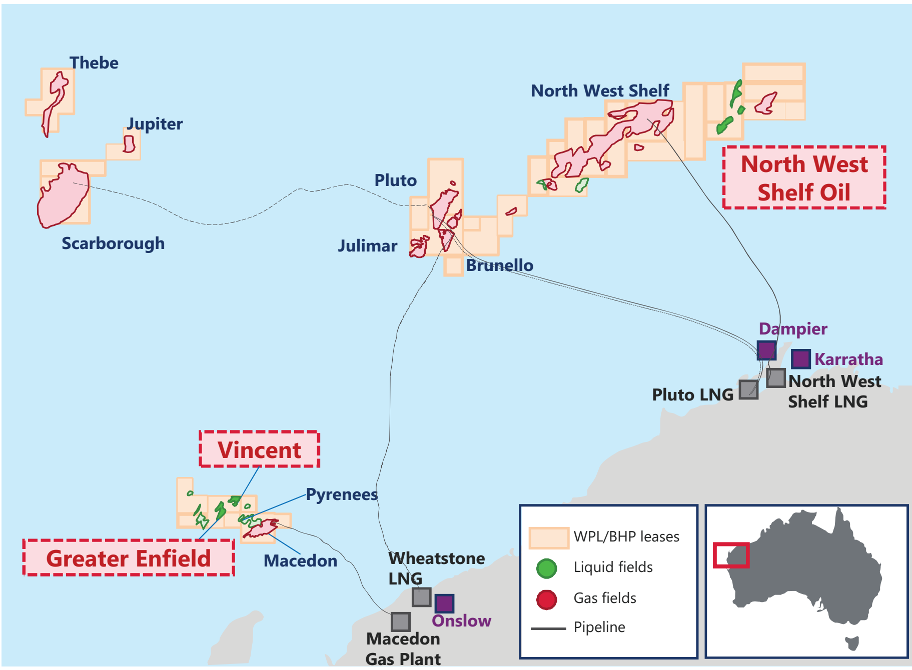
Woodside is currently in the process of planning restoration including the plugging and abandonment of the no longer producing Enfield and Balnaves oil fields. Stybarrow is operated by BHP, and Woodside continues to support the planning for decommissioning in accordance with the joint venture agreement.

Ownership structure and joint ventures

The Ngujima-Yin FPSO fields lie within permits WA-59-L and WA-28-L. The joint venture is owned by Woodside (60.0%, operator) and Mitsui (40.0%).

The Okha FPSO fields lies within permits WA-11-L, WA-9-L and WA-16-L. The joint venture is owned by Woodside (33.33%) with BHP Petroleum, BP, Chevron, and MIMI, each having a 16.67% participating interest.

Figure 4 – Australia Oil Project map[12]



[12] Fields, blocks and pipelines shown in maps are stylised and not to scale. These maps are intended to show the general location and proximity of Woodside and BHP's Petroleum's Carnarvon Basin assets. Map only shows the key Woodside and BHP Petroleum fields, leases and pipelines which are referenced in the Woodside and BHP Petroleum Overview Parts of this Prospectus.

Offshore infrastructure

	Ngujima-Yin FPSO	Okha FPSO
Location	50km northwest of Exmouth, Western Australia	34km east of the North Rankin Complex
Facility type	Floating production storage and offloading facility	Floating production storage and offloading facility
Fields (discovered (approximate))	Vincent (1998), Laverda Field (2000), Cimatti Field (2010), Norton Over Laverda (2011)	Wanaea (1989), Cossack (1990), Lambert (1973), Hermes (1996)
Product	Oil	Oil and gas
Production capacity	Oil: 120 kbbl/d	Oil: 60 kbbl/d Gas: 82 MMscf/d
First production	2008	1995
Facility water depth	350m	80m

5 Description of Property

Woodside's head office building, located in Western Australia at Mia Yellagonga, 11 Mount Street, Perth, is leased.

All of the Woodside interests in the properties described below are owned by Woodside or another member of the Woodside Group.

Asset	Location	Woodside interest (%)	100% capacity	Woodside operated
Pluto LNG	Offshore and onshore Western Australia	90%	Pluto Platform: 1,320 MMscf/d raw gas Pluto LNG: 4.9 Mtpa LNG, 25 TJ/d domestic gas, 1,140 tonnes/d condensate	Yes
North West Shelf LNG	Offshore and onshore Western Australia	16.67% of original LNG JV 12.5% of China LNG JV 15.78% of Extended Interest Joint Venture	North Rankin Complex: 60,000 tonnes/d dry gas, 6,200 tonnes/d condensate Goodwyn A platform: 38,000 tonnes/d dry gas, 18,000 tonnes/d condensate Angel platform: 21,5000 tonnes/d dry gas, 5,270 tonnes/d condensate Karratha Gas Plant: 16.9 Mtpa LNG, 630, TJ/d domestic gas, 14,385 tonnes/d condensate	Yes
Wheatstone LNG	Offshore and onshore Western Australia	13.0% of Wheatstone LNG 65.0% of Julimar-Brunello	Wheatstone offshore platform: 1,970 MMscf/d dry gas, 8,600 Sm3/d condensate Wheatstone LNG: 8.9 Mtpa LNG, 200, TJ/d domestic gas, 8,661 Sm3/d condensate	Julimar-Brunello: Yes Wheatstone LNG: No
Australia Oil	Offshore Western Australia	Ngujima-Yin FPSO: 60% Okha FPSO: 33.33%	Ngujima-Yin FPSO: 120 kbbl/d oil Okha FPSO: 60 kbbl/d oil 82 MMscf/d gas	Yes

6 Recent Performance

Woodside benefited from a strong rebound in market conditions in 2021 following the challenges and uncertainty brought on by COVID-19 in 2020. Operating revenue rose 93% year-on-year to US$6,962 million primarily due to higher realised oil and spot LNG prices. A summary of key changes from the previous reporting periods are described in Part 17 (*Operating and Financial Review of Woodside*).

Financial Summary and Key Ratios				
US$ million		**2021**	**2020**	**2019**
Operating revenue		6,962	3,600	4,873
Underlying EBITDA[13]		4,135	1,922	3,531
EBIT[14]		3,493	(5,171)	1,091
Net profit after tax		1,983	(4,028)	343
Underlying net profit after tax[15]		1,620	447	1,063
Net cash from operating activities		3,792	1,849	3,305
Dividends distributed		404	766	1,189
Key ratios				
Return on equity	%	14.8	(33.4)	2.1
ROACE	%	15.6	(21.0)	4.1
Effective income tax rate[16]	%	32.0	20.5	57.2
Earnings	US cps	206.0	(423.5)	36.7
Gearing	%	21.9	24.4	14.4
Sales volumes				
Gas	MMboe	93.7	86.5	81.5
Liquids	MMboe	17.9	20.3	15.9
Total	MMboe	111.6	106.8	97.4

7 Projects and Growth Options

7.1 Scarborough and Pluto Train 2 development

Scarborough and Pluto Train 2 development overview and history

On 22 November 2021 Woodside announced that final investment decisions had been made to approve the Scarborough and Pluto Train 2 developments, including new domestic gas facilities and modifications to Pluto Train 1. On 18 January 2022 Woodside announced the completion of the sale of a 49% non-operating participating interest in the Pluto Train 2 Joint Venture to GIP. Woodside has retained a 51% participating interest in Pluto Train 2 Joint Venture. Woodside remains the operator of Pluto LNG and the Pluto Train 2 Joint Venture.

The Scarborough field is located approximately 375 km west-northwest offshore the Burrup Peninsula. Scarborough is part of the Greater Scarborough resource, including the Jupiter and Thebe fields.

[13] These are non-IFRS measures that are unaudited but derived from audited Financial Statements. These measures are presented to provide further insight into Woodside's performance. Refer to paragraph 6 of Part 17 *(Operating and Financial Review of Woodside)* for calculation methodologies.

[14] These are non-IFRS measures that are unaudited but derived from audited Financial Statements. These measures are presented to provide further insight into Woodside's performance. Refer to paragraph 6 of Part 17 *(Operating and Financial Review of Woodside)* for calculation methodologies.

[15] These are non-IFRS measures that are unaudited but derived from audited Financial Statements. These measures are presented to provide further insight into Woodside's performance. Refer to paragraph 6 of Part 17 *(Operating and Financial Review of Woodside)* for calculation methodologies.

[16] The global operations effective income tax rate is calculated as the Group's income tax expense/(benefit) dividend by profit/(loss) before income tax. The 2019 effective income tax rate was impacted by non-deductible foreign expenditure of US$242 million.

The Scarborough Joint Venture, through Woodside as operator, is developing the Scarborough gas resource through new offshore facilities connected by an approximately 430km pipeline to the second LNG train (Pluto Train 2) at the existing Pluto LNG onshore facility.

The Scarborough reservoir contains only around 0.1% CO_2. Scarborough gas processed through Pluto Train 2 will be one of the lowest carbon intensity sources of LNG delivered to customers in north Asia, with first LNG cargo targeted for 2026.

In the second quarter 2020, the Scarborough Offshore Project Proposal was accepted by the National Offshore Petroleum Safety and Environmental Management Authority ("NOPSEMA") and in the fourth quarter 2020, Production Licences were granted for the WA-61-L (Scarborough) and WA-62-L (North Scarborough) titles. Following approval by the Western Australia Minister for Environment of the Scarborough Nearshore Ministerial Statement 1172 in the third quarter 2021, all key primary environmental approvals were in place to support the final investment decisions.

In April 2022, further key primary approvals were received from the Commonwealth-Western Australian Joint Authority to support execution of the Scarborough Project. The Scarborough Joint Venture has received an offer for the pipeline licence to construct and operate the Scarborough pipeline in Commonwealth waters. Approval has also been granted for the Scarborough Field Development Plan (FDP), enabling Woodside to commence petroleum recovery operations from Petroleum Production Licences WA-61-L and WA-62-L. Following approval of the FDP, the Scarborough and Pluto Train 2 processing and services agreement executed in November 2021 is now unconditional.

Woodside notes that proceedings have been commenced seeking judicial review of certain approvals as further set out in paragraph 24 of Part 21 (*Additional Information*).

The cost estimate for the entire development is US$12.0 billion, (100% project, nominal), comprising US$5.7 billion for the offshore component and US$6.3 billion for the onshore component, which includes capital expenditure for the development of Pluto Train 2, modifications to Pluto Train 1 and a domestic gas processing facility.

Processing and services agreement

The Scarborough and Pluto Train 2 joint ventures have executed a binding processing and services agreement ("**PSA**") for the processing of Scarborough gas through the Pluto LNG Facilities. The PSA provides for the Scarborough Joint Venture to access LNG and domestic gas processing services at a rate of up to 8 million tonnes per annum of LNG and up to 225 terajoules per day of domestic gas for an initial period of 20 years, with options to extend.

The PSA is supported by associated processing and services agreements executed with the Pluto Joint Venture in respect of access to the existing Pluto LNG facilities.

About Scarborough

Scarborough lies within permits WA-61-L and WA-62-L. It is owned by Woodside (73.5%, operator) and BHP (26.5%). Woodside acquired its 73.5% participating interest in Scarborough through two acquisitions. Initially, in September 2016, Woodside acquired 25% of Scarborough from BHP. This was followed by an acquisition of 50% of Scarborough from ExxonMobil in March 2018 after which Woodside assumed operatorship. Following these transactions, in February 2020 Woodside and BHP agreed to unitise participating interests across the Scarborough (WA-1-R) and North Scarborough (WA-62-R) titles, resulting in Woodside's current interest of 73.5% interest in each title.

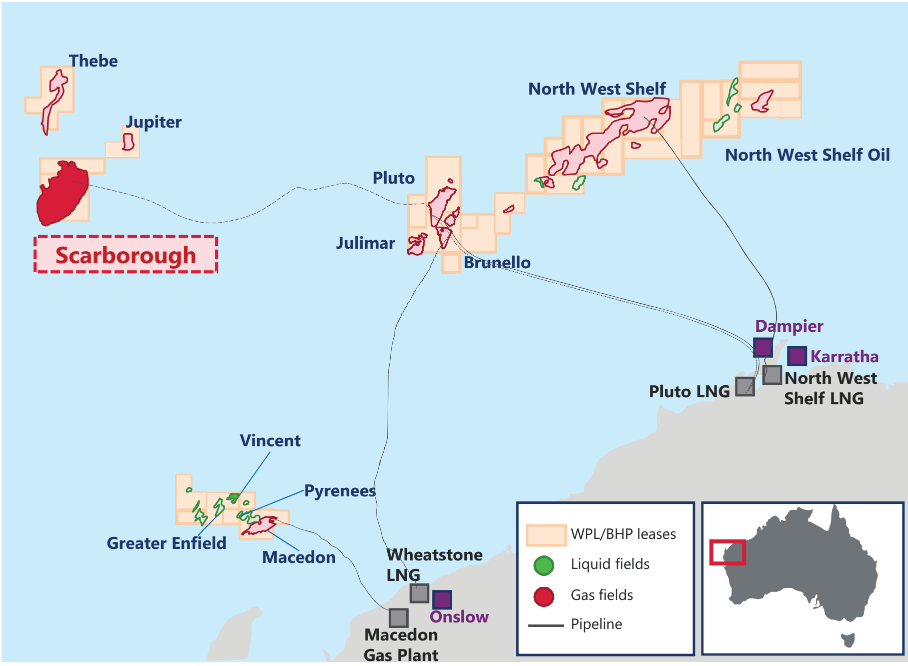
Woodside also owns an equal 50% participating interest with BHP Petroleum in the Thebe (WA-63-R) and Jupiter (WA-61-R) fields, which are part of the Greater Scarborough fields and options for potential future subsea tie-backs to the Scarborough Floating Production Unit ("**FPU**").

About Pluto LNG and Pluto Train 2

On 15 November 2021, Woodside entered into a sale and purchase agreement with GIP for the sale of a 49% non-operating participating interest in the Pluto Train 2 Joint Venture. The effective date of the transaction is

1 October 2021 and completion occurred on 18 January 2022. Pluto Train 2 is a key component of the Scarborough development and includes a new LNG train and domestic gas facilities to be constructed at the existing Pluto LNG onshore facility. The development of Pluto Train 2 is supported by the PSA entered into between the Pluto Train 2 and Scarborough joint ventures. In addition to its 49% share of capital expenditure, the agreement requires GIP to fund an additional amount of construction capital expenditure of US$822 million. Woodside's joint venture capital contributions will be reduced accordingly. The estimated capital expenditure for the development of Pluto Train 2 from 1 October 2021 is US$5.6 billion (100% project). If the total capital expenditure incurred is less than US$5.6 billion, GIP will pay Woodside an additional amount equal to 49% of the under-spend. In the event of a cost overrun, Woodside will fund its 51% share plus up to US$822 million in respect of GIP's 49% share of any overrun (after which the cost overruns are borne in accordance with their respective equity share). Delays to the expected start-up of production will result in payments by Woodside to GIP in certain circumstances.

Figure 5 – Scarborough project map[17]



Onshore infrastructure

Pluto Train 2	
Location	1,260km north of Perth, WA
Facility type	Onshore gas plant
Facility features	1 LNG processing train, 1 domestic gas facility
Product	LNG and domestic gas
FID	22 November 2021
Targeted first LNG cargo	2026
Capacity	LNG: 5.0 Mtpa Domestic Gas: 225 TJ/d

[17] Fields, blocks and pipelines shown in maps are stylised and not to scale. These maps are intended to show the general location and proximity of Woodside and BHP Petroleum's Carnarvon Basin assets. Map only shows the key Woodside and BHP Petroleum fields, leases and pipelines which are referenced in the Woodside and BHP Petroleum overview sections of this Prospectus.

Offshore infrastructure

Scarborough	
Location	375km north-west off the Burrup Peninsula, Western Australia
Processing facility type	Semi-submersible FPU
Fields	Scarborough (WA-61-L and WA-62-L) Thebe (WA-63-R) and Jupiter (WA-61-R) combined with Scarborough to constitute Greater Scarborough
Product	Dry gas
Production Capacity	Dry gas: 33,582 tonnes/d
FID	22 November 2021
Targeted first LNG cargo	2026
Production wells	8 planned in Phase 1 with 13 across life of field
Subsea pipelines	430km trunkline to Pluto LNG

On 18 January 2022 Woodside announced the completion of the sale of a 49% non-operating participating interest in the Pluto Train 2 Joint Venture to GIP. Woodside has retained a 51% participating interest in Pluto Train 2 Joint Venture. Woodside remains the operator of Pluto LNG and the Pluto Train 2 Joint Venture.

7.2 Pluto-KGP Interconnector

Pluto-KGP Interconnector overview

The Pluto-KGP Interconnector is a 3.2 kilometre pipeline which connects Pluto with KGP, providing access for other resource owners' gas to be processed at KGP. The Pluto-KGP Interconnector supports the accelerated production of gas from the first phase of Pluto's Pyxis Hub by enabling it to be processed at KGP. Processing of Pluto gas at KGP commenced in March 2022. The design capacity of the pipeline is more than 5 Mtpa.

7.3 Sangomar

Sangomar Field Development Phase 1 overview and history

The Sangomar Oil Field Development, containing both oil and gas, is located 100km south of Dakar and will be Senegal's first offshore oil development. The project is designed to allow subsequent development phases, including options for potential gas export to shore and future subsea tiebacks from other reservoirs and fields. Phase 1 total cost is estimated to be US$4.6 billion (100% project).

On 9 January 2020, Woodside Energy Finance (UK) Ltd entered into a secured loan agreement with Société Des Petroles Du Senegal ("**Petrosen**") (the Senegal NOC), to provide up to US$450 million for the purpose of funding capital construction costs associated with the Sangomar Oil Field Development. The facility has a maximum term of 12 years and semi-annual repayments of the loan are due to commence at the earlier of 12 months after ready for start-up or 30 June 2025. The carrying amount of the loan receivable is US$335 million as at 31 December 2021 which approximates its fair value.

Woodside made a final investment decision in relation to the Sangomar Field Development Phase 1 in January 2020, and the development drilling programme commenced in July 2021. First oil production is currently targeted for 2023.

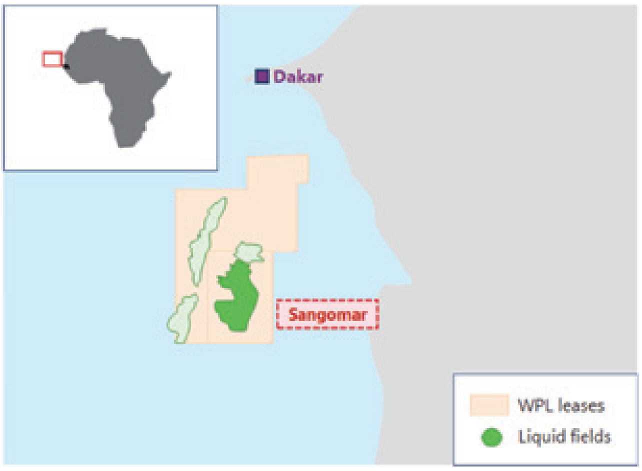
Ownership structure and joint venture

On 4 September 2020 Woodside Energy (Senegal) B.V. executed a sale and purchase agreement to acquire Capricorn Senegal Limited's entire participating interest in the Rufisque, Sangomar and Sangomar Deep ("**RSSD**") joint venture. The transaction completed on 22 December 2020.

On 19 January 2021 Woodside Energy (Senegal) B.V. executed a sale and purchase agreement with FAR Limited and FAR Senegal RSSD SA to acquire FAR Senegal RSSD SA's entire participating interest in the RSSD joint venture. The transaction completed on 7 July 2021.

Woodside currently owns an 82% participating interest in the Sangomar Field Development Phase 1 and a 90% participating interest in the remaining RSSD evaluation area. Woodside's joint-venture partner is Petrosen. The project is operated under Senegal's Production Sharing Contract regime.

Figure 6 – Sangomar Project map[18]



Offshore infrastructure

Sangomar	
Location	100km south of Dakar in Senegal
Processing facility type	Stand-alone FPSO facility
Fields	Senegal Sangomar, contained within the Sangomar Deep block covered by the RSSD PSC
Product	Oil and gas
Production capacity	Oil: 100 kbbl/d
FID	January 2020
Targeted first oil	2023
Production wells	23 planned for Phase 1

A sell-down process has been launched with the objective of reducing Woodside's equity interest in the RSSD joint venture to a targeted 40-50%, subject to receiving competitive proposals from high-quality counterparties.

8 Other Development Options

8.1 Browse

Browse Project overview and history

The Browse resource is located in the offshore Browse Basin, approximately 425km north of Broome in Western Australia, comprising of the Brecknock, Calliance and Torosa fields.

Woodside is investigating opportunities to support commercialisation of the Browse resource, including the assessment of the technical, commercial and regulatory feasibility of carbon capture and storage.

Woodside is targeting front-end engineering design entry in 2023.

[18] Fields and blocks and pipelines are stylised and not to scale. Map only shows Woodside fields and leases and pipelines which are referenced in the Woodside Overview section of this Prospectus.

Ownership structure and joint venture

Browse lies within permits WA-28-R, WA-29-R, WA-30-R, WA-31-R and WA-32-R. It is owned by Woodside (30.60%, Operator), Shell (27.00%), BP (17.33%), MIMI (14.40%) and China National Petroleum Company (10.67%).

8.2 Myanmar

Block A-6 is in the Rakhine Basin, offshore Myanmar. Woodside condemns human rights violations and has watched with growing concern developments in Myanmar since the events of 1 February 2021. Woodside supports the people of Myanmar and hopes for a peaceful journey to democracy. Woodside has commenced arrangements to formally exit all Blocks in which it participates in Myanmar including AD-7, A-7, AD-1, AD-8 and A-6.

8.3 Sunrise

Overview

The Sunrise development comprises the Sunrise and Troubadour gas and condensate fields, collectively known as Greater Sunrise. The fields are located approximately 150km south-east of Timor-Leste and 450km north-west of Darwin, Australia.

The Sunrise Joint Venture remains committed to the development of Greater Sunrise provided there is fiscal and regulatory certainty necessary for commercial development to proceed.

Ownership structure and joint venture

Sunrise holds 78.9% in NT/RL2, 1% in NT/RL4, 20% in PSC 03-19 and 0.1% in PSC 03-20. It is owned by Woodside (33.44%, Operator), Timor GAP, E.P. (56.56%) and Osaka Gas Co. Ltd. (10%).

8.4 Kitimat

Overview

Woodside announced in May 2021 its intention to exit its 50% non-operated participating interest in the proposed Kitimat LNG development, located in British Columbia, Canada. Exit activities progressed as planned with commercial agreement terminations, lease relinquishment and remediation planning well underway. The sale of the Pacific Trail Pipeline route to Enbridge Inc. was completed in December 2021.

The exit will include the divestment or wind-up and restoration of assets, leases and agreements covering the 480 km Pacific Trail Pipeline route and the site for the proposed LNG facility at Bish Cove. Exit activities are progressing as planned with commercial agreement terminations, lease relinquishment and remediation planning well underway.

Woodside is investigating potential future natural gas, ammonia and hydrogen opportunities that could utilise the Liard Basin upstream gas assets.

8.5 Exploration

Woodside maintains a global exploration and appraisal programme designed to enhance future growth. Woodside looks for material positions in world-class assets that are aligned with its capabilities and current portfolio, targeting exploration opportunities close to existing infrastructure and low-cost commercialisation. Woodside's active exploration regions are in Australia, Senegal, South Korea and Congo. Woodside's exploration activities in Australia are focused primarily on low cost near field and infill opportunities. Outside Australia, Woodside's exploration efforts are focused around existing hubs in proven or emerging basins.

Woodside has been consolidating global exploration activities as macroeconomic factors evolve, maintaining a strategy of divesting low-value licences while continuing to assess sustainable growth opportunities.

9 Summary of reserves and resources determined by the Competent Person

Woodside's Net Reserves as at 31 December 2021

Country	Asset	Oil and Condensate Reserves (MMbbl)		Gas Reserves (Bcf)	
		1P	2P	1P	2P
Australia	Greater Pluto	19.5	24.3	1575.3	1951.2
	NWS	24.0	30.7	715.2	943.3
	Greater Enfield	16.0	24.1	0.0	0.0
	Wheatstone	8.8	16.5	608.9	947.4
	Scarborough	0.0	0.0	5,267.9	8,210.6
Senegal	Sangomar	100.6	148.10	0.0	0.0
	Total	**168.9**	**243.7**	**8,167.4**	**12,052.5**

Notes:
1. Net Reserves are Woodside's net economic entitlement volume after deduction of royalties or, according to the terms of the PSC governing the assets.
2. Net gas reserves include NGL volumes and 806 Bcf (1P)/1,181 Bcf (2P) consumed in downstream operations (CiO or fuel); the Competent Person's Report presents CiO volumes, company net NGL reserves and company net gas reserves excluding fuel in separate tables.
3. Sangomar Reserves include production through to the end of the relevant concessions only.
4. Totals may not exactly equal the sum of the individual entries because of rounding.

Woodside's Net Contingent Resources as at 31 December 2021

Country	Asset	Net 2C Contingent Resources	
		Oil and Condensate (MMbbl)	Gas (Bcf)
Australia	Greater Pluto	22.8	1,290
	NWS	20.6	293
	Greater Enfield	34.4	313
	Wheatstone	0.2	15
	Greater Scarborough	0.0	659
	Greater Browse	119.3	4,469
	Greater Sunrise	75.6	1,717
Myanmar	Myanmar A6	0.0	567
Senegal	Sangomar Phase 2	317.1	301
Canada	Liard	0.0	13,350
	Total	**590.0**	**22,974**

Notes:

1. Net Contingent Resources in this table are Woodside's working interest fraction of the field's Contingent Resources; they do not represent Woodside's actual net entitlement under the terms of the contracts that govern the assets, which would be lower for PSCs or where royalty is deductible.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the asset may not be developed in the form envisaged or may not be developed at all (i.e. no "Chance of Development" (Pd) factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Gas contingent resources include NGL volumes
5. Totals may not exactly equal the sum of the individual entries because of rounding.
6. No deduction has been made for fuel, flare and shrinkage.
7. The Competent Person's Contingent Resource volume for Liard (Canada) shown is based on a working interest of 50.0% on the basis that not all the infrastructure-free leases have been transferred. Woodside applies a working interest of 94.9% based on full equity in 28 non infrastructure related Liard Basin leases from Chevron Canada

10 Competition

Woodside's major immediate competitors are other companies engaged in the acquisition, exploration, appraisal and production of oil, condensate, LPGs, natural gas and LNG, which may be state owned, independently owned, or publicly listed entities. Other energy companies may have greater assets, employees, intellectual property and access to finance than those available to Woodside. Other competitors could also include those companies engaged in production or provision of alternative or renewable energies, such as wind, solar, hydropower, hydrogen or ammonia. Woodside's ability to monetise its reserves and increase production is contingent on Woodside's ability to progress development of the projects in its portfolio, plus the potential acquisition and development of new exploration acreage or other energy assets. In addition, competition exists in the pricing of energy and energy products, as well as the supply, distribution, and marketing of such products in a reliable manner.

11 Key Strengths

1. Oil and FPSOs

   Woodside made the first oil discovery offshore Western Australia – the Legendre field in 1968. Since 1995, Woodside has produced oil via floating production storage and offloading (FPSO) vessels, and currently it operates facilities, and offloading FPSO facilities, the Okha FPSO and Ngujima-Yin FPSO. Woodside's operated assets are renowned for their safety, reliability, efficiency and environmental performance history and have a strong track record in project development.

2. Subsea and pipelines

   With a track record of oil and gas developments spanning a variety of conditions in Australia and internationally, Woodside is experienced in designing, constructing and operating a large portfolio of subsea equipment and oil and gas transmission pipelines. With extensive infrastructure in place and a significant portfolio of proposed developments, Woodside offers unique subsea and pipelines growth opportunities in its areas of operation.

3. LNG

   Since 1984, Woodside has been operating the Australian project, the North West Shelf, and it remains one of the world's premier LNG facilities. In 2012, Woodside added the Pluto LNG Plant to its onshore operating facilities. As an Australian leading LNG operator, Woodside operated 5% of global LNG supply in 2021. Woodside is known as a reliable and safe LNG supplier and has enduring relationships with foundation customers throughout the Asia-Pacific region that span more than 30 years. Woodside is transforming to become a global business and are pursuing new development concepts, technology and contracting strategies for earliest commercialisation of its significant global LNG interests. Woodside is also connecting Pluto LNG with the North West Shelf Project to create an integrated LNG production hub on the Burrup Peninsula.

4. Environment

   Strong partnerships, sound research and transparency are the key elements of Woodside's approach to the environment. Woodside operates in a range of marine and terrestrial environments. Woodside's long-term business success depends on its ability to understand current and future operating environments, the potential impact of Woodside's activities and success in managing and mitigating the impact of these activities. Throughout Woodside's greater than 60 year history, the company has not experienced any uncontrolled release of hydrocarbons as a result of loss of well control. This is a testament to Woodside's systematic approach to managing the safety and integrity of its drilling and completions activities.

5. Community

   Woodside recognises that long-term meaningful relationships with communities are fundamental to maintaining Woodside's licence to operate, and works to build mutually beneficial relationships in all locations where Woodside is active. Woodside understands that each community is unique, and Woodside's goal is to have local representation and processes in place to ensure Woodside understands and responds to local community issues, aspirations and expectations. Through social contribution Woodside is creating long-term capacity and capability to ensure that host communities benefit from Woodside's presence. Each year Woodside provides financial and in-kind support to a wide range of community groups. Woodside's social contribution priority areas align with the United Nations Sustainable Development Goals and are applied globally. Internationally, Woodside is progressing a combined approach to environmental and social performance to support early activities such as exploration, seismic acquisition and drilling.

6. Technology

   Technology and innovation are essential to Woodside's long-term sustainability. Woodside is growing carbon and new energy businesses, using technology to reduce emissions and the carbon footprint of Woodside's products. Woodside is pioneering remote support and the application of artificial intelligence, embedding advanced analytics across operations.

7. Capital management

   Woodside takes a disciplined and prudent approach to capital management, ensuring management of financial risks and maintenance of a resilient financial position. This allows Woodside to maximise the value delivered from its portfolio of opportunities. Woodside responded to the uncertain global investment environment arising from the spread of COVID-19, combined with lower oil and gas prices, by taking a prudent approach to cashflow management and implementing a number of cash preservation measures. Woodside's balance sheet strength and disciplined approach to capital management provide optionality to pursue inorganic growth opportunities should they emerge.

12 Woodside Directors and Executive Committee

1. Woodside Board of Directors

As at the date of this Prospectus, the directors of Woodside are:

i. Richard Goyder AO: Chair;

ii. Meg O'Neill: Chief Executive Officer and Managing Director;

iii. Larry Archibald: Independent Non-Executive Director;

iv. Frank Cooper AO: Independent Non-Executive Director;

v. Swee Chen Goh: Independent Non-Executive Director;

vi. Ian Macfarlane: Independent Non-Executive Director;

vii. Christopher Haynes OBE: Independent Non-Executive Director;

viii. Ann Pickard: Independent Non-Executive Director;

ix. Gene Tilbrook: Independent Non-Executive Director;

x. Sarah Ryan: Independent Non-Executive Director; and

xi. Ben Wyatt: Independent Non-Executive Director.

If the Merger is implemented, the Woodside Board is expected to be reconstituted as described in Part 12 *(Directors, Senior Executives and Corporate Governance)* of this Prospectus.

2. Executive Committee

As at the date of this Prospectus, Woodside's executive committee is as follows:

i. Meg O'Neill: Chief Executive Officer and Managing Director;

ii. Graham Tiver: Executive Vice President and Chief Financial Officer;

iii. Shaun Gregory: Executive Vice President Sustainability and Chief Technology Officer;

iv. Fiona Hick: Executive Vice President Operations;

v. Daniel Kalms: Senior Vice President Merger Integration;

vi. Tom Ridsdill-Smith: Senior Vice President Climate;

vii. Julie Fallon: Acting Senior Vice President Corporate and Legal;

viii. Jacky Connolly: Vice President People and Global Capability;

ix. Mark Abbotsford: Vice President Marketing, Trading and Shipping; and

x. Menno Weustink: Acting Vice President Development.

13 Group structure

Set out below is Woodside's list of subsidiaries. The list of subsidiaries contains all group members with the exception of certain entities in which Woodside holds an insignificant minority shareholding.

	Entity	Location	Ownership
	Woodside Petroleum Ltd[5]	Australia	100.00%
	Woodside Petroleum Holdings Pty Ltd	Australia	100.00%
	North West Shelf Liaison Company Pty Ltd	Australia	33.34%^[6]
	North West Shelf Shipping Service Company Pty Ltd	Australia	33.34%^[6]
	North West Shelf Lifting Coordination Pty Ltd	Australia	33.34%^[7]
	North West Shelf Gas Pty Limited	Australia	33.34%^[7]
	International Gas Transportation Company Limited	Bermuda	33.34%^[7]
	China Administration Company Pty Ltd	Australia	33.34%^[8]
	Woodside Finance Limited	Australia	100.00%
	Woodside Petroleum (Timor Sea 19) Pty Ltd	Australia	100.00%
	Woodside Petroleum (Timor Sea 20) Pty Ltd	Australia	100.00%
	Mermaid Sound Port and Marine Services Pty Ltd	Australia	100.00%
	Woodside Energy Ltd	Australia	100.00%
	Woodside Energy Holdings (UK) Pty Ltd	Australia	100.00%
	Woodside Energy Services (Qingdao) Co., Ltd	China	100.00%
	Woodside Energy (UK) Limited	UK	100.00%
	Woodside Energy Finance (UK) Limited	UK	100.00%
	Woodside Energy (Bulgaria) Limited	UK	100.00%
	Woodside Energy (Congo) Limited	UK	100.00%
	Woodside Energy (France) SAS	France	100.00%
	Woodside Energy Iberia S.A.	Spain	100.00%
	Woodside Energy (N.A.) Ltd	England and Wales	100.00%
	Woodside Energy Holdings (Senegal) Limited	UK	100.00%
	Woodside Energy (Senegal) B.V.	Netherlands	100.00%
	Woodside Energy Holdings Pty Ltd	Australia	100.00%
	Woodside Energy (Myanmar) Pte Ltd	Singapore	100.00%
	Woodside Energy (Cameroon) SARL	Cameroon	100.00%
	Woodside Energy (New Zealand) Limited	New Zealand	100.00%
	Woodside Energy (New Zealand 55794) Limited	New Zealand	100.00%
	Woodside Energy (Senegal) Pty Ltd	Australia	100.00%
	Woodside Energy (Tanzania) Limited	Tanzania	100.00%[2]
	Woodside Energy (Korea) Pte Ltd	Singapore	100.00%
	Woodside Energy (Korea II) Pte Ltd	Singapore	100.00%
	Woodside Energy (Peru) Pty Ltd	Australia	100.00%
	Woodside Energy (Indonesia) Pty Ltd	Australia	100.00%
	Woodside Energy (Indonesia II) Pty Ltd	Australia	100.00%
	Woodside Energy (Malaysia) Pty Ltd	Australia	100.00%
	Woodside Energy (Ireland) Pty Ltd	Australia	100.00%
	Woodside Energy (Morocco) Pty Ltd	Australia	100.00%
	Woodside Energy (Gabon) Pty Ltd	Australia	100.00%
	Woodside Energy Holdings (USA) Inc	USA	100.00%
	Woodside Energy (USA) Inc	USA	100.00%

	Gryphon Exploration Company	USA	100.00%
	Woodside Energy Holdings II Pty Ltd	Australia	100.00%
	Woodside Power Pty Ltd	Australia	100.00%
	Woodside Power (Generation) Pty Ltd	Australia	100.00%
	Woodside Energy Holdings (South America) Pty Ltd	Australia	100.00%
	Woodside Energia (Brasil) Apoio Administrativo Ltda	Brazil	100.00%[3]
	Woodside Energy Holdings International Pty Ltd	Australia	100.00%
	Woodside Energy Mediterranean Pty Ltd	Australia	100.00%
	Woodside Energy International (Canada) Limited	Canada	100.00%
	Woodside Energy (Canada PTP) Limited	Canada	100.00%
	Woodside Energy (Canada LNG) Limited	Canada	100.00%
	KM LNG Operating General Partnership	Canada	100.00%[1]
	KM LNG Operating Ltd	Canada	100.00%
	Woodside Energy Trading Singapore Pte Ltd	Singapore	100.00%
	Woodside Energy Shipping Singapore Pte Ltd	Singapore	100.00%
	WelCap Insurance Pte Ltd	Singapore	100.00%
	Woodside Energy Carbon Holdings Pty Ltd	Australia	100.00%
	Woodside Energy Carbon (Assets) Pty Ltd	Australia	100.00%
	Woodside Energy Carbon (Services) Pty Ltd	Australia	100.00%
	Woodside Energy (Financial Advisory Services) Pty Ltd	Australia	100.00%
	Woodside Burrup Pty Ltd	Australia	100.00%
	Woodside Burrup Train 2 A Pty Ltd	Australia	100.00%
	Woodside Burrup Train 2 B Pty Ltd	Australia	100.00%
	Woodside Energy (LNG Fuels and Power) Pty Ltd	Australia	100.00%
	Woodside Energy (Domestic Gas) Pty Ltd	Australia	100.00%
	Burrup Facilities Company Pty Ltd	Australia	90.00%^[4]
	Burrup Train 1 Pty Ltd	Australia	90.00%^[4]
	Pluto LNG Pty Ltd	Australia	90.00%^[4]
	Woodside Energy Technologies Pty Ltd	Australia	100.00%
	Woodside Technology Solutions Pty Ltd	Australia	100.00%
	Woodside Energy Scarborough Pty Ltd	Australia	100.00%
	Woodside Browse Pty Ltd	Australia	100.00%
	Woodside Energy Julimar Pty Ltd	Australia	100.00%
	Woodside Energy Australia Asia Holdings Pte Ltd	Singapore	100.00%
	Woodside Energy (Algeria) Pty Ltd	Australia	100.00%
	Woodside Energy (Norway) Pty Ltd	Australia	100.00%
	Metasource Pty Ltd	Australia	100.00%

Notes: (^) Remainder of shares externally owned.

(1) As at 31 December 2020, Woodside Energy International (Canada) Limited and Woodside Energy (Canada LNG) Limited were the general partners of the KM LNG Operating General Partnership holding a 99.99% and 0.01% partnership interest, respectively.

(2) As at 31 December 2020, Woodside Energy Holdings Pty Ltd held a 99.99% interest in the shares of Woodside Energy (Tanzania) Limited and Woodside Energy Ltd held the remaining 0.01% interest.

(3) As at 31 December 2020, Woodside Energy Holdings (South America) Pty Ltd held a 99.99% interest in the shares of Woodside Energia (Brasil) Apoio Adminstrativo Ltda and Woodside Energy Ltd held the remaining 0.01% interest.

(4) Kansai Electric Power Australia Pty Ltd and Tokyo Gas Pluto Pty Ltd each hold a 5% interest in the shares of these subsidiaries. These subsidiaries are controlled.

(5) To be renamed Woodside Energy Group Ltd prior to Admission, subject to approval by the Woodside Shareholders at the Woodside Shareholders' Meeting.

(6) The Merged Group will own 33.34% of NWS joint ventures with 16.67% held by Woodside Petroleum Holdings Pty Ltd and 16.67% held by BHP Petroleum Pty Ltd.

(7) The Merged Group will own 33.34% of NWS joint ventures with 16.67% held by Woodside Petroleum Holdings Pty Ltd and 16.67% held by BHP Petroleum (North West Shelf) Pty Ltd.

(8) The Merged Group will own 33.34% of NWS joint ventures with 16.67% held by Woodside Petroleum Ltd and 16.67% held by BHP Petroleum (North West Shelf) Pty Ltd.

Note: where the shade of colour changes, the entity listed directly above the subsidiary is the parent.

Subsidiary Level I

Subsidiary Level II

Subsidiary Level III

Subsidiary Level IV

Subsidiary Level V

14 Values and Strategy

Values

The Woodside Compass defines Woodside's fundamental values. The Woodside Compass also provides clear direction on where Woodside is going, and how it will get there. The values of the Woodside Compass are as follows:

Respect – we give everyone a fair go, give and receive feedback and listen with empathy

Ownership – we set goals, hold ourselves accountable and learn, including from mistakes

Sustainability – we keep each other safe, look after the environment and support our community

Working Together – we embrace inclusion, value diversity and build long-term relationships

Integrity – we are transparent, honest and fair and build trust by doing the right thing

Courage – we speak up, act decisively and embrace change

Woodside's Foundation	• Operations are characterised by strong LNG reliability, cost discipline and strong safety and environmental performance • Continue to maintain competitive advantage through sustained operational excellence, resources in close proximity to growth markets, acute cost focus and continued innovation in technology
Pursuing Energy Growth	• Progressing an attractive portfolio of development projects to unlock value for shareholders and other stakeholders • Final investment decisions have been made in relation to the Scarborough and Pluto Train 2 developments with first LNG cargo targeted for 2026. • Project execution for Sangomar Oil Field Development well-advanced and first oil targeted for 2023 • Capital allocation will be disciplined to build a low cost, lower carbon portfolio that is profitable, resilient and diversified
Energy Transition Goals	• Managing energy transition through the development of diversified and resilient portfolio, broader decarbonisation of the business and incremental investment in new energy products and lower-carbon services • Setting near and mid-term net emissions reduction targets intended to put Woodside on a pathway to net zero equity Scope 1 and Scope 2 emissions by 2050 • Developing Woodside's lower-carbon business, and actively generating sources for carbon offsets of Scope 1 and Scope 2 emissions • Pursuing complementary opportunities that offer optionality around traditional assets that may diversify revenue streams • Sharing knowledge and building capabilities through partnerships

15 Strategy

Woodside has developed a strategy to deliver positive stakeholder outcomes by pursuing a portfolio of low-cost and lower-carbon growth opportunities. As outlined below, Woodside's strategy is underpinned by a robust base business, innovative technology and a prudent approach to capital allocation which provides the foundation to progress key development projects and to navigate the energy transition.

16 ESG

In 2021, Woodside maintained its 'AAA' leader rating in the Morgan Stanley Capital International ESG ratings for the eighth consecutive year.

17 Environmental

Strong environmental performance is essential to Woodside's success and continued growth, Woodside strives to reduce its environmental footprint across all phases of the operating life cycle with a key emphasis on learning and continuous improvement.

Woodside's approach to environmental management is governed by its Health, Safety and Environment (HSE) Policy and Environmental Management Approach that apply to all activities under Woodside operational control. Woodside's environmental risk management process allows it to consistently address the environmental impacts and risks associated with Woodside's activities across all operating locations and regulatory regimes.

Woodside relies on evidence-based scientific knowledge to support its understanding of the environments where it operates. This informs Woodside's risk evaluations of its potential impacts on biodiversity and the local environment and is critical to making the right environmental decisions.

Woodside regularly reassess environmental impacts and risks of operations across its portfolio at the activity level. This is to ensure emerging scientific understanding and best practices are captured in these assessments, ultimately resulting in more robust environmental outcomes. This is aligned with the intent of the International Standard ISO31000 2018 Risk Management Guideline.

18 Climate Change

Woodside's climate strategy comprises of reducing its net equity Scope 1 and 2 greenhouse gas emissions, and investing in the products and services to help customers reduce their emissions.

Emissions Reductions

Woodside sets its Scope 1 and 2 greenhouse gas emissions targets on an equity basis. This ensures that the scope of emissions reduction targets is aligned with its economic interest in its investments. Equity emissions reflect the greenhouse gas emissions from operations according to Woodside's share of equity in the operation. The equity share reflects economic interest, which is the extent of rights a company has to the risks and rewards flowing from an operation. Woodside also intends to set its emissions reduction targets on a net basis, allowing for both direct emissions reductions from its operations and emissions reductions from the use of offsets.

Woodside has established near and medium-term targets to reduce its net equity share Scope 1 and 2 greenhouse gas emissions by 15% by 2025 and 30% by 2030 relative to the gross annual average for the period 2016–2020[19]. Woodside plans to meet these targets by:

- Limiting emissions through the design of facilities;
- Reducing emissions through the operation of facilities; and
- Offsetting emissions, by both originating and acquiring quality offsets.

Woodside is the largest Australian LNG operator and in 2021 it operated 5% of global LNG supply. The International Energy Agency expects natural gas to remain an important part of electricity system flexibility and to continue to be used by customers to support decarbonisation. Emissions from using natural gas to generate electricity are significantly lower than when using coal to produce the same amount of electricity. Natural gas is also expected to continue to be used in high-temperature industrial processes and for non-energy purposes, such as a chemical feedstock, where substitution with alternatives may not currently be technically or economically viable.

Offsets

Woodside is building a portfolio of offsets and offset origination projects from which to meet a portion of the expected future regulatory requirements and corporate emissions reduction targets. This approach is intended to manage the risk that the costs, availability and regulatory framework for offsets changes in the future, by developing a diverse portfolio differentiated by vintage, methodology and geography.

Woodside recognises that there are important conditions on the use of offsets, including that the emissions reduction hierarchy should prioritise avoiding and reducing emissions before offsetting them, and that offsets must be verified as additional, scientifically valid and accurately accounted for using robust methodologies.

At present Woodside uses international offsets accredited by two independent non-government organisations: Verra and Gold Standard. These international programmes are chosen because they also deliver offset integrity, with similar standards to those required for Australian Carbon Credit Units ("ACCUs"). Verra and Gold Standard offsets are recognised under the Australian Government's Climate Active Carbon Neutral Standard as genuine carbon reduction that can be used for certification of net carbon neutrality.

Through developing its own projects, Woodside plans to generate its own offsets with a focus on co-benefits delivery such as biodiversity, regional economic development and indigenous participation.

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[19] Target is for net equity Scope 1 and 2 greenhouse gas emissions, relative to a starting base of the gross average equity Scope 1 and 2 emissions over 2016-2020 and may be adjusted (up or down) for potential equity changes in producing or sanctioned assets with an FID prior to 2021. After Implementation, the baseline will be adjusted for the Merged Group portfolio.

Woodside has a diverse portfolio of offsets which mitigates the risk of a single event materially impacting the overall portfolio and the ability to meet future obligations. Woodside actively manages the origination projects for which it is the project proponent. For offsets procured from third parties it relies on the governance processes of the certification organisation (Verra, and Gold Standard). Project performance is monitored across the offset portfolio, and where yields on origination projects are not sufficient to meet overall offset generation expectations portfolio-wide, additional sources of offsets are procured. For procured offsets, the targeted standards have rules and guidelines for the management of underperforming projects, with both Verra and Gold Standard requiring buffers from project proponents to mitigate loss of offsets due to underperformance of the project protecting the buyers of these offsets.

The use of international offsets accredited by independent non-governmental organisations or ACCUs regulated by the Australian Government allows for the validation of actual offset project outcomes against estimates, as offsets units that meet these integrity standards include third-party scientific verification and certification of offset generation.

Woodside estimates the quantity of offsets required to meet a portion of the expected future regulatory requirements and corporate emissions targets through integrated production and greenhouse gas emissions forecasting and considering risk factors associated with oil and gas businesses, including but not limited to: drilling and production results, reserves estimates, loss of market, physical risks and project delay or advancement, as well as assessment of current and possible future greenhouse gas regulatory requirements and abatement able to be delivered through engineering of operational changes. Estimates are compared to actual results at the asset and divisional level to provide insight on performance against emissions reduction targets as well as to improve the accuracy of future forecasts.

New Energy

Woodside is also focused on maturing its portfolio of new energy opportunities in Australia and internationally and over the course of 2021, progressed studies and commercial discussions with third parties to advance various hydrogen and ammonia opportunities. Woodside also continues to assess carbon capture and storage opportunities which includes screening for suitable reservoirs which if pursued, could reduce or offset Woodside's carbon emissions and those of other third-party emitters.

19 Social and community

Woodside recognises the importance of its role to manage the impacts of its activities on communities to deliver mutually beneficial and sustainable social outcomes in the areas where it operates. Woodside's interactions with local communities are guided by its Sustainable Communities Policy and the Indigenous Communities Policy.

Woodside regularly engages with key stakeholders and the broader communities where it operates to identify and understand expectations and manage potential impacts related to its activities. This includes Karratha, Roebourne and Exmouth in north-western Australia and Senegal.

Engagement with Traditional Owners and Custodians in Karratha and Roebourne is focused on cultural heritage management for Woodside's operations on the Burrup Peninsula, also known as Murujuga, and other matters including Indigenous contracting and employment, and social investment. Comprehensive cultural heritage management plans are in place to monitor and manage environmental impacts on cultural heritage, including rock art. The term "Traditional Owners and Custodians" refers to Aboriginal people who, in accordance with Aboriginal tradition, hold particular knowledge about and can speak for the cultural heritage value of a particular area and have traditional rights, interests and responsibilities in respect of Aboriginal places, objects or ancestral remains located in or reasonably expected to have originated from a particular area. Traditional Owners and Custodians have a social, economic or spiritual affiliation with, and responsibilities for, an Aboriginal site or object.

Woodside maintains active social investment programmes where it operates. Partnerships are based on established relationships with stakeholders and host communities, with the aim of increasing long-term community capability. A new five-year approach from 2021 identifies three social outcome focus areas to support community development and long-term outcomes. Woodside engages actively with local businesses and services in Australia and Senegal to support initiatives to help small businesses to effectively engage in the supply chain and build capability.

20 Governance

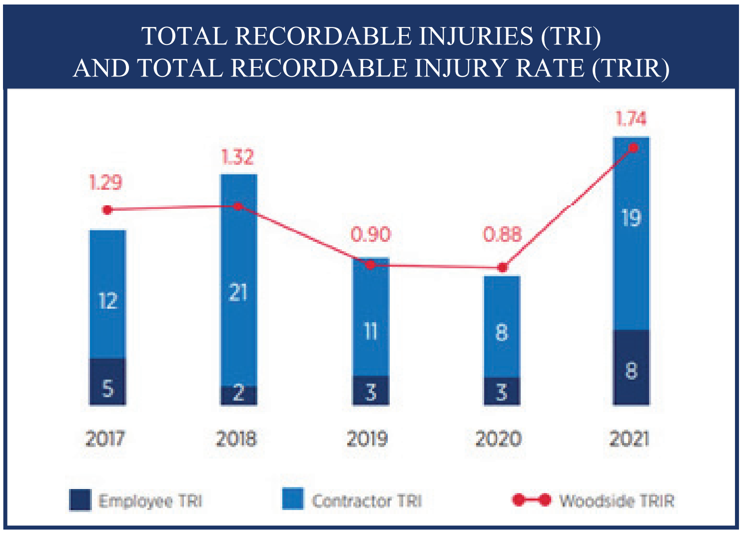
See paragraph 2 of Part 12 *(Directors, Senior Executives and Corporate Governance)* of this Prospectus for more information on Woodside's Sustainability Committee and corporate governance initiatives around ESG.

21 Health and Safety

Woodside is committed to providing workplaces where its people and contractors are physically and psychologically safe, healthy and well. Woodside's Safety Culture framework governs behavioural expectations required at all levels of the organisation to build and sustain an effective safety culture. Woodside continually seeks to learn and to improve with an emerging focus on leveraging technology to reduce risk. Further, there is a focus on promotion of positive practices and providing support services to enhance employee wellbeing and to effectively manage workplace risks to mental health.

Woodside had an increase in personal injury rates in 2021, in contrast with a downward trend in previous years. Improving safety performance is a priority for Woodside in the year ahead and it will achieve this by addressing common root causes for the 2021 incidents.

Figure 7: Total recordable injury rate



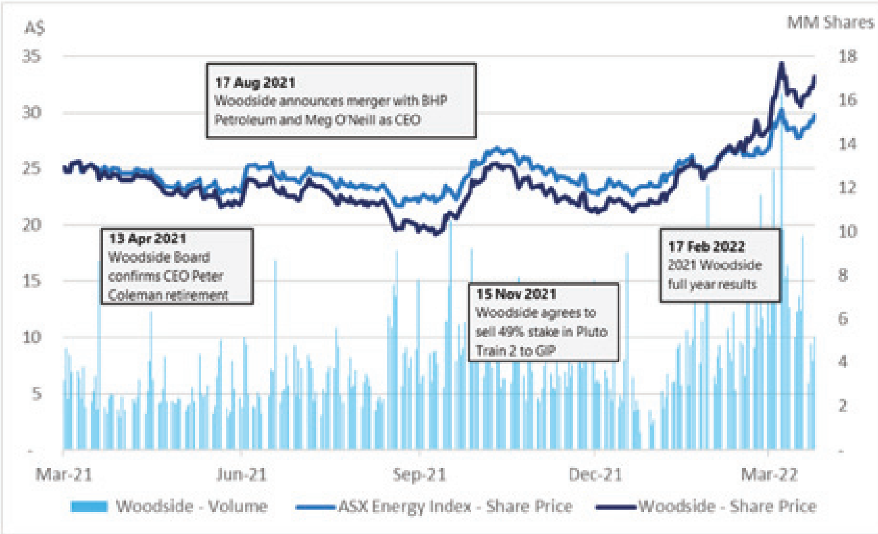
22 Seasonality

Woodside's revenue is exposed to commodity price fluctuations through the sale of hydrocarbons. Commodity pricing can be higher during winter in the Northern hemisphere due to increased demand.

23 Recent Share Price Performance

Outlined in the chart below is Woodside's (ASX:WPL) trading price performance since March 2021 relative to the performance of the S&P/ASX 200 Energy Index (ASX:XEJ).

Figure 8 – Woodside Share Price Performance since March 2021 (rebased to Woodside Share Price)



24 Substantial holdings

As at the Last Practicable Date, so far as known to Woodside, other than as set out below, there are no persons with "substantial holdings" (for the purposes of the Corporations Act) of Woodside Shares, being persons (and their associates) who, directly or indirectly, are interested in 5% or more of Woodside's voting shares. The table below also shows what these interests are expected to be on Admission, which will be following the issuance of the New Woodside Shares as part of Implementation.

	Woodside Shares Held (pre-Implementation)	% of issued capital (pre-Implementation)[1]	Anticipated Woodside Shares held (post-Implementation)	Anticipated % of issued capital (post-Implementation)[2]
Blackrock Group (Blackrock Inc. and subsidiaries)	57,411,550[3]	5.83	120,866,917[4]	6.37
State Street Corporation and subsidiaries	50,409,641[5]	5.12	91,004,737[6]	4.79[2 3]

None of the persons mentioned above have different voting rights to the other Shareholders.

1 Based on number of Woodside Shares on issue as at the Last Practicable Date.
2 Based on the estimated number of Woodside Shares on issue at Implementation being 1,898,749,771.
3 This information is derived from the Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 30 May 2019, indicating ownership of Woodside's shares as of such date.
4 This information is derived from the Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 30 May 2019, indicating ownership of Woodside's shares as of such date and a Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 31 January 2022, indicating ownership of BHP shares as of such date.
5 This information is derived from the Notice of Initial Substantial Holder filed by State Street Corporation with the ASX on 8 November 2021, indicating ownership of Woodside's shares as of such date.
6 This information is derived from the Notice of Initial Substantial Holder filed by State Street Corporation with the ASX on 8 November 2021, indicating ownership of Woodside's shares as of such date and information provided by BHP to Woodside dated 14 February 2022 relating to the number of shares held by State Street Corporation.

25 Financial information

Basis of presentation of Historical Financial Information

Woodside's audited consolidated financial statements included in Annexure 1 of this Prospectus have been prepared in accordance with Australian Accounting Standards and comply with IFRS. The financial statements have been prepared on a historical cost basis, except for derivative financial instruments and certain other financial assets and financial liabilities, which have been measured at fair value or amortised cost adjusted for changes in fair value attributable to the risks that are being hedged in effective hedge relationships.

If the carrying value of financial assets and financial liabilities does not approximate their fair value, the fair value has been included in the notes to the financial statements.

The financial statements comprise the financial results of the Woodside Group as at 31 December each year.

Subsidiaries are fully consolidated from the date on which control is obtained by the Woodside Group and cease to be consolidated from the date at which the Woodside Group ceases to have control.

The financial statements of subsidiaries are prepared for the same reporting period as the parent company, using consistent accounting policies. All intercompany balances and transactions, including unrealised profits and losses arising from intra-group transactions, have been eliminated in full.

The consolidated financial statements provide comparative information in respect of the previous period. Where required, a reclassification of items in the financial statements of the previous period has been made in accordance with the classification of items in the financial statements of the current period.

Non-controlling interests are allocated their share of the net profit after tax in the consolidated income statement and their share of other comprehensive income net of tax in the consolidated statement of comprehensive income and are presented within equity in the consolidated statement of financial position, separately from parent shareholders' equity.

Financial Arrangements

The following should be read in conjunction with the notes to the audited consolidated financial statements at Annexure 1 of Part 24 *(Woodside Historical Financial Information)* and Part 17 *(Operating and Financial Review of Woodside*) of this Prospectus.

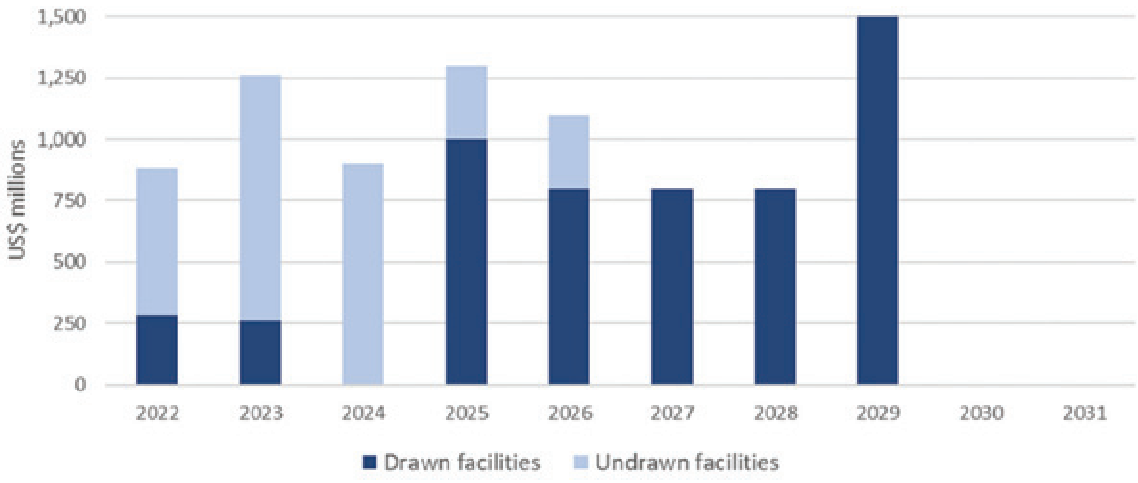
Liquidity

As at 31 December 2021, Woodside ended the period with liquidity of US$6,125 million which consisted of US$3,025 million cash and US$3,100 million in committed undrawn loan facilities.

Maturity profile of interest-bearing liabilities

Woodside's debt maturity profile as at 31 December 2021 is illustrated in Figure 9. The debt maturities below are based on contractual agreements as at 31 December 2021. All undrawn facilities are committed facilities. Further detail is provided below.

Figure 9



Bilateral facilities

Woodside had 14 bilateral loan facilities totalling US$1,900 million (as at 31 December 2021). Details of the bilateral loan facilities at the reporting date are as follows:

	As at 31 December 2021 (US$ millions)	
	Facility Amount	**Drawn Amount**
Short-term Maturity (Maturity within 12Mths)	200	nil
Medium-term Maturity (Maturity >12Mths<36Mths)	1,100	nil
Longer-term Maturity (Maturity >36Mths)	600	nil

Interest rates are based on US$ LIBOR plus an agreed margin and are fixed at the commencement of the drawdown period. Interest is paid at the end of the drawdown period. Woodside's is closely monitoring the market and the output from the various industry working groups managing the transition to new benchmark interest rates. Woodside is assessing the implications of the Interbank Offered Rates (IBOR) reform across Woodside and will manage and execute the transition from current benchmark rates to an alternative benchmark rate.

Syndicated facilities

On 3 July 2015, Woodside executed an unsecured US$1,000 million committed syndicated loan facility, which was increased to US$1,200 million on 22 March 2016 and amended to US$800 million on 15 November 2017. On 14 October 2019, Woodside increased the existing facility to US$1,200 million, with US$400 million expiring on 11 October 2022 and US$800 million expiring on 11 October 2024. Interest rates are based on US$ LIBOR plus an agreed margin and are fixed at the commencement of the drawdown period.

On 17 January 2020, Woodside completed a new US$600 million syndicated term loan facility. The facility is fully drawn with no amortisation and bullet repayment at maturity. The interest rate has been fixed as at 17 January 2020.

Details of syndicated loan facilities at the reporting date are as follows:

	As at 31 December 2021 (US$ millions)	
	Facility Amount	**Drawn Amount**
Syndicated Loan Facility		
Tranche A – Maturity 11 October 2022	400	nil
Tranche B – Maturity 11 October 2024	800	nil
Syndicated Term Loan Facility		
Maturity 17 January 2027	600	600

Japan Bank for International Cooperation (JBIC) Facility

On 24 June 2008, Woodside entered into a two-tranche committed loan facility of US$1,000 million and US$500 million respectively with JBIC. The US$500 million tranche was repaid in 2013. There is a prepayment option for the remaining balance. Interest rates are based on US$ LIBOR plus an agreed margin Interest is payable semi-annually in arrears and the principal amortises on a straight-line basis, with equal instalments of principal due on each interest payment date (every six months). The outstanding balance of the JBIC facility as at 30 June 2021 was US$208 million. The maturity date is 7 July 2023.

Under this facility, 90% of the receivables from designated Pluto LNG sale and purchase agreements are secured in favour of the lenders through a trust structure, with a required reserve amount of US$30 million. To the extent that this reserve amount remains fully funded and no default notice or acceleration notice has been given, the revenue from Pluto LNG continues to flow directly to Woodside from the trust account.

Medium Term Notes

On 28 August 2015, Woodside established a US$3,000 million Global Medium Term Notes Programme listed on the Singapore Stock Exchange. Three notes issued under this programme were outstanding as at 31 December 2021.

Maturity date	Currency	Carrying amount (millions)	Nominal interest rate
15 July 2022	US$	200	Floating US$ LIBOR + 2.21%
11 December 2023	CHF	175	Fixed 1.00% coupon
29 January 2027	US$	200	Fixed 3.07% coupon

The unutilised programme is not considered to be an available facility for the purposes of liquidity calculations

Unsecured bonds

Woodside had four fixed coupon unsecured US$ bonds issued in the U.S. debt capital markets outstanding as at 31 December 2021. Interest on the bonds is payable semi-annually in arrears. A summary of the terms of the indenture under which these unsecured bonds were issued is set out in paragraph 17 of Part 21 *(Additional Information)* of this Prospectus.

Maturity date	Carrying amount US$ millions	Fixed Coupon
5 March 2025	1,000	3.65%
15 September 2026	800	3.70%
15 March 2028	800	3.70%
4 March 2029	1,500	4.50%

Hedging

Woodside's financial position and performance are affected by changes in crude oil prices and variations in the exchange rates of various currencies (predominately of the Australian dollar to the U.S. dollar) and in U.S. interest rates. Where appropriate, Woodside uses derivative financial instruments such as swaps, options, futures and forward contracts, to hedge its risks associated with commodity prices, interest rates and foreign currency fluctuations.

Currently, Woodside may manage its commodity price risk exposure by hedging up to 50% of oil-linked exposure from produced hydrocarbons to 31 December 2023. In addition, certain derivative financial instruments may be used to hedge pricing risk within Woodside's trading portfolio.

As at the Last Practicable Date, Woodside had hedged:

- approximately 16.2 MMboe of 2022 of oil exposed production at an average price of US$74.65 per barrel; and
- approximately 21.8 MMboe of 2023 oil exposed production at an average price of US$74.50 per barrel.

In addition, Woodside has taken hedges on Corpus Christi volumes for 2022 and 2023. As a result of hedging and term sales, approximately 97% of Corpus Christi volumes in 2022 and 73% in 2023 have reduced pricing risk as at the Last Practicable Date.

In July 2016, Woodside issued CHF175 million in senior unsecured notes under its Global Medium Term Notes Programme. Associated with this issuance, Woodside entered into arrangements with a number of counterparties whereby the CHF proceeds were swapped to U.S. dollars, and the CHF fixed interest coupon payments were swapped to floating rate U.S. dollar obligations based on US$ LIBOR.

In January 2020 Woodside entered into a US$600 million fully drawn syndicated term facility. Associated with this facility, Woodside entered into arrangements with a number of counterparties whereby the US$ floating interest rate was swapped to a fixed US$ interest rate over the term of the facility.

In December 2021, Woodside completed an FX hedge programme to manage A$ FX exposure within the Scarborough and Pluto Train 2 developments. Woodside entered into arrangements with a number of counterparties whereby certain amounts of A$ were purchased under Forward arrangements between 2022 and 2025. In March 2022, Woodside purchased an amount of A$ under forward arrangements to manage short term A$ FX exposure relating to operating expenditures in 2022.

Current summary of hedge book

Commodity Hedge Book as at the Last Practicable Date		
Oil	BBls Volume (Net Short)	
	2022	16,200,000
	2023	21,840,000
TTF	MMBtu Volume (Net Short)	
	2022	18,452,502
	2023	30,930,000
HH	MMBtu Volume (Net Long)	
	2022	25,288,000
	2023	36,810,000

Interest Rate and Foreign Currency Hedge Book as at the Last Practicable Date		
Interest Rate Swap	Notional	Rate
17 January 2027	US$600 million	Receive 3Mth LIBOR
		Pay 1.72% Fixed
Cross Currency Swap	Notional	Rate
11-Dec-23	CHF175 million	Receive 1.00% Fixed
	US$179 million	Pay 3Mth LIBOR + 2.80%

Foreign Currency Hedge Book as at 31 January 2022		
A$ FX Forwards	Notional	Average Rate (AUD/USD)
2022 – 2023	A$790 million	0.71
2024 – 2025	A$417 million	0.71

More details can be found in the Notes to Financial Statements in Annexure 1 of Part 24 *(Woodside Historical Financial Information)* of this Prospectus.

Dividends

The Woodside Board has responsibility for approving dividends. The Woodside Board has determined there is no change to Woodside's dividend policy of a minimum of 50% of net profit after tax excluding non-recurring items in dividends. The Woodside Board's dividend pay-out ratio target is between 50% to 80% of net profit after tax, excluding non-recurring items, subject to market conditions and investment requirements.

Generally, Woodside pays dividends to its shareholders semi-annually, once in March or April and again in September or October of each year. Woodside maintains a dividend reinvestment plan that, if utilised by the Woodside Board, provides Woodside Shareholders with the option of reinvesting all or part of their dividends in additional Woodside Shares rather than taking cash dividends.

On 17 February 2022, the Woodside Board declared a final dividend of US$1,018 million to Woodside Shareholders (US$1.05 per Woodside Share), representing a pay-out ratio of approximately 80% of net profit after tax excluding non-recurring items. The dividend reinvestment plan remains active, allowing eligible Woodside Shareholders to reinvest their dividends directly into Woodside Shares at a 1.5% discount. Woodside's prior dividends for the years ended 31 December 2015, 2016, 2017, 2018, 2019, 2020 and 2021 are as follows:[20]

Date Declared	Date Paid	Type of Dividend	Dividend per Share	Total Dividends
18 February 2015	25 March 2015	Final	US$1.44	US$1,186 million
19 August 2015	23 September 2015	Interim	US$0.66	US$544 million
17 February 2016	8 April 2016	Final	US$0.43	US$354 million
19 August 2016	30 September 2016	Interim	US$0.34	US$286 million
22 February 2017	29 March 2017	Final	US$0.49	US$413 million
16 August 2017	21 September 2017	Interim	US$0.49	US$413 million
14 February 2018	20 March 2018	Final	US$0.49	US$413 million
15 August 2018	20 September 2018	Interim	US$0.53	US$496 million
14 February 2019	20 March 2019	Final	US$0.91	US$852 million
15 August 2019	20 September 2019	Interim	US$0.36	US$337 million
13 February 2020	20 March 2020	Final	US$0.55	US$518 million
13 August 2020	18 September 2020	Interim	US$0.26	US$248 million
18 February 2021	24 March 2021	Final	US$0.12	US$115 million
18 August 2021	24 September 2021	Interim	US$0.30	US$289 million
17 February 2022	23 March 2022	Final	US$1.05	US$1,018 million

[20] Dividends per share are calculated by dividing Woodside's dividends paid by the number of ordinary shares outstanding.

Part 8 – Overview of BHP Petroleum

1 Overview

1.1 BHP Group Overview

Incorporated in 1885, BHP is a leading global resources company with a market capitalisation of approximately A$250 billion as of 24 March 2022 (based on the closing price of BHP Shares of A$49.30). BHP's operations revolve around the discovery, development, production and marketing of iron ore, metallurgical coal, copper, nickel and uranium. BHP also has substantial interests in potash, and, through BHP Petroleum, oil and gas.

BHP is headquartered in Melbourne, Australia, with more than 80,000 employees and contractors, operating in over 90 locations worldwide. BHP Group Limited is registered in Australia with its registered office at 171 Collins Street, Melbourne, Victoria 3000, Australia.

1.2 BHP Petroleum Overview

BHP pioneered the development of an oil and gas industry in Australia with the Bass Strait discovery in 1965. BHP Petroleum International Pty Ltd is a wholly owned subsidiary of BHP. The BHP Petroleum business now has conventional oil and gas assets located in the U.S. GOM, Australia, T&T, Algeria and Mexico, and appraisal and exploration options in T&T, central and western U.S. GOM, Eastern Canada, Barbados and Egypt. The crude oil and condensate, gas and NGLs produced by the assets of BHP Petroleum are sold on the international spot and domestic markets. The BHP Petroleum assets include BHP Petroleum's effective interest in the Rhourde Ouled Integrated Development ("**Algerian Assets**"), which BHP is in the process of divesting.

During FY2021, BHP Petroleum achieved first production at two major development projects, both of which were delivered on or ahead of schedule. The Ruby oil and gas project in T&T achieved first production in May 2021. The Atlantis Phase 3 project achieved first production in the first half of the 2021 financial year. Total BHP Petroleum production and unit costs for FY2021 was 103 MMboe and US$10.83/boe respectively. The calculation of BHP Petroleum unit costs is set out in Part 18 (*Operating and Financial Review of BHP Petroleum*). BHP Petroleum unit costs are calculated as ratio of net costs of the assets to the equity share of production. BHP Petroleum unit costs exclude freight, exploration and development and evaluation expense and other costs that do not represent underlying cost performance of the business.

2 Assets

2.1 Overview of Assets

BHP Petroleum has an international portfolio of assets which includes oil and gas production in the U.S. GOM, Australian LNG, oil and domestic gas assets and T&T oil and domestic gas assets. Key growth in the portfolio is driven by sanctioned and unsanctioned developments to currently producing assets in the U.S. GOM as well as the development of the Scarborough field in Australia.

Producing and Post-FID Assets as at 31 December 2021[21]

Asset	Description	Operator	BHP Petroleum participating interest	2021 Prod.[22] MMboe
Greater Shenzi[23]	Offshore oil and gas asset located in U.S. GOM. Recently, BHP approved the brownfield expansion of Shenzi via the Shenzi North Project.	BHP Petroleum	72%	9.4
Atlantis	Offshore oil assets located in the U.S. GOM.	BP	44%	13.9
Mad Dog	Offshore oil asset located in the U.S. GOM. Phase 2 expansion of the project is currently underway.	BP	23.9%	4.9
North West Shelf	LNG facility processing gas and condensate from the offshore North Rankin and Goodwyn-A offshore platforms. Onshore facilities include 5 LNG trains with 16.9 Mtpa export capacity, condensate trains and a domestic gas plant.	Woodside	16.67%[24]	22.7
Bass Strait	Southeast Australian major integrated oil and gas asset consisting of offshore facilities, onshore plants and associated pipeline infrastructure.	Exxon Mobil	Gippsland Basin Joint Venture (GBJV): 50.0% Kipper Unit Joint Venture (KUJV): 32.5%	29.2
Pyrenees	Northwest Australian offshore oil asset facility consisting of FPSO	BHP Petroleum	WA-42-L permit: 71.43% WA-43-L permit: 39.999%	2.8
Macedon	Northwest Australian offshore gas asset with the gas piped to an onshore processing plant.	BHP Petroleum	71.43%	8.4
Scarborough	Western Australian offshore gas development exporting gas from a floating production unit to Pluto LNG facility for onshore processing.	Woodside	26.5%	FID announced 22 November 2021 Targeting first cargo in 2026
T&T (Angostura and Ruby)	Angostura: Offshore oil and gas asset located northeast of Trinidad Ruby: Offshore oil and gas asset located northeast of Trinidad, tied into Angostura infrastructure	BHP Petroleum	45.0% Block 2(c) 68.46% effective interest in Block 3(a) Project Ruby	10.6

21 Includes all actively producing sanctioned and brownfield projects.

22 Production attributable to BHP Petroleum's participating interest in the relevant Asset for the 12 months ended 31 December 2021.

23 Includes Shenzi and Shenzi North (72% interest) & Wildling (100% interest, pre-FID).

24 North West Shelf LNG Ownership is 12.5-16.67% across 9 separate joint venture agreements, see paragraph 4 of Part 7 (*Overview of Woodside*) for further detail. This range does not include BHP Petroleum's interest in the historic "Domestic Gas Joint Venture" which is 8.33%.

Projects and Growth Options					
Asset	**Description**	**Operator**	**BHP Petroleum participating interest**	**Target FID**	**Target First Prod**
Trion	Greenfield development in the deepwater Mexico Gulf of Mexico.	BHP Petroleum	60%	2022	2026
Calypso	Deepwater gas discovery in T&T North	BHP Petroleum	70%	2026	2027-2028
Magellan	Deepwater gas discovery in T&T South	BHP Petroleum	65%	—	—

2.2 Producing Assets

1. Shenzi

Shenzi overview and history

The Shenzi conventional oil and gas field is located approximately 195km off the coast of Louisiana in the Green Canyon protraction area, Gulf of Mexico. The field has produced ~350 MMboe (100% basis) since production commenced in 2009. Crude oil produced from the field is transported to connecting pipelines for onward sale to Gulf coast customers. Natural gas production is transported via a lateral pipeline that is tied-in into the Cleopatra natural gas pipeline for ultimate transmission onshore to the Neptune processing plant in St. Mary's Parish, Louisiana.

The Shenzi joint venture has recently sanctioned two brownfield developments. First, a subsea multiphase pumping project to increase production rates from existing wells, which is targeted to be completed in 2022. The other sanctioned project involves sidetracks of existing M9U production wells to access unswept oil in the M9U reservoir and achieved first oil in the fourth quarter of 2021. There are also additional unsanctioned infill opportunities at Shenzi to increase production with 3 producing and 2 water injection wells tied back to the Shenzi tension leg platform.

In addition to the currently producing Shenzi field, the project also includes the future tie-back developments of Shenzi North and Wildling, which will take advantage of existing infrastructure and production capacity in the nearby Shenzi production facility. Shenzi North, the first development phase of the Greater Wildling mini-basin, was discovered in 2017. On 5 August 2021, BHP approved the funding of US$544 million in capital expenditure (100% basis) to execute the Shenzi North oil project in the U.S. GOM. The project is expected to add two wells and subsea equipment to establish a new drill centre north of Shenzi. Production is expected to begin in FY2024.

The Wildling project adds an additional two wells and subsea equipment. The Wildling field, which is also located in the Wildling-mini basin was discovered in 2017 and is expected to be developed as a subsea tie-back to the Shenzi tension leg platform. Potential FID is expected in 2022-2023, which would lead to first production in 2024-2025.

Ownership structure and joint ventures

The Shenzi field covers lease blocks GC609, GC610, GC652, GC653 and GC654. On 6 November 2020, BHP finalised a membership interest purchase and sale agreement with Hess to acquire an additional 28% working interest in Shenzi, taking its working interest from 44% to 72%. Repsol is the only other participant in the Shenzi joint venture, with a 28% working interest.

Shenzi North lies in lease blocks GC608 and GC609. The ownership is 72% BHP Petroleum and 28% Repsol.

Greater Wildling lies in lease blocks GC520 and GC564. Greater Wildling is 100% BHP Petroleum owned and operated.

BHP Petroleum owns a 25% and 22% interest respectively in the companies that own and operate the Caesar oil pipeline and the Cleopatra natural gas pipeline which connect the Green Canyon area to connecting pipelines that transport the product onshore.

Figure 10 – Shenzi Project map[25]

Offshore infrastructure

Shenzi Tension Leg Platform	
Location	195km off the coast of Louisiana (United States) in the Green Canyon protraction area, Gulf of Mexico
Facility type	Tension leg platform
Fields (discovered (approximate))	Shenzi (2002), Greater Wilding (2017), which includes Shenzi North development
Product	Oil and gas
Production capacity	Oil: 100,000 bbl/d Gas: 50 MMscf/d
First production	2009
Production wells (current / current and sanctioned)	18 / 21

2. Atlantis

Atlantis overview and history

The Atlantis conventional oil and gas field is one of the largest producing fields in the U.S. GOM, located off the coast of Louisiana in the south-eastern Green Canyon protraction area. Oil and gas from the field is transported to existing shelf and onshore interconnections via the Caesar and Cleopatra pipelines.

Atlantis was discovered in 1998 and has produced approximately 460 MMboe (100% basis) since first production was achieved in 2007. The development of Atlantis occurred over several phases:

- **Phase 1**: sanctioned in 2003;
- **Phase 2**: Operator (BP) submitted Development Operations Coordination Document in 2009, targeting Atlantis North flank. Production commenced in 2009; and

[25] Shenzi Project map in relation to BHP Petroleum's U.S. GOM projects. Fields, blocks and pipelines shown in maps are stylised and not to scale. Map only shows BHP Petroleum fields, leases and pipelines which are referenced in this BHP Petroleum Overview Part of this Prospectus.

- **Phase 3**: sanctioned in 2019 with first production achieved in 2020, including eight subsea wells and associated manifolds and flow lines.

Atlantis possesses multiple unsanctioned projects currently in the planning phase, leveraging existing infrastructure and technology. Future development phases for Atlantis include multiple infill campaigns with a total of twelve additional producing wells and six additional water injection wells utilising existing infrastructure. In addition, a major facilities expansion is planned to include topsides modification, subsea multiphase pumping, and upgrades to water injection and water handling facilities.

Ownership structure and joint ventures

Atlantis field lies within lease blocks GC699, GC742, GC743, and GC744. It is owned by BP (56.0%, operator) and BHP Petroleum (44.0%).

Figure 11 – Atlantis Project map[26]

Offshore infrastructure

Atlantis Platform	
Location	~210 km off the coast of Louisiana (United States) in the south-eastern Green Canyon protraction area
Facility type	Semi-submersible wet tree development
Fields (discovered (approximate))	Atlantis (1998)
Product	Crude oil and natural gas
Production capacity	Oil: 200,000 bbl/d Gas: 180 MMscf/d
First production	2007
Production wells (current / current and sanctioned)	26 / 31

[26] Atlantis Project map in relation to BHP Petroleum's U.S. GOM projects. Fields, blocks and pipelines shown in maps are stylised and not to scale. Map only shows the BHP Petroleum fields, leases and pipelines which are referenced in this BHP Petroleum Overview Part of this Prospectus.

3. Mad Dog

Mad Dog overview and history

The Mad Dog conventional oil and gas field is located off the coast of Louisiana in the Green Canyon protraction area, Gulf of Mexico. Mad Dog was discovered in 1998 and has produced approximately 260 MMboe (100% basis) since first production, which was achieved in 2005.

Phase 1 of the project is processed through a subsea truss spar, Spar A. Oil from the project is transported to Ship Shoal 332B through the Caesar pipeline where it is then transported via the Cameron Highway Oil Pipeline System internally in the United States of America. Gas from the project is exported to Ship Shoal 332A through the Cleopatra pipeline, where it is then transported to the Manta Ray Gathering System and then to the Nautilus Gas Transportation System into Louisiana.

Mad Dog Phase 2, which was sanctioned in 2017 for US$2.2 billion in capital expenditure (BHP Petroleum share), focuses development on the southern flank of the field and is targeting first production in 2022. Mad Dog Phase 2 includes a new semi-submersible FPU platform named Argos. The development plan includes 14 production wells and eight water injectors (nine producers and four water injectors have been drilled to date). The new platform will be moored approximately 10km southwest of the existing Mad Dog platform.

Beyond the sanctioned projects, there are further brownfield growth opportunities at Mad Dog. There are additional opportunities to increase the Mad Dog Phase 2 production beyond the initial investment scope with 9 new wells tied back to existing facility. Additionally, there is potential for a water injection expansion at the project with two water injector wells providing water from Mad Dog Phase 2 facility to increase production at the existing Spar A facility.

Ownership structure and joint ventures

Mad Dog field lies in lease blocks GC738, GC781, GC782, GC824, GC825, GC826, GC868, GC869, and GC870. It is owned by BP (60.5%, operator), BHP Petroleum (23.9%), and Chevron (15.6%)

Figure 12 – Mad Dog Project map[27]

[27] Mad Dog Project map in relation to BHP Petroleum's U.S. GOM projects. Fields, blocks and pipelines shown in maps are stylised and not to scale. Map only shows the BHP Petroleum fields, leases and pipelines which are referenced in this BHP Petroleum Overview Part of this Prospectus.

Offshore infrastructure

Mad Dog Platforms	Phase 1 (A-Spar)	Phase 2 (Argos)
Location	200km off the coast of Louisiana (United States) in the south-eastern Green Canyon protraction area	
Facility type	Subsea truss spar	Semi-submersible floating production platform
Fields (discovered (approximate))	Mad Dog (1998)	
Product	Crude oil and gas	Crude oil and gas
Production capacity	Oil: 100,000 bbl/d Gas handling: 60 MMscf/d	Oil: 140,000 bbl/d Gas: 75 MMscf/d
First production	2005	Target first production in 2022
Production wells (current / current & sanctioned)	10 / 13 – 14	0 / 14

4. North West Shelf

Refer to paragraph 4 of Part 7 (*Overview of Woodside*) for an overview of North West Shelf assets. BHP Petroleum owns equity interests of between 12.5% and 16.67% in the various North West Shelf joint ventures operated by Woodside. This range does not include BHP Petroleum's interest in the historic "Domestic Gas Joint Venture" which is 8.33%.

5. Bass Strait

Bass Strait overview and history

The Bass Strait Project consists of numerous conventional oil and gas fields, in the well-established Gippsland Basin off the south-east coast of Victoria, Australia. The project consists of an integrated network of offshore platforms and subsea tie-backs connected via extensive pipeline infrastructure to onshore processing facilities at Longford and Long Island Point. Bass Strait was Australia's first major offshore oil and gas development and has sold over 8 Tcf of pipeline gas and over 4 billion bbl of oil since first production in 1969.

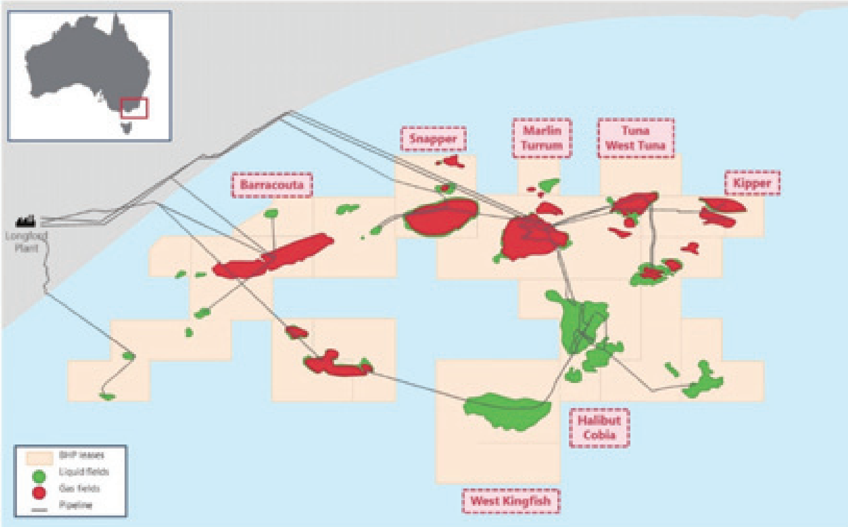
Natural gas production from Bass Strait currently supplies approximately 40% of Australian east coast domestic gas demand and is the largest supplier into the Eastern Australian domestic gas market, which spans Queensland, New South Wales, Victoria, Tasmania, Australian Capital Territory, Northern Territory, and South Australia. The asset also produces crude oil and condensate, LPG and ethane which is sold to both domestic and international customers.

The Longford facilities process both crude oil and natural gas to achieve requisite sales specifications. Natural gas is exported directly into the east coast gas network while crude and NGLs are transferred to the Long Island Point facility by pipeline. Crude is stored at Long Island Point prior to transfer to domestic refineries via pipeline or export customers via ship loading. NGLs are processed to produce butane, propane, and ethane products. Butane and propane are stored prior to onward sale via truck loading, pipeline, or export shipping. Ethane is sold via pipeline to a customer in the Altona petrochemical area.

In April 2021, the Gippsland Basin Joint Venture successfully commissioned the West Barracouta natural gas field with a capital investment of approximately A$400 million (100% share). Bass Strait retains a portfolio of contingent and prospective opportunities, primarily from deeper, acid gas resources with commercialisation enabled by the Longford Gas Conditioning Plant, commissioned in 2017, which provides acid gas processing capability. Further investment to deliver additional gas between 2023 and 2027 including additional development from the Kipper field and advancing funding decision for the Turrum field were announced in March 2022.

Several of the Bass Strait offshore facilities have ceased production following field depletion and an active programme of restoration is underway. Near term activities are dominated by well plug and abandonment with planning in progress for longer term facility decommissioning and removal.

Figure 13 – Bass Strait Project map[28]



Ownership structure and joint ventures

Bass Strait production is primarily from the Gippsland Basin Joint Venture owned by ExxonMobil (50%, operator) and BHP Petroleum (50%) and the Kipper Unit Joint Venture owned by ExxonMobil (32.5%, operator), BHP Petroleum (32.5%) and Mitsui (35%). Kipper unit production is processed by the Gippsland Basin Joint Venture under a processing agreement. The Gippsland Basin Joint Venture fields lie in permits Vic/L1-L11 and Vic/L13-19 and the Kipper field lies in permits Vic/L9 and Vic/L25.

Bass Strait key production hubs

Bass Strait hubs	Barracouta	Snapper	Marlin / Turrum	Tuna / West Tuna	Kipper	Oil Block
Location	Bass Strait off the south-east coast of Australia					
Facility type	Steel jacket platform and West Barracouta subsea tieback	Steel jacket platform	Steel jacket platform	Steel jacket platform and concrete gravity structure	Subsea tieback to West Tuna	Steel jacket platform
Fields (discovered (approximate))	Barracouta (1965)	Snapper (1968)	Marlin (1966)	Tuna (1968)	Kipper (1986)	Cobia (1967), Halibut (1967), West Kingfish (1977)
Product	Natural gas, Natural gas liquids (Condensate and LPG) and Crude Oil					
Production capacity	Processing via onshore gas plants at Longford and Long Island Point: Gas: 1,040 TJ/day Crude oil and condensate: 65,000 bbl/d Liquefied petroleum gas: 5,150 tonnes /d Ethane: 850 tonnes/d					
First production	1969	1981	1970	1979	2017	1970
Active production wells (Note: no future drill wells currently sanctioned)	9	23	15	65	2	58

[28] Bass Strait Project map. Fields, blocks and pipelines shown in maps are stylised and not to scale. Map only shows the key BHP Petroleum fields, leases and pipelines which are referenced in this BHP Petroleum Overview Part of this Prospectus.

6. Pyrenees

Pyrenees overview and history

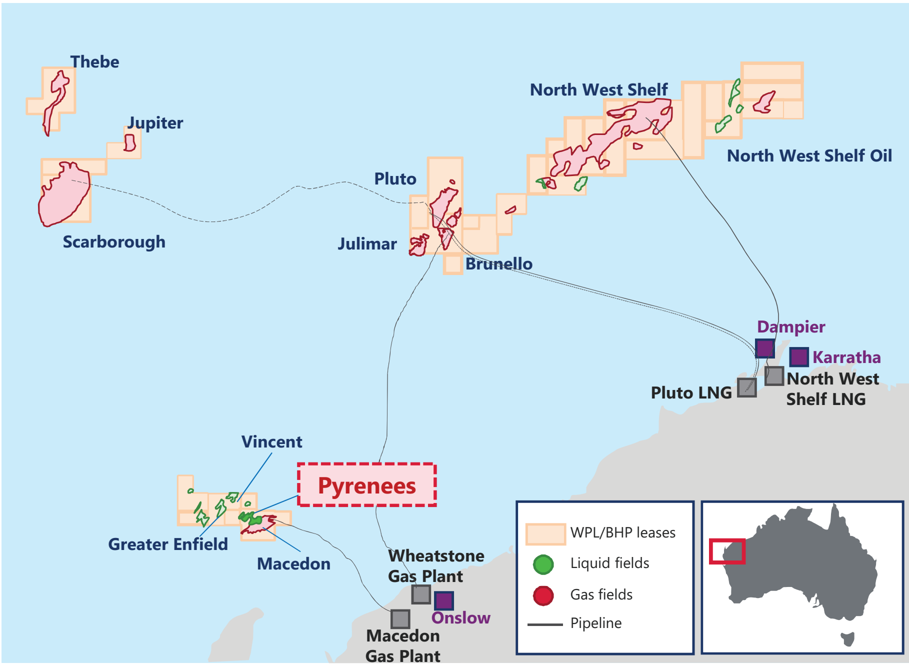
The Pyrenees project consists of 6 conventional oil fields located approximately 45km northwest of Exmouth, Western Australia, in the Carnarvon Basin. Crude oil is offloaded from the FPSO directly to tankers for sale to international markets and attracts a premium to Brent given its low sulphur content. Produced formation water is treated on the facility and reinjected for disposal in four subsea water injection wells. A single well into the Macedon gas field allows for injection or production of natural gas depending on facility requirements.

The Pyrenees Phase 4 project has been sanctioned with infill drilling and well intervention for water shut-off.

Ownership structure and joint ventures

The Pyrenees development covers two separate production licences: WA-42-L is owned by BHP Petroleum (71.4%, operator) and Santos (28.6%). WA-43-L is owned by BHP Petroleum (40%, operator), Santos (31.5%) and Inpex (28.5%).

Figure 14 – Pyrenees Project map[29]



[29] Pyrenees Project Map in relation to BHP Petroleum's and Woodside's Western Australia projects. Fields, blocks and pipelines shown in maps are stylised and not to scale with the intent to show the general location and proximity of BHP Petroleum's and Woodside's Carnarvon Basin fields assets. Maps only show the key Woodside and BHP Petroleum fields, leases and pipelines which are referenced in the Woodside and BHP Petroleum overview parts of this Prospectus.

Offshore infrastructure

Pyrenees	
Location	45km north west of Exmouth, Western Australia
Facility type	Floating production, storage and offloading facility (Pyrenees Venture)
Fields (discovered (approximate))	Ravensworth (2003), Crosby (2003), Stickle (2004), Wildbull (2004), Tanglehead (2004) and Moondyne (1993)
Product	Crude oil
Production capacity	Oil: 96,000 bbl/d
First production	2010
Production wells (current / current and sanctioned)	22 / 22 † ‡

Note: † includes one gas well drilled into the Macedon field. ‡ Pyrenees Phase 4 is sanctioned on the basis of well re-entry for infill drilling and water shutoff and so therefore will not add to well count.

7. Macedon

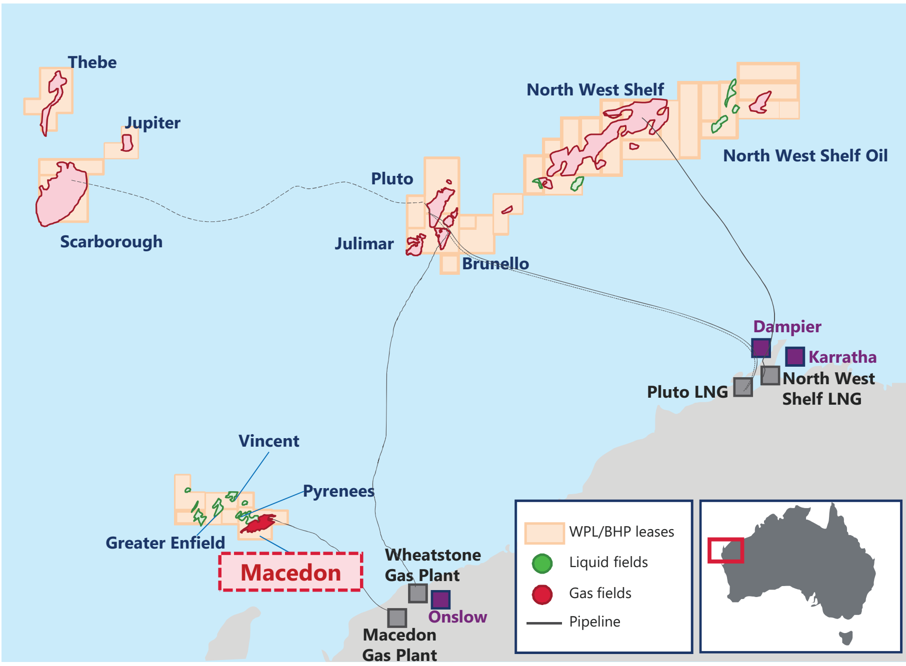
Macedon overview and history

Macedon is an offshore gas field located in the Exmouth sub-basin around 40km north of Exmouth, Western Australia. Gas is produced from subsea wells and flows through a pipeline to a gas treatment plant located near Onslow. Sales quality gas is then transported via a dedicated 67km pipeline into the Dampier to Bunbury Natural Gas Pipeline and thereon for onward sale into the Western Australian domestic gas market.

Ownership structure and joint ventures

Macedon lies within WA-42-L, the same production licence as Pyrenees. It is owned by BHP Petroleum (71.4%, operator) and Santos (28.6%).

Figure 15 – Macedon Project map[30]



30 Macedon Project map in relation to BHP Petroleum's and Woodside's Western Australia projects. Fields, blocks and pipelines shown in maps are stylised and not to scale with the intent to show the general location and proximity of BHP Petroleum's and Woodside's Carnarvon Basin assets. Map only shows the key Woodside and BHP Petroleum fields, leases and pipelines which are referenced in the Woodside and BHP Petroleum Overview Parts of this Prospectus.

Offshore infrastructure

Macedon	
Location	100km offshore west of Onslow, Western Australia
Facility type	Onshore single-train gas plant
Fields (discovered (approximate))	Macedon (1992)
Product	Natural gas and condensate
Production capacity	Gas: 213 MMscf/d Condensate: 110 bbl/d
First production	2013
Production wells (current / current & sanctioned)	4 / 4 †

Note: † excludes one Macedon gas well drilled as part of the Pyrenees development

8. Trinidad and Tobago

Angostura and Ruby overview and history

The Greater Angostura field is an offshore conventional oil and gas field located 38km northeast of Trinidad. The Angostura field was discovered in 1999, with first oil achieved in January 2005 (Phase 1). Phase 2 established gas sales in 2011. First gas for Angostura Phase 3 was established in September 2016. Ruby is a conventional offshore oil and gas field located within the Greater Angostura Fields. First oil was achieved in May 2021.

The current development comprises a main central processing platform ("**CPP**"), gas export platform ("**GEP**"), four wellhead protector platforms ("**WPP**") and onshore terminal. Flowlines connect the Ruby wellhead platform back to the CPP and GEP for processing.

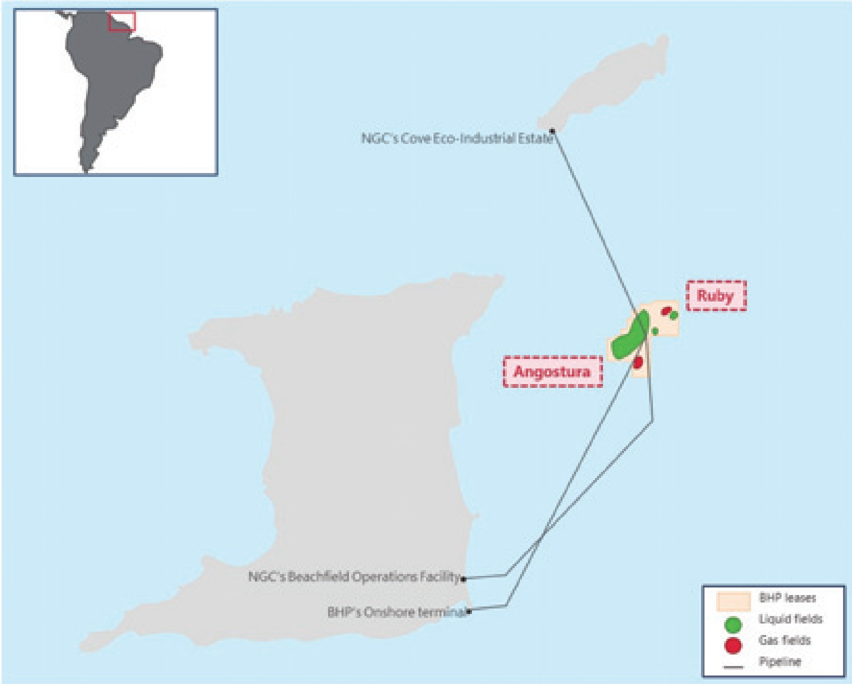
Crude oil from CPP is transported to the terminal facility located in the south eastern end of Trinidad. Calypso crude from the Angostura and Ruby fields is sold on a spot basis to international markets via the terminal facility while the gas is sold domestically under term contracts via separate pipelines to T&T from the Gas Export platform.

Ownership structure and joint ventures

The Angostura field lies in Block 2c. It is owned by BHP Petroleum (45.0%, operator), National Gas Company (30.0%) and Chaoyang (25.0%).

The Ruby field lies in Block 3a. It is owned by BHP Petroleum (68.46%, operator) and National Gas Company (31.54%).

Figure 16 – Angostura and Ruby Project map[31]



Offshore infrastructure

Trinidad and Tobago	Angostura – Block 2(c)	Ruby – Block 3(a)
Location	38.5km north-east of Trinidad	
Facility type	1 CPP, 1 GEP, 4 WPP	1 WPP
Fields (discovered (approximate))	Angostura (1999)	Ruby (2006)
Product	Oil and Gas	Oil and Gas
Production capacity	Oil: 100,000 bbl/d Gas: 340 MMscf/d	Tie-in to Angostura infrastructure Oil: 16,000 bbl/d Gas: 80 MMscf/d
First production	2005	2021
Production wells (current / current and sanctioned)	22 / 22	5 / 5
Injection wells (current / current and sanctioned)	7 / 7	1/1

9. Scarborough

Refer to paragraph 7 of Part 7 (*Overview of Woodside*) of this Prospectus for the Scarborough asset overview. BHP Petroleum owns a 26.5% participating interest in the Scarborough Joint Venture.

10. Other

BHP Petroleum is operator for several Australian fields that are no longer in production including Griffin (45-71.43% Equity) and Stybarrow (50%) offshore oil fields located off North West Cape and the Minerva offshore gas field (Operator 90%) in the Otway basin. A programme of restoration activities is underway and is being carried out in close cooperation with environment and safety regulators and other key stakeholders.

31 Angostura and Ruby Project map. Fields, blocks and pipelines shown in maps are stylised and not to scale. Map only shows the key BHP Petroleum fields, leases and pipelines which are referenced in this BHP Petroleum Overview Part of this Prospectus.

11. Algerian Assets Sale

While BHP Petroleum's reserves and resources as of 30 June 2021 and the combined financial statements of BHP Petroleum are inclusive of BHP Petroleum's 28.85% interest in the Algerian Assets, these assets are currently classified as non-core and are expected to be divested prior to the Implementation of the Merger.

As part of the Merger, Woodside and BHP have agreed that BHP will retain the economic benefits of the Algerian Assets from the Merger effective date (1 July 2021), including the net proceeds from the divestment. If the divestment of the Algerian Assets has not completed prior to the Implementation of the Merger, Woodside will operate the Algerian Assets on behalf of BHP under an arrangement whereby BHP will retain all economic exposure and indemnify Woodside for any costs and liabilities associated with the Algerian Assets until such time as both parties agree alternative arrangements or the Algerian Assets lapse or terminate (whichever is earlier). As of 30 June 2021, the 1P reserves of the Algerian Assets were approximately 8.9 MMboe and the Algerian Assets contributed revenues of US$164m, US$159m and US$258m for the financial years ended 30 June 2021, 2020 and 2019, respectively.

2.3 Seasonality

BHP Petroleum's revenue is exposed to commodity price fluctuations through the sale of hydrocarbons. Commodity pricing can be higher during winter in the Northern hemisphere due to increased demand.

2.4 Description of Property

The following table sets out the location, capacity and BHP Petroleum's ownership interest in the assets described below.

Asset	Location	BHP Petroleum interest (%)	100% capacity	BHP Petroleum operated
Shenzi (Green Canyon 653)	U.S. GOM	72.0%	100 kbbl/d oil 50 MMscf/d gas	Yes
Atlantis (Green Canyon 743)	U.S. GOM	44.0%	200 kbbl/d oil 180 MMscf/d gas	No
Mad Dog (Green Canyon 782)	U.S. GOM	23.9%	A-Spar (Phase 1): 100 kbbl/d oil 60 MMscf/d gas handling Argos (Phase 2): 140 kbbl/d oil 75 MMscf/d gas	No
Bass Strait	Offshore and onshore Victoria	Gippsland Basin joint venture: 50.0% Kipper Unit joint venture: 32.5%	65 kbbl/d oil 1,040 TJ/d 5,150 tpd LPG 850 tpd Ethane	No
North West Shelf LNG	Refer to Woodside Description of Property – paragraph 4 of Part 7 *(Overview of Woodside)* of this Prospectus. BHP Petroleum owns an equivalent participating interest to Woodside but is not operator			
North West Shelf Oil (Okha FPSO)	Refer to Woodside Description of Property – paragraph 4 of Part 7 *(Overview of Woodside)* of this Prospectus. BHP Petroleum owns a non-operated 16.67% participating interest			
Pyrenees	Offshore Western Australia	WA-42-L permit: BHP Petroleum 71.43% WA-43-L permit: BHP Petroleum 39.999%	Production capacity: 96 kbbl/d oil Storage: 920 kbbl	Yes
Macedon	Offshore and onshore Western Australia	71.43%	Production capacity: 213 MMscf/d gas, 0.02 kbbl/d condensate	Yes
Greater Angostura	Offshore T&T	45.0%	100 kbbl/d oil 340 MMscf/d gas	Yes
Ruby	Offshore T&T	68.46%	16 kbbl/d oil 80 MMscf/d gas	Yes

In addition to the assets described above, BHP Petroleum leases office space in several locations globally, the two largest being Houston, Texas and Port of Spain, Trinidad.

3 Recent Performance

BHP Petroleum Financial and Key Operating Information				
US$ million	**HY Dec 2021**	**FY June 2021**	**FY June 2020**	**FY June 2019**
Revenue	3,198	3,909	3,997	5,867
Underlying EBITDA[32]	2,870	2,238	2,164	4,061
Profit/(loss) after taxation from Continuing Operations	583	(361)	(178)	661
Profit/(loss) after taxation from Continuing and Discontinuing operations	583	(361)	(178)	326
Cash generated from operations	1,980	1,743	1,925	3,693
Dividends distributed	N/A	N/A	N/A	N/A
Key ratios				
Effective income tax rate (%)	N/A	N/A	N/A	N/A
Earnings (US cps)	N/A	N/A	N/A	N/A
Gearing (%)	N/A	N/A	N/A	N/A
Production volumes				
Gas (Bcf)	168.5	340.6	359.6	396.9
Liquids (MMboe)	25.1	46.0	48.9	55.1
Total (MMboe)	53	103	109	121

During FY2021, BHP Petroleum acquired an additional 28% working interest in Shenzi for US$0.5 billion, increasing its share from 44% to 72% of the project. In FY2019, BHP Petroleum completed the divestment of its U.S. Onshore Shale business, realising net proceeds on sale of US$10.4 billion.

Further details of BHP Petroleum's historic capital expenditure and divestments is included in Part 18 *(Operating and Financial Review of BHP Petroleum)* of this Prospectus.

4 Growth Projects

1. Trion

Trion overview and history

The Trion project (Trion) is a BHP Petroleum-operated oil and gas opportunity in Mexico, which was discovered by PEMEX (Mexico's state-owned petroleum company) in 2012, with BHP acquiring operatorship in 2017.

Trion is a greenfield development that would represent the first oil production from Mexico's deepwater, with potential for future discoveries to be tied back to Trion facilities. The Trion field is in the Perdido Foldbelt, Gulf of Mexico, at a water depth of 2,500m approximately 180km off the Mexican coastline and 30km south of the U.S./Mexico maritime border.

Ownership structure and joint ventures

BHP Petroleum holds a 60% participating interest in and operatorship of blocks AE-0092 and AE-0093 containing the Trion discovery located in the deep-water Gulf of Mexico offshore Mexico. PEMEX Exploration & Production Mexico holds a 40% interest in the blocks.

2. Calypso

Calypso overview and history

Calypso is a BHP Petroleum-operated deepwater gas discovery in T&T. The Calypso opportunity is located 217km off the coast of T&T and comprises several discoveries in deepwater Blocks 23(a) and TTDAA 14. Calypso is proximate to existing LNG infrastructure and downstream petrochemical facilities.

[32] These are non-IFRS measures that are unaudited but derived from audited Financial Statements. These measures are presented to provide further insight into BHP Petroleum's performance.

The Calypso appraisal drilling program (consisting of the Bongos-3, Bongos-3X and Bongos-4 wells) concluded on 20 December 2021. All wells encountered hydrocarbons. Bongos-3 confirmed volumes downdip of prior penetrations and Bongos-4 established volumes in a new segment. The well results are currently under evaluation and will be incorporated into the development plan.

Ownership structure and joint ventures

Calypso sits within the Deepwater Blocks 23(a) and TTDAA 14 lease blocks. It is owned by BHP Petroleum (70%, operator) and BP (30%).

3. Magellan

Magellan overview and history

The Magellan discoveries in the Trinidad South Deepwater licence block TTDAA 5 includes the LeClerc and Victoria gas fields discovered in 2016 and 2018, respectively. Both fields are approximately 200 km east of the island of Trinidad in water depths of approximately 1,800m.

Ownership structure and joint ventures

BHP Petroleum signed a Production Sharing Contract in 2013 for exploration in the TTDAA 5 Block, BHP Petroleum is operator and has a 65% working interest with Shell as partner.

5 Summary of reserves and resources determined by the Competent Person

BHP Petroleum's Net Reserves as at 31 December 2021

Country	Asset	Oil and Condensate Reserves (MMbbl)		Gas Reserves (Bcf)	
		1P	2P	1P	2P
Australia	Bass Strait	10.6	17.9	490.0	829.8
	NWS	19.2	24.9	717.8	940.0
	Pyrenees	10.0	19.0	0.0	0.0
	Macedon	0.0	0.0	239.0	308.4
	Scarborough	0.0	0.0	1,944.9	3,031.6
U.S. GOM	Shenzi	64.0	91.9	33.5	51.2
	Shenzi North	16.4	26.8	11.6	18.9
	Atlantis	59.4	153.9	55.6	117.0
	Mad Dog	129.2	180.0	40.1	55.9
T&T	Angostura	1.6	1.9	167.9	230.1
	Ruby	1.4	1.8	24.0	33.2
	Total	**311.9**	**518.0**	**3,724.4**	**5,616.1**

Notes:

1. Net Reserves are BHP Petroleum's net economic entitlement volume after the deduction of royalties, or according to the terms of the PSC governing the asset.
2. Net gas reserves include NGL volumes and 462 Bcf (1P)/677 Bcf (2P) consumed in operations (CiO or fuel); the Competent Person's Report presents CiO volumes, company net NGL reserves and company net gas reserves excluding fuel in separate tables.
3. Gas reserves include NGL volumes. Conversion assumes one bbl of NGL equals 6,000 scf of natural gas.
4. Totals may not exactly equal the sum of the individual entries because of rounding.

BHP Petroleum's Net Contingent Resources as at 31 December 2021

Country	Asset	Net 2C Contingent Resources	
		Oil and Condensate (MMbbl)	Gas (Bcf)
Australia	Bass Strait	18.1	138
	NWS	15.1	289
	Pyrenees	16.4	0
	Macedon	0.0	107
	Greater Scarborough	0.0	659
	Greater Enfield	0.0	38
U.S. GOM	Shenzi	25.0	7
	Wildling	36.9	11
	Atlantis	88.3	38
	Mad Dog	70.2	4
Mexico	Trion	282.6	210
T&T	Angostura	1.3	219
	Calypso	4.9	2,877
	Magellan	0.0	313
	Total	**558.8**	**4,910**

Notes:

1. Net Contingent Resources in this table are BHP Petroleum's working interest fraction of the gross field Contingent Resources; they do not represent BHP Petroleum's actual net entitlement under the terms of the contracts that govern the assets, which would be lower for PSCs or where royalty is deductible.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the asset may not be developed in the form envisaged or may not be developed at all (i.e. no "Chance of Development" (Pd) factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Contingent gas resources include NGL volumes. Conversion assumes one bbl of NGL equals 6,000 scf of natural gas.
5. Totals may not exactly equal the sum of the individual entries because of rounding.
6. No deduction has been made for fuel, flare and shrinkage.

6 Group structure

Set out below is BHP Petroleum's list of subsidiaries. The list of subsidiaries contains all group members with the exception of certain entities in which BHP Petroleum holds an insignificant minority shareholding.

	Entity	Location	Ownership
	BHP Petroleum International Pty Ltd	Australia	100.00%
	BHP Petroleum Pty Ltd	Australia	100.00%
	North West Shelf Liaison Company Pty Ltd	Australia	16.67%^
	North West Shelf Shipping Service Company Pty Ltd	Australia	16.67%^
	Perdido Mexico Pipeline Holdings, S.A. de C.V.	Mexico	99.99%[1]
	Perdido Mexico Pipeline, S. de R.L. de C.V.	Mexico	99.99%[1]
	BHP Petroleum Investments (Great Britain) Pty Ltd	Australia	100.00%
	BHP Billiton Brasil Investimentos de Petróleo Ltda.	Brazil	99.97%[2]
	BHP Billiton Brasil Exploração e Produção de Petróleo Limitada	Brazil	99.99%[3]
	BHP Billiton Petroleum Limited	United Kingdom	100.00%
	BHP Petroleum (North West Shelf) Pty Ltd	Australia	100.00%
	North West Shelf Lifting Coordinator Pty Ltd	Australia	16.67%^
	North West Shelf Gas Pty Limited	Australia	16.67%^
	International Gas Transportation Company Limited	Bermuda	16.67%^

	Entity	Location	Ownership
	China Administration Company Pty Ltd	Australia	16.67%^
	BHP Petroleum (Tankers) Limited	Bermuda	100.00%[4]
	BHP (Trinidad) Holdings Ltd.	Saint Lucia	100.00%
	BHP (Trinidad-3A) Ltd	Trinidad & Tobago	100.00%
	BHP Billiton Petroleum Holdings (USA) Inc.	United States	90.00%[5]
	Hamilton Brothers Petroleum Corporation	United States	100.00%
	Hamilton Oil Company Inc.	United States	100.00%
	BHP Billiton Boliviana de Petroleo Inc.	United States	100.00%
	BHP Petroleum (North America) LLC	United States	100.00%
	BHP Billiton Petroleum (Americas) Inc.	United States	100.00%
	BHP Billiton Petroleum (GOM) Inc.	United States	100.00%
	Oil Insurance Limited	Bermuda	2.20%^
	BHP Hawaii Inc.	United States	100.00%
	Iwilei District Participating Parties, LLC	United States	14.96%^
	BHP Resources Inc.	United States	100.00%
	BHP Holdings (Resources) Inc.	United States	100.00%
	Broken Hill Proprietary (USA) Inc.	United States	100.00%
	BHP Billiton Marketing Inc.	United States	100.00%
	BHP Billiton Petroleum (Deepwater) Inc.	United States	100.00%
	Caesar Oil Pipeline Company, LLC	United States	25.00%^
	Cleopatra Gas Gathering Company LLC	United States	22.00%^
	Marine Well Containment Company LLC	United States	10.00%^
	BHP Petroleum (Foreign Exploration Holdings) LLC	United Kingdom	100.00%
	BHP Petroleum (Trinidad Block 3) Limited	United Kingdom	100.00%
	BHP Petroleum (Trinidad Block 6) Limited	United Kingdom	100.00%
	BHP Petroleum (Trinidad Block 5) Limited	United Kingdom	100.00%
	BHP Billiton Petroleum (Trinidad Block 7) Limited	United Kingdom	100.00%
	BHP Petroleum (Trinidad Block 14) Limited	United Kingdom	100.00%
	BHP Petroleum (Trinidad Block 23A) Limited	United Kingdom	100.00%
	BHP Billiton Petroleum (Trinidad Block 23B) Limited	United Kingdom	100.00%
	BHP Petroleum (Trinidad Block 28) Limited	United Kingdom	100.00%
	BHP Petroleum (Trinidad Block 29) Limited	United Kingdom	100.00%
	BHP Petroleum (Bimshire) Limited	United Kingdom	100.00%
	BHP Billiton petroleum (South Africa 3B/4B) Limited	United Kingdom	100.00%
	BHP Petroleum (Egypt) Limited	United Kingdom	100.00%
	BHP Petroleum (Carlisle Bay) Limited	United Kingdom	100.00%
	BHP Petroleum (Mexico) Limited	United Kingdom	100.00%
	BHP Billiton Petróleo Servicios Administrativos, S. de R.L. de C.V.	Mexico	99.00%[6]
	BHP Billiton Petróleo Servicios de México, S. de R.L. de C.V.	Mexico	99.00%[6]
	BHP Petroleum (Mexico Holdings) LLC	United States	100.00%
	Operaciones Conjuntas, S. de R.L. de C.V.	Mexico	99.00%[6]
	BHP Billiton Petróleo Holdings de México, S. de R.L. de C.V. *	Mexico	99.99%[6]
	BHP Billiton Petróleo Operaciones de México, S. de R.L. de C.V. *	Mexico	99.00%[6]
	BHP Petroleum (Australia) Pty Ltd	Australia	100.00%

	Entity	Location	Ownership
	BHP Petroleum (International Exploration) Pty Ltd	Australia	100.00%
	BHP Petroleum (Bass Strait) Pty Ltd	Australia	100.00%
	BHP Petroleum (Victoria) Pty Ltd	Australia	100.00%
	BHP Billiton Petroleum Holdings LLC	United States	100.00%
	BHP Billiton (Trinidad-2C) Ltd	Canada	100.00%
	BHP Petroleum (New Ventures) Corporation	Canada	100.00%

Notes: (^) Remainder of shares externally owned.

(1) 0.01% owned by BHP Petroleum Investments (Great Britain) Pty Ltd
(2) 0.03% owned by BHP Petroleum International Pty Ltd
(3) 0.01% owned by BHP Petroleum International Pty Ltd
(4) BHP Petroleum (Tankers) Limited is in the process of being liquidated. A final shareholder meeting in connection with the liquidation is scheduled for 12 April 2022
(5) 90% Voting; 37.67% Capital; BHP Billiton Petroleum Holdings LLC (10% Voting; 62.33% Capital)
(6) BHP Petroleum (Mexico Holdings) LLC (0.01 - 1%)

Note: where the shade of colour changes, the entity listed directly above the subsidiary is the parent. See * for an example

Subsidiary Level I

Subsidiary Level II

Subsidiary Level III

Subsidiary Level IV

Subsidiary Level V

7 Financial Information

BHP Petroleum is a subset of entities wholly owned by BHP Group Limited and whose parent is BHP Petroleum International Pty Ltd. The registered office of BHP Petroleum International Pty Ltd is 125 St Georges Terrace, Perth Western Australia 6000, Australia.

This subset of entities primarily represents BHP Group Limited’s interests in its petroleum businesses, whose principal activities are the exploration, development and production of oil and gas. These petroleum businesses comprise of conventional oil and gas assets located in the U.S. GOM, Australia, T&T, Algeria and Mexico, and appraisal and exploration options in T&T, central and western U.S. GOM, Eastern Canada, Barbados and Egypt.

A list of the subsidiaries of BHP Petroleum International Pty Ltd is set out above at paragraph 6 of this Part 8 and includes the legal entities carved out from BHP Group Limited in connection with the Merger. BHP Petroleum consists of BHP Petroleum International Pty Ltd and the entities it controls, except for the Restructure Entities.

While BHP Petroleum’s reserves and resources as of 30 June 2021 and the combined financial statements of BHP Petroleum are inclusive of BHP Petroleum’s 28.85% interest in the Algerian Assets, these assets are currently classified as non-core and are expected to be divested prior to the Implementation of the Merger. For further information regarding the Algerian Assets, see paragraph 11 of this Part 8.

Basis of presentation of BHP Petroleum Historical Financial Information

The BHP Petroleum Historical Financial Information included in Annexure 2 of this Prospectus represents non-statutory combined financial statements that are intended to provide general purpose historical financial information of BHP Petroleum. They are combined financial statements, rather than consolidated financial statements on the basis that not all entities controlled by BHP Petroleum International Pty Ltd have been included in the carve out financial statements (on the basis that not all are included within the scope of the Merger). The Restructure Entities have been excluded from the scope of the Merger and excluded from the carve out financial statements. The combination of entities within BHP Petroleum has been prepared in accordance with the consolidation procedures set out in IFRS 10 Consolidated Financial Statements.

The financial information has been extracted from the accounting records of BHP Group Limited for the purposes of presenting the combined financial position, combined results of operations and combined cash flows of BHP Petroleum. The combined financial statements therefore reflect assets, liabilities, revenues and expenses directly attributable to BHP Petroleum identified above. A list of the subsidiaries included within BHP Petroleum's combined financial statements is included in Note 23, BHP Petroleum Assets financials statements set out in Part 18 *(Operating and Financial Review of BHP Petroleum)* of this Prospectus.

BHP Petroleum has adopted the same accounting policies as BHP Group, unless otherwise stated.

The combined financial statements of BHP Petroleum as at and for the reporting periods:

- are combined general purpose financial statements;
- have been prepared in accordance with the requirements of the Corporations Act and the UK Companies Act 2006;
- were prepared in accordance with IFRS;
- are prepared on a going concern basis;
- measure items on the basis of historical cost principles, except for the following items:
  - derivative financial instruments and certain other financial assets and liabilities, which are carried at fair value;
- include significant accounting policies in the notes to the financial statements that summarise the recognition and measurement basis used and are relevant to an understanding of the combined financial statements;
- apply a presentation currency of US dollars, consistent with the predominant functional currency of BHP Petroleum's operations. However, some subsidiaries and joint arrangements have functional currencies other than US dollars;
- round amounts presented to the nearest million dollars, unless otherwise stated;
- adopt all new and amended standards and interpretations under IFRS issued by the relevant bodies (refer to Note 25 'New and amended accounting standards and interpretations'), that are mandatory for application in periods beginning on 1 July 2019. Those new and amended standards and interpretations did not require restatement of prior period financial information;
- early adopted amendments to IFRS 9 'Financial Instruments' (IFRS 9); IAS 39 'Financial Instruments: Recognition and Measurement' (IAS 39); IFRS 7 'Financial Instruments: Disclosures' (IFRS 7) and IFRS 16 'Leases' (IFRS 16) in relation to Interest Rate Benchmark Reform (refer to Note 25 'New and amended accounting standards and interpretations'); and
- have not early adopted any other standards and interpretations that have been issued or amended but are not yet effective.

The accounting policies are consistently applied by all entities included in BHP Petroleum.

Part 9 – Industry Overview

1 Overview

Woodside Overview

Woodside operates as an explorer for and producer of energy products.

Woodside's Australian operations are primarily in Western Australia. Domestic gas is sold to customers in Western Australia. LNG, LPG, condensate and oil are sold to customers primarily in Asia. Woodside's operations outside of Australia are not in production.

BHP Petroleum Overview

BHP Petroleum's Australian operations are in the East and West coast of Australia. Domestic gas is sold to Australian customers. Crude oil and gas are sold to customers in Japan, South Korea and China. BHP Petroleum's global operations are in the U.S. GOM and T&T. Crude oil products from BHP Petroleum's U.S. GOM operations are sold into the U.S. domestic and global oil market with gas volumes sold into the U.S. domestic gas market. Similarly, crude oil produced from BHP Petroleum's T&T operation is sold into the global oil market and gas volumes are sold domestically.

2 Australia Oil and Gas Overview

Australia is home to substantial onshore and offshore oil and gas reserves, the development of which has underpinned the nation's position as a leading global LNG exporter.

There are two distinct regional gas markets which service domestic gas consumption, one on each coast of Australia.

3 West Coast of Australia Domestic Gas Market

The WA domestic gas market primarily services several large industrial consumers and mining firms, the majority of which are supplied directly through the transmission network (such as the Dampier to Bunbury Natural Gas Pipeline and the Goldfields Gas Pipeline). The remaining large customers are supplied by domestic LNG facilities, which convert natural gas to LNG which is then transported by road. Customers supplied through the retail distribution network account for 6% of WA's total domestic gas consumption. Despite its relatively small population, WA has the highest natural gas consumption of all Australian states. WA consumed 669 PJ of gas in 2018-2019, approximately 42% of Australia's total gas consumption.

The large majority of gas reserves in WA are from conventional reservoirs located in the Carnarvon and Perth basins. While most of WA's gas reserves are developed as LNG export projects, domestic supply in WA is underpinned by a domestic gas reservation policy ("**WA Domestic Gas Policy**"). Under the policy, introduced in 2006, gas equivalent to 15% of LNG production from LNG export projects is required to be reserved for domestic use as a condition of LNG project approval. The policy contains flexibility, allowing negotiations to occur on a case-by-case basis regarding the method by which the LNG project proponents fulfil their domestic gas commitments, including from alternative sources.

Key recent trends

In 2021, a number of producers made progress on developing and commercialising domestic gas fields and LNG projects which is likely to contribute to supply in the coming years. Demand for WA's key commodities, particularly gold and iron ore, has remained strong throughout the COVID-19 pandemic which has flowed through to increased domestic gas demand for mining operations.

The WA Government clarified the WA Domestic Gas Policy to state that it would not agree to exports of gas through the WA pipeline network, and that supply of gas to the east coast would be treated as an export for the purposes of the policy.

In the past 18 months there has been an increase in proposed hydrogen projects, with a number of producers, including Woodside entering into hydrogen development opportunities. As at January 2022, the WA Government was funding seven renewable hydrogen feasibility studies as part of the Renewable Hydrogen Strategy. The studies include examining solar hydrogen for waste collection and light vehicle fleets in Cockburn, a hydrogen refuelling hub in Mandurah, and the potential for an electrolysis hydrogen production plant in the Great Southern or Wheatbelt regions of Western Australia.

Market dynamics

The WA domestic gas market is characterised by:

- Large gas reserves that are generally located offshore and developed mainly to supply the global LNG market.
- A limited number of large suppliers/producers and consumers.
- Bilateral, confidential, long-term take-or-pay gas sales contracts.
- Residential, commercial, and small industrial consumers comprising a small proportion of total demand.
- Small volumes of short-term and spot gas sales.
- A small number of pipelines, interconnectors, and limited surplus pipeline capacity.
- Information about supply that is available to be contracted, potential buyers, and gas contract pricing is not readily available.
- 78 PJ of storage capacity.

Demand outlook

Gas consumption in WA is expected to be supported by strong demand for the State's commodities through the development of new resources projects. Long-term west coast gas demand is expected to grow moderately at an average annual rate of 0.8% until 2031, growing from 1,071 TJ/day in 2022 to 1,150 TJ/day in 2031. In 2021, large customers accounted for ~85% of gas consumed in WA with a majority of gas consumed in the minerals processing, mining and electricity generation sectors.

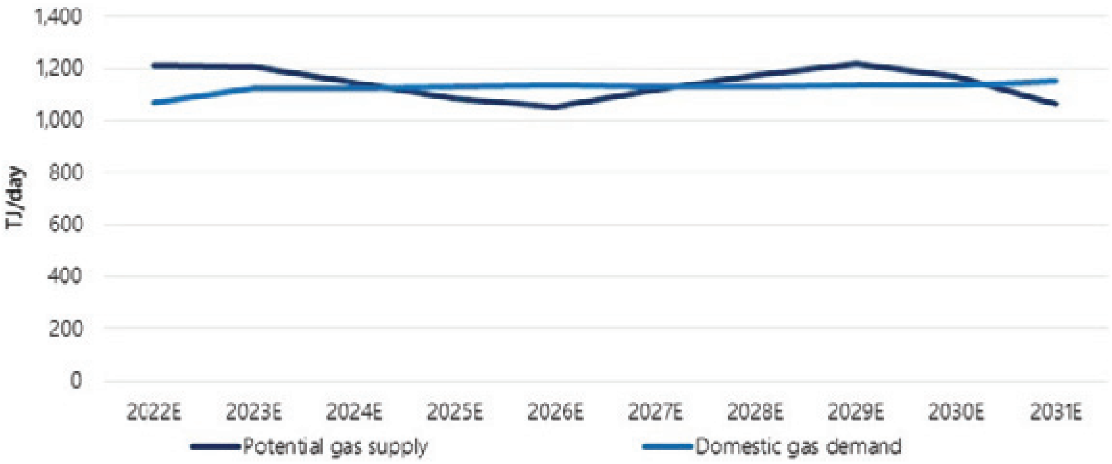
Supply outlook

Gas supply to the WA domestic market is largely dependent on the sustained development of gas reserves. Overall, potential gas supply is projected to decline at an average annual rate of 1.40% between 2022 and 2031. There is a large volume of undeveloped gas from fields such as Clio-Acme and Equus that could supply the WA domestic market over the next 10 years but are currently too speculative to include in its potential supply forecasts.

Supply and demand balance

The supply of gas in the Western Australian domestic gas market is expected to be sufficient to meet demand until 2024. Between 2025 and 2027 gas demand may exceed supply by 51 PJ in total across these years, at rates of up to 85 TJ/day in 2026 (up to 7% of daily demand). From 2027, the Scarborough project is forecast to supply up to 210 TJ/d into the domestic market. The development of Perdaman Chemical and Fertiliser's proposed urea project would add a large new consumer to the Karratha region; it is expected to start production in 2025 (subject to FID). Post-2030, declining reserves at domestic gas only facilities is expected to cause forecast gas demand to again exceed forecasted supply.

Figure– 17 – Domestic gas market balance, base scenario, 2022 to 2031



4 East Coast of Australia Domestic Gas Market

Market overview

Australia's east coast gas market includes New South Wales, Australian Capital Territory, Queensland, South Australia, Victoria and Tasmania, is connected by gas transmission pipelines, and also sources gas supply from the Northern Territory via the Northern Gas Pipeline. This market is characterised by:

- Short-term gas hubs which provide greater price discovery and trading flexibility.
- Domestic gas demand of 553 PJ (2021), from the industrial, residential and commercial, and gas-fired power generation sectors.
- Key supply basins which include the Surat–Bowen Basin (Queensland), the Cooper Basin (South Australia), and Otway, Gippsland, and Bass Basins (Victoria).
- Three LNG export projects located in Queensland, which consume about 70% of gas production in Eastern Australia.
- Approximately 200 PJ of gas storage capacity.

Key recent trends

Gas sales in the east coast gas market are heavily contract-based, with only a small share of production traded on the wholesale (spot) market. This is because long-term contracts provide producers the confidence to invest in new gas supply, and gas consumers security of supply at agreed price indices and levels. Bilateral contracts are negotiated between buyers and sellers, with a shift towards more shorter-term contracts in recent years. Negotiated price outcomes are generally not disclosed to the market.

Several spot hubs exist for short-term trading, however these volumes account for a relatively small share of the market (approximately 10-20%) and are used for market balancing by gas players.

Higher marginal costs of supply for new supply sources available in the east coast market may put upward pressure on prices, compared to pre-2015 levels. There is a forecasted risk of gas shortfalls in the east coast gas market as soon as winter 2023, prompting several developers to propose LNG import terminals to be built on the east coast.

Demand outlook

The outlook for gas demand in the long-term is uncertain, with forecasted scenarios ranging from relatively flat demand to steadily declining demand over time. This uncertainty arises from potential policy changes (e.g. Victoria's proposed Gas Substitution Roadmap), the availability of gas supply that is affordable for more price-sensitive consumers, and the outlook for gas-fired power generation, which is subject to the growth of renewable energy and electricity storage, coal power plants, and electricity transmission connectivity between regions. Gas-fired power generation is increasingly playing a critical balancing role in the power sector, for periods of lower renewable energy and/or coal-fired power generation, making gas-fired power demand subject to short-term events.

Supply outlook

The east coast market's supply outlook is forecast to be challenged, as reserves located near domestic demand centres in offshore Victorian basins, particularly the Gippsland Basin, are in decline.

The proposed introduction of LNG import terminals on the east coast of Australia at various locations (e.g. Victoria, New South Wales, and South Australia), could address these supply shortfall risks and provide incremental supply.

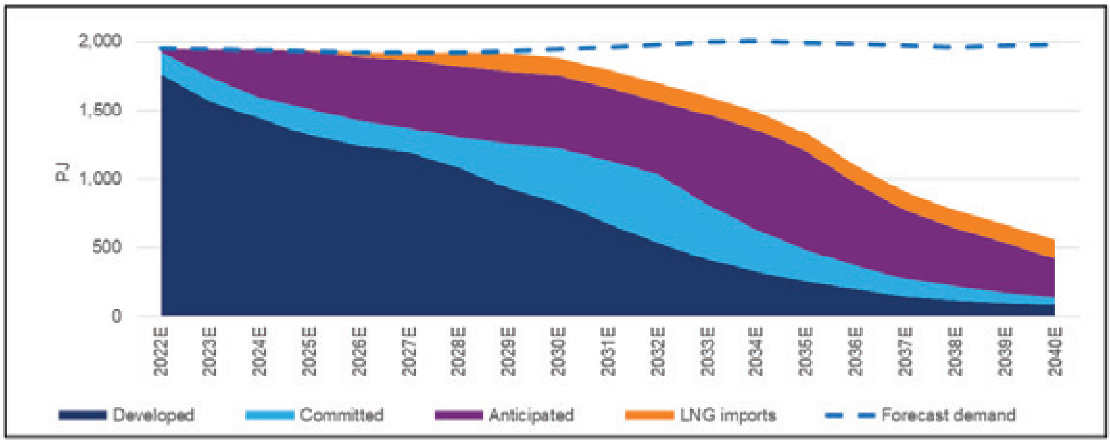
In April 2021 BHP announced the successful commissioning of the Gippsland Basin Joint Venture's West Barracouta natural gas field in the Bass Strait offshore Victoria, which will provide new domestic gas supply to Australia's east coast. The West Barracouta field is the largest domestic gas project in Australia in recent years and will help to increase the supply of gas to the East Coast of Australia. In March 2022, ExxonMobil announced it was making incremental investments to deliver an additional 200 PJ of gas over the next five years, through the Gippsland Basin Kipper offshore field and the Turrum field.

Santos' proposed Narrabri gas project in New South Wales has targeted FID for 2023 and would add a large new supply source if progressed.

Supply and demand balance

The east coast gas market is likely to have future supply shortfalls without the development of further gas resources and LNG import terminals. While the northern region of the East Coast of Australia will be self-sufficient in gas until 2030, the southern region, (which includes NSW/ACT, Victoria, Tasmania and South Australia) is contending with the decline of legacy basins. Gas supply to meet this shortfall may come from Queensland, Northern Territory, and/or LNG import terminals. However, pipeline capacity limitations and costs may constrain the available gas supply to the most southern states in particular: Victoria and Tasmania.

Figure– 18 – Projected eastern and south-eastern Australia gas production (including export LNG), Central scenario, existing, committed, and anticipated developments, 2022E-2040E (PJ)



5 LNG Market

Market overview

The LNG market is a global export-driven market dominated by larger players, with Australia being the largest LNG exporter by volume, producing 79.2 Mt compared to Qatar at 78.0 Mt and the U.S. at 67.5 Mt.

Key recent trends

The global LNG price recovery has accelerated since the lows experienced on the back of the COVID-19 pandemic, supported by a recovery in Chinese LNG demand which was up 20% in the second half of 2021 vs 2020, European carbon prices and other factors.

Global production in 2021 grew by 20 Mt on 2020 volumes. However, much of the "growth" is a result of LNG plants in marginal supply markets such as Egypt and the U.S. which are returning to regular production profiles after operating at reduced levels in 2020 due to depressed LNG prices. Supply has not been quick to rebound following the COVID-19 pandemic as a result of lower investment over 2015-2017 and also because of delays to several projects under-construction. Organic supply growth is expected to return in 2022, as new projects in the U.S. and Indonesia come online. Overall capacity additions from under-construction projects during 2023-2025 are expected to be small, with Tortue FLNG Phase 1 (on the border of Senegal and Mauritania) expected in 2023 and Costa Azul Phase 1 (Mexico) in 2025. Woodside's Scarborough development is targeted to come online in 2026. The current conflict between Russia and Ukraine is likely to affect Russian projects, such as Arctic LNG-2 which had been expected to become operational in late 2023, and delays are possible.

Market dynamics

The majority of Australian LNG is sold into the Asia Pacific market under long-term bilateral contract arrangements, with pricing indexed to the price of crude oil. Historically these contracts have had durations of up to 25 years. This provided producers, particularly for greenfield projects, with a level of certainty on the recovery of significant upfront investment and provided purchasers long-term security of energy supply. In recent years, primarily due to the increased liquidity in the global LNG market, producers and purchasers in the Asian region have concluded bilateral contracts over shorter durations of between 5 and 15 years.

Historically the exact terms of the oil price linkage in Asian LNG contracts is negotiated confidentially between buyers and sellers, with contracted LNG prices traditionally linked to the price of JCC crude oil. JCC reflects the average price of crude oil imported into Japan and closely correlates to the lagged price of Brent oil. In recent years, Brent oil has been commonly used as a contract price marker for LNG in the Asian region, particularly in China, Korea, Taiwan, India and south-east Asia. This contrasts with the spot market pricing of domestic natural gas in North America, and to a lesser extent Europe, where competing sources of gas (pipeline and LNG) are priced in hubs. LNG exports from the United States are commonly indexed to the US natural gas hub, Henry Hub.

In addition, as global markets become increasingly interdependent and physical liquidity rises, there has been an increase in term and spot sales arrangements in the Asia-Pacific region priced off the Platts JKM benchmark price assessment, which is reflective of gas-on-LNG competition and prevailing LNG market supply-demand balances.

Long-term LNG contracts are often subject to periodic price review which may occur through bilateral agreement or be triggered contractually as a result of significant movements in oil price. This is particularly the case with contracts greater than ten years in duration. While most of Australia's LNG production continues to be traded via long-term contracts, there has been an increase in spot sales and short-term contract sales. A key contributing factor is the greater flexibility that short-term contracts can provide in terms of responding to changes in sources of supply and demand for LNG.

Demand outlook[33]

According to Wood Mackenzie, global LNG demand is expected to more than double in volume between 2021 and 2050. With indigenous production decline in Europe and parts of Asia, LNG imports are expected to become the preferred supply type for many economies. Europe for example, could see LNG demand increase by 51 Bcm despite overall gas demand declines of 184 Bcm in 2021-2050. Asia represents almost 90% of all the gas demand growth for 2021-2050, and Australian LNG producers benefit from the close proximity to and long-term relationships with customers in Asian markets.

While there are challenges posed for natural gas demand due to the energy transition, Wood Mackenzie[34] is forecasting global gas demand to grow between 2021 and 2035. Natural gas's share in global total primary energy demand is expected to peak by the early 2040s, highlighting the role gas is expected to play in supporting the energy transition in the medium to longer-term. However, gas demand could see a substantial decline under Wood Mackenzie's AET - 1.5 scenario (Accelerated Energy Transition 1.5-degree scenario). Wood Mackenzie's AET – 1.5 scenario outlines a view of the world that limits the average rise in global temperatures to 1.5°C compared with pre-industrial times.

33 This paragraph includes statistical data and market analysis regarding global gas demand. This information has been taken from information published by Wood Mackenzie, a provider of market overview and analysis, in a report entitled "Commodity Report, Global Gas Demand" dated October 2021. This is licenced from Wood Mackenzie by Woodside.

34 This paragraph of the Prospectus includes statistical data and market analysis regarding global gas demand. This information has been taken from information published by Wood Mackenzie, a provider of market overview and analysis, in a report entitled "Commodity Report, Global Gas Demand" dated October 2021. This is licenced from Wood Mackenzie by Woodside

Supply outlook

The 2020 COVID-19 pandemic and low oil and gas prices in 2020 resulted in a number of delays to the start dates for new LNG supply projects that are under-construction and to the timelines for projects that were proposed to take final investment decisions. In 2020, only one project took final investment decision, the Energia Costa Azul LNG project in Mexico. In 2021, a few projects have taken final investment decisions, including Qatar's North Field East project, the Darwin LNG backfill (Barossa) in Australia, Russia's Baltic LNG (Ust-Luga) and the Scarborough-Pluto Train 2 project in Australia.

More than 96 Mtpa of under-construction LNG capacity is likely to become operational between 2026 and 2030. In addition, Wood Mackenzie estimates that up to 80 Mtpa of supply capacity will take FID within the next 36 months.

In the longer-term, Qatar, Russia and the U.S. were forecast to dominate LNG supply additions into the next decade, based on the large number of current project proposals and substantial and relatively low-cost gas resources. Russia's role in energy markets post the invasion of Ukraine is uncertain.

6 Oil Market

Market overview and dynamics

The COVID-19 pandemic reduced oil demand in 2020 to well below 2019 levels. After an increase of 5.6 MMbbl/d in 2021, the IEA estimates that oil demand will grow by 2.1 MMbbl/d in 2022 to reach 99.7 MMbbl/d, slightly above pre-COVID-19 levels. The forecast reflects new estimates of reduced demand as a result of the Russian-Ukraine conflict.

In the second quarter of 2020, the oil market saw oil supply heavily outpacing world oil demand, leading to an increase in global oil inventories within a short span of a couple of months. In response to this situation, in April 2020, OPEC and non-OPEC oil producing countries participating in the 'Declaration of Cooperation', known as OPEC+, announced voluntary productions adjustments commensurate with the material oil stock surplus, to achieve the rebalancing and stabilisation of the oil market.

Since early 2020, OPEC+ has been playing a significant role in balancing the market through production curbs. OPEC+ member countries have the ability to produce over 40% of the world's crude oil. Equally important to global prices, OPEC+ oil exports can represent more than 60% of the total petroleum traded internationally. Due to this market share, OPEC+ actions can, and do, influence international oil prices.

The extent to which OPEC+ utilises available production capacity is often used as an indicator of the tightness of global oil markets, as well as an indicator of the extent to which OPEC+ is exerting upward influence on prices. The U.S. Energy Information Administration defines spare capacity as the volume of production that can be brought on within 30 days and sustained for at least 90 days. Saudi Arabia, the largest oil producer within OPEC+ and the world's largest oil exporter, historically has had the greatest spare capacity. Saudi Arabia generally keeps more than 1.5 – 2 MMbbl/d of spare capacity on hand for market management. OPEC+ spare capacity provides an indicator of the world oil market's ability to respond to potential crises that reduce oil supplies. As a result, oil prices tend to incorporate a rising risk premium when OPEC spare capacity reaches low levels.

Australia holds just 0.3% of the world's oil reserves as of September 2021. Most of Australia's known remaining oil resources are LPG and condensate, associated with offshore gas fields in the Browse, Carnarvon, and Bonaparte basins. Australian oil production has been in decline since 2009 as new reserve developments have failed to match the rate of depletion in existing fields. Oil production in 2019 showed a reversal to this long-term trend following the start-up of the Greater Enfield (Woodside operated), Ichthys and Prelude projects.

The U.S. GOM area, both onshore and offshore, is one of the most important regions for energy resources and infrastructure. In 2021, production from the U.S. GOM was affected by hurricane activity which resulted in prolonged outages.

Key recent trends

As at March 2022, oil prices were at decade highs reflective of markets pricing in a geopolitical risk premium as a result of the conflict between Russia and Ukraine (Dated Brent was US$127/bbl and WTI was US$115/bbl) as a shortage of natural gas, LNG and coal boosted demand for oil as economic growth continues and global mobility improves. Despite increasing global COVID-19 cases in Q4 2021, measures taken by the governments to contain the virus were less severe than during earlier waves and the resulting impact on economic activity and oil demand was relatively subdued. Oil demand exceeded IEA expectations in Q4 2021 increasing by 1.1 MMbbl/d to 99 MMbbl/d. Prior to Russia's invasion of Ukraine, world oil supply was projected to rise sharply in 2022 towards the year end as U.S. output bounces back from Hurricane Ida and responds to the higher price environment and OPEC+ continues to unwind cuts. Canada and Brazil are also expected to achieve record production levels. Additionally in January 2022 Ecuador, Libya and Nigeria were already ramping up production.

The current conflict between Russia and Ukraine is also expected to create a supply shock, with the IEA estimating that from April 2022 as much as 3MMbbl/d of Russian oil production could be shut in as a result of sanctions and self sanctions.

Long term demand and supply outlook

Demand for crude oil and petroleum products is influenced by many factors and is impossible to predict with certainty. Specifically, factors such as the rate of global economic growth, evolving energy policies, and technological trends will have material impacts on the path for long-term oil demand. The policies undertaken by governments to reduce carbon emissions will play a significant role in determining this path.

Wood Mackenzie estimated[35] in November 2021 that global total liquids demand would continue to grow until peaking in 2034 at 108 MMbbl/d and then gradually decline thereafter. Under this outlook, by 2050 total demand will have retreated to 96 MMbbl/d, approximately 4 MMbbl/d lower than 2019 levels.

Other forecasters may make different assumptions about the drivers of oil demand and thus may have alternate outlooks. In addition, many forecasters consider the potential impact of global policies that could limit the average rise in global temperatures to 2°C or 1.5°C compared with pre-industrial times. Wood Mackenzie has developed such scenarios. For example, in their AET-1.5 scenario, which assumes that the average rise in global temperatures is limited to 1.5°C compared with pre-industrial times, oil demand peaks earlier and declines more rapidly than in the outlook described above. Under this scenario, oil demand declines by nearly two thirds from current levels by 2050.

Potential sources of supply to meet future oil demand include currently producing fields in the OPEC+ countries, the US and elsewhere, and new oil developments. With Russia being one of the world's largest oil producers, the ongoing conflict between Russia and Ukraine and associated sanctions has created uncertainty over the long-term supply outlook from that region.

[35] This paragraph of the Prospectus includes statistical data and market analysis regarding oil supply and demand. This information has been taken from information published by Wood Mackenzie, a provider of market overview and analysis, in a report entitled "Macro Oils, Long-term 2021 Outlook to 2050" dated November 2021. This is licenced from Wood Mackenzie by Woodside.

Part 10– Summary of the Merger

This section sets out a summary of some of the key information in respect of the Merger. Admission is conditional on Implementation. The Merger is subject to satisfaction or waiver (if permitted) of various Conditions including Woodside Shareholder Approval and regulatory and other approvals. If the Merger does not proceed, then Admission will not take place.

1 Background

On 17 August 2021, Woodside and BHP announced that they had entered into a Merger Commitment Deed, with an effective date of 1 July 2021, to combine their respective oil and gas portfolios through an all-stock merger. The Merger will be on a cash-free and debt-free basis, where BHP Petroleum will settle all intercompany loan balances prior to Implementation.

With the combination of two high quality asset portfolios, the Merger is expected to create a top 10 global independent energy company by production and the largest energy company listed on the ASX[36]. Woodside believes that the Merger will help it supply the energy needed for global growth, and support its financial resilience, through the energy transition.

On 22 November 2021, Woodside and BHP entered into a binding Share Sale Agreement to implement the Merger (together with an Integration and Transition Services Agreement which sets out the parties' obligations in relation to the separation, transition and integration of BHP's oil and gas portfolio with Woodside's oil and gas portfolio).

2 Overview of the Merger

If the Merger is implemented, Woodside will acquire all of the issued share capital in BHP Petroleum International Pty Ltd, which holds BHP's oil and gas business, and Woodside will issue 914,768,948 New Woodside Shares to BHP as part of the Merger Consideration,[37] with those New Woodside Shares to be immediately distributed by BHP to Eligible BHP Shareholders (and transferred to the Sale Agent, in the case of New Woodside Shares attributable to Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders).

The Merged Group will be owned approximately 52% by Existing Woodside Shareholders and 48% by BHP Shareholders (subject to adjustment in certain circumstances and subject to any BHP Shareholders being Ineligible Foreign BHP Shareholders or Relevant Small Parcel BHP Shareholders). The Merger is subject to satisfaction (or waiver, if permitted) of various Conditions including Woodside Shareholder Approval and regulatory and other approvals as detailed in paragraph 9 of this Part 10 *(Summary of the Merger)* of this Prospectus.

If all of the Conditions are satisfied (or waived, if permitted), including Woodside Shareholder Approval, then:

- 100% of the issued share capital of BHP Petroleum International Pty Ltd will be transferred to Woodside (or its nominee) and BHP Petroleum will become a wholly owned subsidiary of Woodside;
- Woodside will pay to BHP the Merger Consideration, including the Share Consideration of 914,768,948 New Woodside Shares which will be issued to BHP;[38]
- BHP will immediately distribute to Eligible BHP Shareholders (and transfer to the Sale Agent, in the case of New Woodside Shares attributable to Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders) the Share Consideration, pro rata to their respective ownership of BHP; and
- Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders will receive a cash payment from the proceeds of the sale of New Woodside Shares by the Sale Agent in lieu of receiving New Woodside Shares. Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders will not receive New Woodside Shares in connection with the Merger.

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[36] Top 10 global independent energy company by hydrocarbon production. Woodside analysis based on the Wood Mackenzie Corporate Benchmarking Tool Q4 2021, 1 December 2021. See the section titled 'Disclaimer and Important Notices' for clarification of independent energy company.

[37] The number of New Woodside Shares to be issued assumes that no additional Woodside Shares are issued in connection with a Permitted Equity Raise and no further declaration of Woodside Dividends will occur prior to Implementation.

[38] The number of New Woodside Shares to be issued assumes that no additional Woodside Shares are issued in connection with a Permitted Equity Raise and no further declaration of Woodside Dividends will occur prior to Implementation.

Following Implementation, the Merged Group will comprise Woodside and its Subsidiaries, including each BHP Petroleum Group Member.

From the date of issue, the New Woodside Shares issued as the Share Consideration will be fully paid and rank equally with Woodside Shares currently on issue. Following Implementation, Woodside Shares will continue to be listed on ASX, and Woodside has made applications for secondary listings on securities exchanges in the United States (in the form of Woodside ADSs) and the United Kingdom.

BHP Shareholders will not be required to surrender their BHP Shares pursuant to the Merger. The Implementation will not result in any change to any BHP Shareholder's ownership of BHP Shares.

3 Parties to the Merger

Woodside

Incorporated in Victoria, Australia on 17 August 1971, Woodside is listed on the ASX with the ticker symbol "WPL". Woodside's principal office is Mia Yellagonga 11 Mount Street Perth WA 6000, Australia.

Woodside led the development of the LNG industry in Australia and is recognised for its world-class capabilities as an integrated upstream supplier of energy.

Woodside's producing portfolio is primarily centred around the production of LNG from conventional offshore projects in Western Australia and also includes oil, condensate, LPG and domestic gas for Western Australian customers. In addition to its producing assets, Woodside is currently progressing the development of the Scarborough gas resource through an expansion of the Pluto LNG facility in Western Australia. Internationally, Woodside is executing the Sangomar Field Development Phase 1 in Senegal.

As an Australian leading LNG operator, Woodside operated 5% of global LNG supply in 2021. Woodside's proven track record and distinctive capabilities are underpinned by more than 65 years of experience.

Further details on Woodside can be found in Part 7 (*Overview of Woodside*) of this Prospectus.

BHP and BHP Petroleum

Incorporated in Australia in 1885, BHP is listed on the ASX with the ticker symbol "BHP". BHP is the world's largest diversified natural resources company by market capitalisation. It is headquartered in Melbourne, Australia with its principal offices at 171 Collins Street, Melbourne VIC 3000, Australia.

BHP pioneered the development of an oil and gas industry in Australia with the Bass Strait discovery in 1965. The BHP petroleum business, an operating unit within BHP, has conventional oil and gas assets in the U.S. Gulf of Mexico, Australia, T&T, and appraisal and exploration options in Mexico, T&T, Western U.S. Gulf of Mexico, Eastern Canada, Barbados and Egypt. BHP Petroleum includes BHP Petroleum's interests in its Algerian assets, which BHP is in the process of divesting.

Further details on BHP Petroleum can be found in Part 8 (*Overview of BHP Petroleum*) of this Prospectus.

4 Merger rationale

The Woodside Board believes that the proposed Merger of Woodside and BHP Petroleum is a highly attractive opportunity that is expected to create a top 10 global independent energy company by production and the largest energy company listed on the ASX.[39] In evaluating the Merger and reaching its decisions with respect to the Merger and the Share Sale Agreement, the Woodside Board consulted with Woodside's management and outside legal and financial advisers, and considered a number of factors, including:

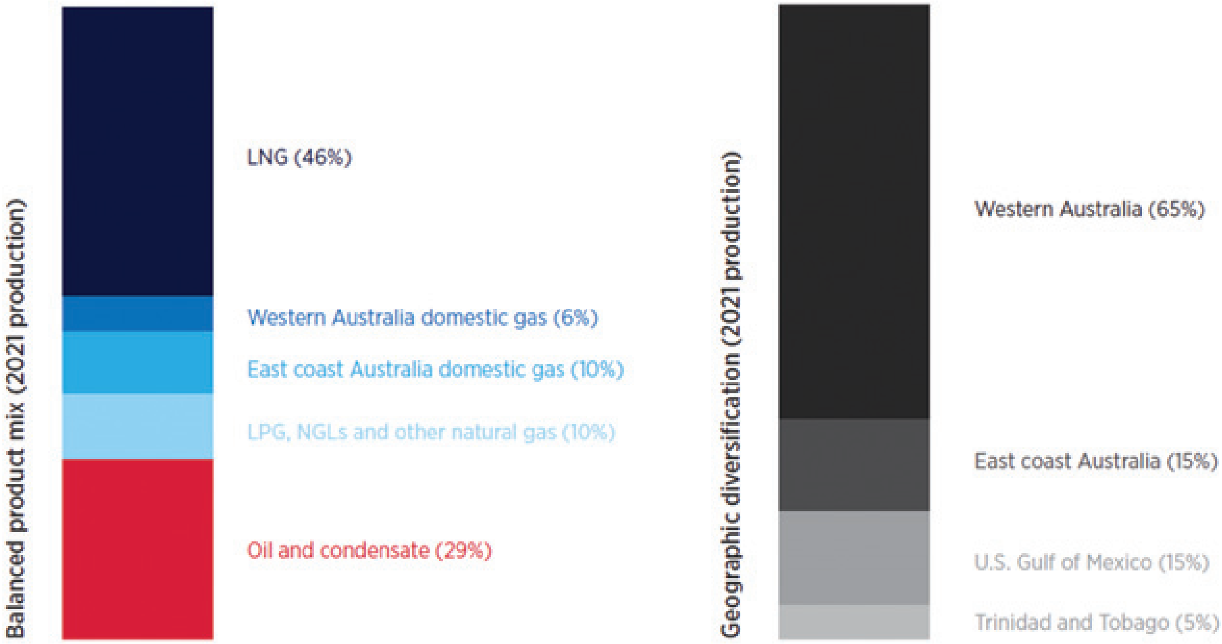
Greater scale and diversity of geographies, products and end markets through an attractive and long-life conventional gas and high-margin oil portfolio

The Merger is expected to deliver benefits for both Woodside Shareholders and Eligible BHP Shareholders by creating a long-life conventional portfolio of scale and diversity of geography, product and end markets.

On a combined basis, as at 30 June 2021 (effective date of the transaction), the Merged Group is expected to consist of:

- Conventional asset base estimated to produce around 193 MMboe (net production);
- Diversified production mix of 46% LNG, 29% oil and condensate and 25% domestic gas and liquids (net production);
- Wide geographic reach with production from Western Australia, East Coast Australia, United States, Gulf of Mexico, and T&T with approximately 95% of production (net production) from Organisation for Economic Co-operation and Development ("**OECD**") nations; and
- 2P reserves of over 3.6 billion boe[40] comprising 79% gas, and 21% liquids.[41] BHP Petroleum volumes for overlapping assets are based on Woodside estimates).

Figure 19 – Merged Group production mix by type and region[42] for the 12 months ended 31 December 2021



[39] Top 10 global independent energy company by hydrocarbon production. Woodside analysis based on the Wood Mackenzie Corporate Benchmarking Tool Q4 2021, 1 December 2021. See the section titled 'Disclaimer and Important Notices' for clarification of independent energy company.

[40] Total barrels of oil equivalent (boe) conversion is based on the following: 5,700 standard cubic feet (scf) of natural gas equals one boe. This conversion ratio is based on the heating value of supplied LNG and domestic pipeline gas. The use of a conversion factor of 6.0 would be more appropriate where the sales product contains more inerts as might be the case with assets that supply pipeline gas with lower heating value requirements. Based on an assessment of past, current and future heating value requirements for gas demand for Woodside's facilities, Woodside believes that a ratio of 5.7 is appropriate

[41] Woodside as at 31 December 2020 and adjusted for half-year production to 30 June 2021. BHP Petroleum as at 30 June 2021. BHP Petroleum volumes for NWS and Greater Scarborough are based on Woodside estimates.

[42] Combined Woodside and BHP Petroleum for the 12 months to 31 December 2021. Excludes Algeria and Neptune production. For comparative purposes, on a Woodside stand-alone basis for the 12 months to 31 December 2021:
Balanced production mix: 78% LNG, 19% Oil and condensate, 3% Western Australia domestic gas, 0% East coast Australia domestic gas and <1% LPG, NGLs and other natural gas. NGLs refer to a mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs mostly include very light hydrocarbons (ethane, propane, or butanes) Geographic diversification: 100% Western Australia.

Strong combination of assets with high growth, margins and reserves life

Strong combination of high-quality assets which are high-growth, high-margin, and long-life underpin the value proposition of the Merged Group.

Complementary combined portfolio cash flows expected to fund shareholder returns and business evolution during the energy transition

Strong Adjusted Operating Cash Flow at a long term US$65 Brent oil price (real 2022) is expected to support continued strong returns to Woodside Shareholders over time. Woodside expects to maintain its focus on disciplined growth investment and continued dividends in line with its stated dividend policy of a minimum of 50% of net profit after tax excluding non-recurring items in dividends. The Woodside Board's dividend payout ratio target is between 50% to 80% of net profit after tax, excluding non-recurring items, subject to market conditions and investment requirements.

Strong growth profile and capacity to pursue competitive oil and gas projects as well as lower-carbon growth options within the portfolio

Woodside believes that the proposed Merger will deliver expanded growth optionality with the flexibility to phase and selectively progress near and longer-term lower carbon options and high-return options.

- Final investment decisions have been made in relation to the Scarborough and Pluto Train 2 developments, including new domestic gas facilities and modifications to Pluto Train 1.
- The Mad Dog Phase 2 (U.S. GOM), Shenzi North (U.S. GOM) and Sangomar Oil Field Development Phase 1 (Senegal) projects remain on budget and on track, and along with significant expansion options, provide opportunity for near- and medium-term growth.
- Longer term embedded options include the Wildling (U.S. GOM), Trion (Mexico), Calypso (T&T) and Browse (Western Australia) projects. These options offer additional potential growth coupled with multiple exploration and new energy opportunities and partnerships, including H2Perth, H2TAS, H2OK and Heliogen.

Proven management and technical capability from both companies

The Merged Group will benefit from the joint management and technical expertise of both companies, led by Meg O'Neill as the Chief Executive Officer and Managing Director.

Woodside believes that the Merged Group will combine leading health, safety, environment and quality ("**HSEQ**") performance, LNG production and marketing, deepwater oil development and production, exploration expertise, and international experience thereby creating a breadth of capabilities and experience in the Merged Group. These capabilities are expected to be further supplemented through investments in technology and lower carbon solutions and strong governance systems.

Upon Implementation, it is intended that an individual will be appointed to the Merged Group Board who currently serves on the BHP Board.

Shared values and focus on sustainable operations, carbon management and ESG leadership

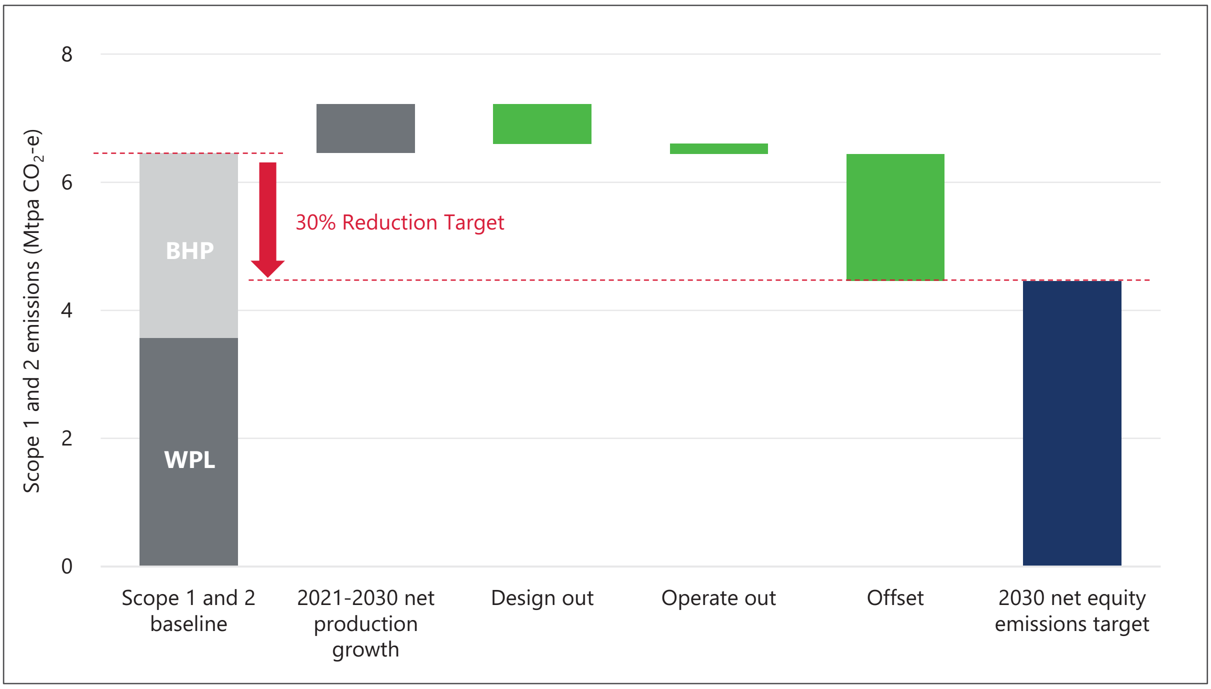
Woodside intends to continue to have a strong focus on safe, sustainable and reliable operations, building on Woodside's and BHP's strong track records.

Woodside also plans to build on Woodside's existing targets for the Merged Group to reduce net equity Scope 1 and 2 emissions by 15% and 30% by 2025 and 2030 respectively, as compared against the gross 2016-2020 annual average baseline, on the pathway to its aspiration of net zero Scope 1 and Scope 2 emissions by 2050 or sooner, applying these to the combined portfolio.

Woodside intends to set emissions reduction targets on an equity basis. This ensures that the scope of emissions reduction targets is aligned with the actual footprint of the Merged Group's investments and its expected use of offsets. Equity emissions reflect the greenhouse gas emissions from operations according to the Merged Group's share of equity in the operation. The equity share reflects economic interest, which is the extent of rights a company has to the risks and rewards flowing from an operation. Woodside intends to set its emissions reduction targets for the Merged Group on a net basis, allowing for both direct emissions reductions from their operations as well as emission reductions achieved from the use of offsets.

Woodside will focus on optimising value and shareholder returns and building and maintaining a lower-carbon, resilient and diversified portfolio which includes oil, natural gas and new energy technologies. The Merged Group is expected to generate significant cash flow this decade that could be used in part to support the development of new energy products and lower carbon solutions including hydrogen, ammonia and carbon capture and storage ("**CCS**").

Figure 20 – Merged Group's net scope 1 and 2 emission reduction targets[43]



This chart shows indicative design out, operate out and offset emissions reductions to achieve Merged Group's net equity Scope 1 and 2 greenhouse gas emissions targets in the year 2030. The values do not represent cumulative abatement over the period leading up to those years.

[43] Baseline is set as the gross average equity Scope 1 and 2 emissions over 2016-2020 and may be adjusted (up or down) for potential equity changes in producing or sanctioned assets, with an FID prior to 2021. Baseline will be adjusted to incorporate combined portfolio.

Synergies and benefits

Woodside has undertaken a review of costs for the Merged Group (benchmarked against industry peer performance) and produced a comprehensive list of synergy opportunities. These opportunities are expected to deliver annual savings in excess of US$400 million per annum (pre-tax 100% basis) comprising, approximately US$120 million of corporate savings, US$80 million of cost savings related to operations of the business, US$150 million in exploration expenditure reduction and $50 million of execution costs savings associated with future growth opportunities. These synergies are expected to be realised progressively and to be implemented by early 2024.

Greater financial resilience

Upon Implementation, the Merged Group's balance sheet is expected to be strengthened by the resilience the merged portfolio delivers through the commodity and investment cycle.

Woodside believes that the Merger of BHP Petroleum and Woodside is expected to create a larger, more financially resilient company, with increased scale and technical depth, enabling the Merged Group to better navigate the energy transition than either Woodside or BHP Petroleum could on a standalone basis. The Merger is expected to provide long term value and unlock synergies in how these assets are managed.

BHP rationale

BHP regularly reviews its portfolio to improve its asset base and optimise capital allocation decisions. In 2021, BHP undertook a strategic review of its petroleum business, including evaluating opportunities to divest its petroleum business to one or more buyers in one or more series of transactions or via a demerger into a newly listed entity. While a demerger would result in a strong and financially viable standalone entity, the BHP Board determined that the Merger was the best alternative for shareholders.

BHP believes that the Merger will deliver substantial value creation for BHP shareholders. Through the combination of two high-quality asset portfolios, the Merged Group is expected to have a high margin oil portfolio, long life LNG assets and the financial resilience to help supply the energy needed for global growth and development over the energy transition. The combined portfolio is also expected to unlock material synergies for shareholders. It will also enable a greater allocation of capital in the portfolio to be directed towards future facing commodities and enhanced shareholder returns.

The Merger also provides BHP shareholders choice about how to weight their exposure to the different investment propositions of BHP (excluding BHP Petroleum) and oil and gas through Woodside (including BHP Petroleum).

Further detail on the profile of the Merged Group can be found in Part 11 (*Overview of the Merged Group*) of this Prospectus.

5 Merger Consideration

If the Merger is implemented, Woodside will acquire 100% of the issued share capital of BHP Petroleum International Pty Ltd in exchange for:

- the Share Consideration: the issue of 914,768,948 New Woodside Shares (assuming that no additional Woodside Shares are issued in connection with a Permitted Equity Raise and no further declaration of Woodside Dividends will occur prior to Implementation) by Woodside to BHP on Implementation, with those New Woodside Shares to be immediately distributed by BHP to, or for the benefit of, BHP Shareholders; and
- the Woodside Dividend Payment, payable by Woodside to BHP on Implementation; and
- any other adjustments to the Merger Consideration payable in accordance with the Share Sale Agreement.

Separately, if required, BHP will pay to Woodside, or Woodside will pay to BHP, the Locked Box Payment on Implementation.

Further information regarding the Share Sale Agreement, the Woodside Dividend Payment and the Locked Box Payment is set out in paragraph 14 of this Part 10 *(Summary of the Merger)* of this Prospectus.

Share Consideration

With respect to the Share Consideration, BHP has provided Woodside with written notice stating that BHP directs Woodside to issue the Share Consideration to BHP, following which BHP will procure that the New Woodside Shares are immediately distributed to Eligible BHP Shareholders (or transferred to the Sale Agent, in the case of New Woodside Shares attributable to Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders).

Upon Implementation, Woodside will issue New Woodside Shares and:

- ensure that each New Woodside Share is unencumbered, fully paid up and ranks equally with existing Woodside Shares;
- procure that all New Woodside Shares are listed for quotation on ASX (or relevant secondary listing exchange); and
- cause a holding statement or allotment confirmation advice to be promptly despatched to each BHP Shareholder and Depositary Interest Holder that has received New Woodside Shares or Depositary Interests (respectively).

Based on the issue of 914,768,948 New Woodside Shares and the number of BHP Shares outstanding on the Last Practicable Date, Eligible BHP Shareholders will be entitled to receive approximately 0.1807 New Woodside Shares for each BHP Share held at the Distribution Record Date (which date will be set by BHP), with their aggregate entitlement to New Woodside Shares rounded down to the nearest whole number of New Woodside Shares. Based on the closing price of Woodside Shares of A$21.18 per share on ASX on 16 August 2021, being the last trading day before the Merger was announced, the Share Consideration implies a total consideration of A$19.375 billion (US$14.213 billion). Based on the closing price on ASX of Woodside Shares of A$22.11 per share on 19 November 2021, being the last trading day before the Share Sale Agreement was entered into, the Share Consideration amounts to a total consideration of A$20.226 billion (US$14.712 billion). Based on the closing price on ASX of Woodside Shares of A$33.20 per share on the Last Practicable Date, the Share Consideration amounts to a total consideration of A$30.370 billion (US$22.696 billion).

The New Woodside Shares to be issued as Share Consideration will represent approximately 48% of the shares on issue in the Merged Group upon Implementation, with Existing Woodside Shareholders owning approximately 52% of the Merged Group.[44]

From the date of Implementation, the New Woodside Shares received as part of the Merger Consideration will be fully paid and rank equally with existing Woodside Shares.

Following Implementation, the Woodside Shares will continue to be listed on ASX.

BHP ADS Holders will be issued New Woodside Shares in the form of Woodside ADSs, each representing a Woodside Share. Woodside will file with the SEC the U.S. Registration Statement in respect of the registration of the distribution of the New Woodside Shares and a registration statement on Form F-6 (the **"Form F-6 Registration Statement"**) for the issue of the Woodside ADSs under U.S. securities laws prior to the annual general meeting. In addition, Woodside has applied to list the Woodside ADSs on the NYSE under the symbol "WDS." See Part 19 (*Depositary Interests*) of this Prospectus.

Woodside will also apply for Admission of the Woodside Shares in the United Kingdom on the LSE under a standard listing.

44 In each case assuming that no additional Woodside Shares are issued in connection with a Permitted Equity Raise and no further declaration of Woodside Dividends will occur prior to Implementation

Woodside Dividend Payment and Locked Box Payment

Separate to the Share Consideration, on Implementation:

- Woodside will pay the Woodside Dividend Payment to BHP; and
- if required, BHP will pay to Woodside, or Woodside will pay to BHP, the Locked Box Payment.

The Woodside Dividend Payment is, in effect, the payment to BHP of a cash amount at Implementation representing the cash dividend that would have been received (between the Effective Time and Implementation) by BHP Shareholders if they had been issued the Share Consideration at the Effective Time.

The Locked Box Payment is a payment from BHP to Woodside at Implementation representing the positive net cash flow generated by BHP Petroleum (adjusted for permitted adjustments) following the Effective Time (or, if that amount were negative, Woodside will be required to make a cash payment to BHP at Implementation).

Further information regarding the Share Sale Agreement, the Woodside Dividend Payment and the Locked Box Payment is set out in paragraph 14 of this Part 10 *(Summary of the Merger)* of this Prospectus.

6 Conditions of the Merger

Under the Share Sale Agreement, Implementation is conditional on the satisfaction (or, where permitted, waiver) of the following conditions by 30 June 2022 (or an agreed later date):

- **FIRB Approval***:* BHP obtaining approval from FIRB if BHP determines (acting reasonably) that it will likely be required in connection with the Merger.
- **ACCC Approval**: Woodside being advised by the ACCC that it does not object to, or propose to take any action in relation to, the Merger.
- **NOPTA Approval***:* Woodside obtaining approval from NOPTA to Implement the Merger.
- **Woodside Shareholder Approval***:* Woodside Shareholders approving the Merger Resolution.
- **ASIC, ASX, SARB and JSE**: BHP and Woodside obtaining all relief, waivers, confirmation, exemptions, consents or approvals and doing all other acts necessary, or which BHP or Woodside (both acting reasonably) desire, from ASIC, ASX, SARB and JSE to Implement the Merger.
- **HSR Act Clearance**: Expiration of the waiting period under the HSR Act or earlier termination without challenge by the U.S Department of Justice or the Federal Trade Commission.
- **CFIUS Approval**: Woodside obtaining certain notices from CFIUS permitting the Merger.
- **Official Quotation**: Woodside not receiving an indication from ASX that it will not grant permission for the official quotation of the New Woodside Shares.
- **Independent Expert's Report**: Independent Expert issuing a report concluding the Merger is in the best interests of Woodside Shareholders, and such conclusion is not changed or withdrawn before the Woodside Shareholder Approval is obtained.
- **Restructure***:* BHP completing the Restructure, being the transfer, liquidation or removal of certain BHP Petroleum Group Members.
- **U.S. Registration Statements**: certain registration statements filed by Woodside relating to the New Woodside Shares and New Woodside ADSs being declared effective by the SEC, and no stop order suspending the effectiveness of those registration statements has been issued, and no proceedings for that purpose have been commenced, by the SEC.
- **Other Competition Approvals**: Woodside obtaining competition clearance in relation to the Merger from the relevant authorities in T&T, the People's Republic of China, Japan, Mexico, Barbados and Vietnam.
- **No Injunction or Order**: No court or governmental agency enacting, issuing or enforcing any law or governmental order that restrains, enjoins or otherwise prohibits consummation of the Merger and all regulatory approvals being in full force and effect.

As at the date of this Prospectus all Conditions listed above that require a positive action or event in order to be satisfied have been satisfied or waived except for the following:

- Woodside Shareholder Approval;
- Woodside obtaining approval from NOPTA to Implement the Merger;
- BHP completing the Restructure; and
- the U.S. registration statements to be filed by Woodside in connection with the Merger being declared effective by the SEC.

7 Termination of the Merger

Either BHP or Woodside may terminate the Share Sale Agreement where a Condition set out in paragraph 6 of this Part 10 *(Summary of the Merger)* of this Prospectus fails to be satisfied (or waived, if permitted) by 30 June 2022 (or an agreed later date). If the Share Sale Agreement is terminated prior to Implementation, then the Merger and Admission will not proceed.

Woodside may terminate the Share Sale Agreement (and therefore the Merger) prior to Implementation in the following circumstances:

- BHP materially breaches its obligations under the Share Sale Agreement and fails to remedy the breach.
- An unremedied breach of a BHP warranty given to Woodside has occurred, or will otherwise occur at Implementation, and the loss reasonably expected to flow from the breach would exceed US$500,000,000.
- A majority of the members of the Woodside Board fail to recommend, or change, withdraw or qualify (except for customary qualifications) their recommendation, that Woodside Shareholders vote in favour of the Merger, or the Woodside Board recommends a superior proposal, in relation to the Woodside Group, in circumstances where the Woodside Board is expressly permitted by the terms of the Share Sale Agreement to do so (e.g. where the Independent Expert's Report concludes that the Merger is not in the best interests of Woodside Shareholders).
- Half or more of the BHP Board publicly cease supporting the Merger, including as a result of a BHP Petroleum competing proposal.
- A material adverse change occurs in relation to BHP Petroleum.
- A 'prescribed occurrence' occurs in relation to BHP Petroleum (e.g. changes to share capital structure, amendments to constitution etc).
- An 'insolvency event' occurs in relation to BHP.
- BHP Petroleum's proven and probable reserves calculated in accordance with the Share Sale Agreement (applying SPE PRMS methodology) are reduced by 15% or more from 1,010.7 MMboe (subject to certain exclusions).

BHP may terminate the Share Sale Agreement (and therefore the Merger) prior to Implementation in the following circumstances:

- Woodside materially breaches its obligations under the Share Sale Agreement and fails to remedy the breach.
- An unremedied breach of a Woodside warranty given to BHP has occurred, or will otherwise occur at Implementation, and the loss reasonably expected from the breach would exceed US$500,000,000.
- Half or more of the Woodside Board members either change, withdraw or qualify their support or recommendation that Woodside Shareholders vote in favour of the Merger, or make a public statement indicating that they no longer support or intend to recommend the Merger or recommend, support or endorse any competing proposal for Woodside.
- BHP or the majority of the BHP Board announce an intention, or BHP enters into an agreement, to pursue a superior proposal in relation to BHP Petroleum in circumstances where Woodside has not made a counterproposal, or Woodside has made a counterproposal and the BHP Board (acting reasonably and in good faith) has determined that the counterproposal would not provide an equivalent or superior outcome for BHP Shareholders.
- A material adverse change occurs in relation to the Woodside Group.

- A 'prescribed occurrence' occurs in relation to the Woodside Group (e.g. changes to share capital structure, amendments to constitution etc).
- An 'insolvency event' occurs in relation to Woodside.
- The Woodside Group's credit rating is, or is reasonably likely to be, downgraded to BB+ or Ba1 or lower.
- A credit rating assessment undertaken prior to Implementation indicates a likely credit rating for Woodside after Implementation of BB+ or Ba1 or lower
- Woodside's proven and probable reserves calculated in accordance with the Share Sale Agreement (applying SPE PRMS methodology) are reduced by 158.33 MMboe or more from 1,055.5 MMboe (subject to certain exclusions).

Each of Woodside and BHP have agreed to pay a reimbursement fee of US$160 million in certain circumstances. The reimbursement fee is not payable if the Merger is implemented. Receipt of the reimbursement fee is the sole and exclusive remedy under the Share Sale Agreement of the party claiming the reimbursement fee. See paragraph 14 of Part 10 *(Summary of the Merger)* of this Prospectus for further information.

8 Woodside Shareholder Approval

ASX Listing Rule 7.1 imposes a limit on the number of equity securities (e.g. shares or options to subscribe for shares) which an ASX listed company can issue without shareholder approval. In general terms, a company may not, without prior shareholder approval, issue, or agree to issue, equity securities if the equity securities will in themselves or when aggregated with the securities issued by the company during the previous 12 months exceed 15% of the number of fully paid ordinary shares on issue at the commencement of that 12 month period.

If implemented, the Merger would result in Woodside exceeding the 15% threshold as a result of the issue of the New Woodside Shares comprising the Share Consideration. Therefore, the issuance by Woodside of the New Woodside Shares is subject to the approval by Woodside Shareholders of the Merger Resolution to be proposed at the Woodside Shareholders' Meeting. The passing of the Merger Resolution constitutes the Woodside Shareholder Approval and is one of the Conditions that is required to be satisfied before the Merger can be implemented. Accordingly, the Admission is conditional on the passing of the Merger Resolution.

Woodside Shareholders on the register as at 5.00pm (Perth time) on 17 May 2022 will be entitled to vote on the Merger Resolution, either in person or by proxy, at the Woodside Shareholders' Meeting to be held at 10.00am (Perth time) on 19 May 2022. For the Merger Resolution to be passed, the number of votes cast at the Woodside Shareholders' Meeting (by Woodside Shareholders attending in person or by proxy) in favour of the resolution must exceed the number of votes cast at the Woodside Shareholders' Meeting (by Woodside Shareholders attending in person or by proxy) against the resolution.

9 Regulatory matters

Regulatory Approvals Under the Share Sale Agreement

The regulatory authorisations, approvals or consents required under the Share Sale Agreement are Conditions and are set out in paragraph 6 of Part 10 *(Summary of the Merger)* of this Prospectus.

As at the date of this Prospectus, all required regulatory approvals have been obtained, except for the NOPTA approval (as described in paragraph 6 of Part 10 (*Summary of the Merger*), and the U.S. registration statements to be filed by Woodside in connection with the Merger being declared effective by the SEC.

In addition, Woodside must use its reasonable endeavours to procure that prior to Implementation:

- the FCA has confirmed that the application for admission of the Woodside Shares to the Official List is approved and will be become effective as soon as a dealing notice has been issued by the FCA and any listing conditions have been satisfied;
- the LSE has confirmed (and not withdrawn such confirmation) that the Woodside Shares will be admitted to trading on the LSE Main Market for listed securities; and
- the Woodside Shares represented by Woodside ADSs to be issued as Share Consideration have been approved for listing on the NYSE.

Summary of Regulatory Waivers and Relief

FIRB

BHP has determined that the approval of FIRB is not required to implement the Merger, and has waived this Condition.

ASIC

ASIC has granted BHP relief so that the takeover provisions in the Corporations Act will not apply to the acquisition by BHP of the New Woodside Shares in circumstances where BHP holds the Share Consideration momentarily before distributing the New Woodside Shares to Eligible BHP Shareholders. Woodside has also obtained relief from ASIC in relation to the technical application of section 606 of the Corporations Act to Woodside, resulting from the application of certain contractual rights in the Share Sale Agreement to the Share Consideration.

ASX

ASX listing rule 11.1 gives ASX discretion to require an entity making a significant change to the nature or scale of its activities to obtain shareholder approval in respect of the change, or to meet the requirements in Chapters 1 and 2 of the ASX Listing Rules as if it were applying for admission to the official list of ASX. ASX has given in-principle advice to Woodside and BHP (as appropriate) that:

- ASX listing rule 11.1.2 does not require Woodside or BHP to obtain shareholder approval of the Merger;
- ASX listing rule 11.1.3 does not require Woodside or BHP to meet the requirements in Chapters 1 and 2 of ASX listing rules;
- Woodside shareholders that also hold BHP shares will not be precluded from voting on the Merger Resolution; and
- ASX listing rule 10.11 does not preclude any Woodside Director who holds BHP Shares from receiving New Woodside Shares without a separate shareholder approval.

JSE, SARB

The approval of the Johannesburg Stock Exchange ("**JSE**") and the South African Reserve Bank is required in connection with BHP's distribution of the Share Consideration to BHP Shareholders that hold their BHP Shares through the JSE. The JSE and SARB have given to BHP the requisite approvals permitting the distribution, including in relation to the treatment of BHP Shareholders holding through JSE as Ineligible Foreign BHP Shareholders.

10 Risks

In considering the Merger, investors should be aware that there are a number of risk factors, both general in nature and those specific to the Merger, the Merged Group and Woodside Shares. Part 2 (*Risk Factors*) of this Prospectus outlines the key:

- risks relating to the Merged Group (see paragraph 1 of Part 2 (*Risk Factors*) of this Prospectus);
- risks relating to Implementation of the Merger (see paragraph 2 of Part 2 (*Risk Factors*) of this Prospectus); and
- risks relating to Woodside Shares (see paragraph 3 of Part 2 (*Risk Factors*) of this Prospectus).

As both companies have significant exposure to the oil and gas sector, a number of the risks relating to the Merged Group are, or will be, risks to which either or both of Existing Woodside Shareholders and BHP Shareholders are already exposed to, and will continue to be exposed to, even if the Merger does not proceed. Existing Woodside Shareholders already bear these risks to a greater degree than BHP Shareholders due to Woodside's concentration in the oil and gas sector. If the Merger is implemented, the nature and scale of the Merged Group's business will be different from that of either Woodside or BHP Petroleum.

These risks, uncertainties and other important factors include, among others:

- fluctuations in the price of crude oil and a substantial or extended decline in crude oil prices;
- fluctuations in LNG market conditions, prices and buyer preferences, and any material and sustained LNG price deterioration or change in LNG buyer preferences;
- the impacts of an epidemic or outbreaks of an infectious disease, for example the ongoing impacts of COVID-19;
- increased proportion of shorter-term contracts and volatile spot pricing with respect to LNG;
- conducting a majority of major projects and operations through joint ventures, which may limit the Merged Group's degree of control and ability to identify and manage risks;
- uncertainties and operating risks as a result of significant funds being invested in a variety of exploration, development projects, production and restoration activities;
- reliance on third parties to advance proposed developments and the risk that the Merged Group may not reach agreements with third parties;
- vulnerabilities related to having a substantial majority of sales of LNG being to a limited number of customers in Japan;
- risk of incurring losses due to counterparty exposures;
- the need to acquire or discover additional proved reserves or to develop existing, acquired or developed reserves to avoid a decline in proved reserves and production;
- failure to find reserves that can be commercialised successfully;
- limitations on the Merged Group's access to capital or a failure in financial risk management;
- operating hazards and natural disasters;
- extensive government regulation, including the ability to obtain regulatory approvals;
- governmental and sovereign risk;
- operating in locations suffering from political, legal and other uncertainties, including risk of governmental and business corruption and foreign sanctions;
- revocation, failure to renew or alteration of the terms of the Merged Group's permits;
- risks from oversight and review by competition regulatory bodies;
- enhanced public and private focus on climate change, greenhouse effects and proposed or contemplated laws and regulations relating to carbon emissions;
- uncertainty of estimated petroleum reserves;
- competition in the exploration, production and marketing of products;
- exchange rate risks;
- intentional or unintentional disruption of the Merged Group's information technology systems;
- litigation and arbitration;
- shortage of skilled labour and construction materials, equipment and supplies; and
- other factors referred to in this Prospectus. See Part 2 (*Risk Factors*) of this Prospectus.

These risk factors do not take into account the individual investment objectives, financial situation, position or particular needs of individual investors. Any investor who does not understand any part of this Prospectus (including the risk factors set out in Part 2 (*Risk Factors*) of this Prospectus) should consult their legal, financial, taxation or other professional adviser.

Investors should carefully consider the risk factors discussed in Part 2 (*Risk Factors*) of this Prospectus, as well as the other information contained in this Prospectus.

11 Board / Director recommendations

After carefully considering all aspects, benefits and risks of the Merger and the Independent Expert's Report (including the Independent Technical Specialist Report), the Woodside Directors unanimously:

- support the Merger; and
- recommend that Woodside Shareholders vote in favour of the Merger Resolution,

in the absence of a superior proposal and subject to the Independent Expert maintaining its conclusion that the Merger is in the best interests of Woodside Shareholders.

Each Woodside Director intends to vote in favour of the Merger Resolution in respect of any Woodside Shares they hold or control, in the absence of a superior proposal and subject to the Independent Expert maintaining its conclusion that the Merger is in the best interests of Woodside Shareholders. In reaching their recommendation, the Woodside Directors have considered a range of factors, including the potential for Existing Woodside Shareholders to share in the potential value creation from the expected diversification, growth and scale of the Merged Group.

12 Independent Expert Conclusion

To assist Woodside Shareholders to assess the Merger and consider whether to vote in favour of the Merger Resolution, Woodside appointed the Independent Expert, KPMG, to prepare the Independent Expert's Report.

The Independent Expert has concluded that the Merger is in the best interests of Woodside Shareholders in the absence of a superior offer.

13 Material Tax Considerations Summary

A high-level summary of the tax outcomes for certain Eligible BHP Shareholders and BHP ADS Holders that are tax resident in Australia, the United Kingdom, or the United States is outlined below and should be read in conjunction with the Sections referred to for each jurisdiction. The summary relating to the holding and disposal of Woodside Shares will also apply to Woodside shareholder more generally:

Implementation and receipt of New Woodside Shares

Tax resident and taxing jurisdiction	Tax consequence	Refer
Australia	On the basis that demerger tax roll-over relief does not apply, the Special Dividend will have no impact on the cost base and reduced cost base of your BHP Shares. You should include the amount of the Special Dividend in your assessable income in the income year in which you receive the Special Dividend. BHP intends to fully frank the Special Dividend and, accordingly the Special Dividend will have accompanying franking credits. The tax treatment of these franking credits to you will depend on the satisfaction of certain integrity rules as well as your tax profile.	Paragraph 2, Part 20

Tax resident and taxing jurisdiction	Tax consequence	Refer
United States	Under US federal income tax laws and subject to the Passive Foreign Investment Company ("**PFIC**") rules discussed below, if you are a US Holder, the Special Dividend paid by BHP will be subject to United States federal income taxation. If you are a non-corporate US Holder, if the Special Dividend constitutes qualified dividend income it will be taxable to you at the preferential rates applicable to long-term capital gains provided that you hold the Limited Shares or BHP ADSs for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meet other holding period requirements. The receipt of the Special Dividend should not impact a U.S. holder's basis in its BHP Shares or BHP ADSs. No Australian dividend withholding tax ("**DWT**") arises where the Special Dividend is fully franked.	Paragraph 3, Part 20
United Kingdom	The Special Dividend should not give rise to a disposal of an Eligible BHP Shareholder's BHP shares nor a reduction in their existing base cost in those shares. For UK income tax purposes, the Special Dividend should form part of your total income for income tax purposes and will represent the highest part of that income. For UK corporation tax purposes, if you are a "small company" (for the purposes of UK taxation of dividends) you will not generally be subject to tax on the Special Dividend received from BHP. Other BHP Shareholders within the charge to UK corporation tax will not be subject to tax on the Special Dividend from BHP so long as the Special Dividend falls within an exempt class and certain other conditions are met. No Australian DWT arises where the Special Dividend is fully franked.	Paragraph 1, Part 20

Holding of Woodside Shares

Tax resident and taxing jurisdiction	Tax consequence	Refer
Australia	You will be required to include dividends in respect of Woodside Shares in your assessable income in the income year in which the dividends are received. Dividends may be franked to the extent determined by Woodside. The tax treatment of these franking credits to you will depend on the satisfaction of certain integrity rules as well as your tax profile.	Paragraph 2, Part 20

Tax resident and taxing jurisdiction	Tax consequence	Refer
United States	Under US federal income tax laws and subject to the PFIC rules discussed below, if you are a US Holder, dividends paid by Woodside will be subject to United States federal income taxation. If you are a non-corporate US Holder, dividends that constitute qualified dividend income will be taxable to you at the preferential rates applicable to long-term capital gains provided that Woodside Shares and Woodside ADSs are readily tradable on an established securities market in the U.S. or that Woodside is eligible for certain benefits under the tax treaty between the United States and Australia and that certain holding period and other requirements are met. No Australian DWT arises where dividends are fully franked or declared to be conduit foreign income by Woodside.	Paragraph 3, Part 20
United Kingdom	For UK income tax purposes, all dividends received should form part of your total income for income tax purposes and will represent the highest part of that income. For UK corporation tax purposes, if you are a "small company" (for the purposes of UK taxation of dividends) you will not generally be subject to tax on dividends received from Woodside. Other New Woodside Shareholders within the charge to UK corporation tax will not be subject to tax on dividends from Woodside so long as the dividends fall within an exempt class and certain other conditions are met. No Australian DWT arises where dividends are fully franked or declared to be conduit foreign income by Woodside.	Paragraph 1, Part 20

Disposal of Woodside Shares

Tax resident and taxing jurisdiction	Tax consequence	Refer
Australia	The first element of the cost base and reduced cost base of Woodside Shares you receive as a result of the Merger should be equal to the market value of the Woodside Shares at the time of the transfer of Woodside Shares to you. On disposal of Woodside Shares, you will make a capital gain if the capital proceeds from the disposal of Woodside Shares exceed the cost base of the Woodside Shares sold. You will make a capital loss if the capital proceeds are less than the reduced cost base of the Woodside Shares sold. You may be entitled to a CGT discount in certain circumstances to reduce any capital gain (after offsetting available capital losses).	Paragraph 2, Part 20

Tax resident and taxing jurisdiction	Tax consequence	Refer
United States	For Eligible BHP Shareholders in the U.S. who receive Woodside Shares as a result of the Merger, your aggregate tax basis in New Woodside Shares or New Woodside ADSs that you receive should generally be the fair market value (expressed in U.S. dollars) of the New Woodside Shares or New Woodside ADSs on the date of the distribution of Special Dividend (i.e. the time of receipt of New Woodside Shares). Subject to the PFIC rules discussed below, you may recognise a capital gain or loss for United States federal income tax purposes equal to the difference between the US dollar value of the amount that you realise and your tax basis, determined in U.S. dollars in respect of the disposal of your Woodside Shares or Woodside ADSs. No tax should generally be payable in Australia in respect of the disposal of Woodside Shares by US tax residents, unless the Woodside Shares constitute "indirect Australian real property interests".	Paragraph 3, Part 20
United Kingdom	For the purpose of UK capital gains tax and UK corporation tax on chargeable gains, an Eligible BHP Shareholder who holds New Woodside Shares as a result of the Merger, should have a base cost in their New Woodside Shares equal to the market value of the New Woodside Shares at the date of distribution (i.e. at the time of receipt of New Woodside Shares). If you dispose of any Woodside Shares, you should make a chargeable gain (or allowable loss) for the purposes of UK CGT or UK corporation tax, depending on your circumstances and subject to any available exemption or relief. No tax should generally be payable in Australia in respect of the disposal of Woodside Shares by UK tax residents, unless the Woodside Shares constitute "indirect Australian real property interests".	Paragraph 1, Part 20

14 Key Documents

14.1 Scarborough Put Option Deed

On 17 August 2021, Woodside Energy Ltd, Woodside Energy Scarborough Pty Ltd and certain subsidiaries of BHP entered into the Scarborough Put Option Deed under which Woodside granted to BHP an option to sell to Woodside its interests in the Scarborough, Jupiter and Thebe Projects on agreed terms and conditions. See paragraph 17 of Part 21 (*Additional Information*) of this Prospectus.

14.2 Integration and Transition Services Agreement

On 22 November 2021 (at the same time as the Share Sale Agreement), Woodside and BHP entered into the Integration and Transition Services Agreement which provides for the terms upon which:

- activities will be undertaken prior to Implementation to separate BHP Petroleum from the BHP Group and to facilitate the integration of BHP Petroleum into the Woodside Group on and from Implementation; and
- BHP will provide transition services to the Woodside group following Implementation.

See Part 21 (*Additional Information*) of this Prospectus for further information.

14.3 Share Sale Agreement

On 22 November 2021, Woodside and BHP entered into the Share Sale Agreement on the key terms set out below to give effect to the Merger, pursuant to which BHP agreed to sell and Woodside agreed to buy the entire issued share capital of BHP Petroleum International Pty Ltd in exchange for the Merger Consideration, including the issue of New Woodside Shares as the Share Consideration.

The Merger effected under the Share Sale Agreement will have an effective time of 11.59p.m. on 30 June 2021 (Melbourne time) (the "**Effective Time**"), with contractual mechanics giving Woodside and BHP economic outcomes as if 100% of the share capital in BHP Petroleum International Pty Ltd had been acquired by Woodside at the Effective Time.

Conditions

The Conditions are set out in paragraph 6 of Part 10 *(Summary of the Merger)* of this Prospectus, together with a statement as to the status of the Conditions.

Merger Consideration

The Merger Consideration payable by Woodside for the acquisition of BHP Petroleum includes the Share Consideration, being the issue of New Woodside Shares representing approximately 48% of Woodside's share capital (on a post-issue basis) to, or as directed by, BHP.

The Share Consideration will be supplemented by the Woodside Dividend Payment, being in effect the payment to BHP of a cash amount at Implementation representing the cash dividend that would have been received (post Effective Time and pre-Implementation) by holders of the Share Consideration if they had been issued the Share Consideration at the Effective Time.

To give effect to the Effective Time principle, BHP will be required to pay Woodside the Locked Box Payment, being a payment at Implementation representing the net cash flow generated by BHP Petroleum following the Effective Time (or, if that amount were negative, Woodside will be required to make a cash payment to BHP at Implementation).

Distribution of New Woodside Shares

BHP must declare or determine a dividend, initiate a reduction of capital or pursue a combination of the two (as determined by BHP) in order to facilitate the distribution of the New Woodside Shares to Eligible BHP Shareholders (or transferred to the Sale Agent, in the case of New Woodside Shares attributable to Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders). The Share Sale Agreement contains certain mechanical arrangements to facilitate dealing with the Ineligible Foreign BHP Shareholders, any Relevant Small Parcel BHP Shareholders and the BHP Group's American Depositary Receipts programme.

For so long as BHP holds the New Woodside Shares (if at all), BHP undertakes not to dispose of the New Woodside Shares (otherwise than in accordance with the Share Sale Agreement) or exercise voting power in respect of the New Woodside Shares.

Merger Implementation and pre-Implementation conduct provisions

Woodside and BHP must use reasonable endeavours to comply with and take all necessary steps and exercise all rights necessary to implement the Merger, in accordance with certain timetable requirements as set out in the Share Sale Agreement. Woodside and BHP may agree to any necessary extension to the timetable to ensure relevant steps are completed as soon as reasonably practicable.

In circumstances where various specified critical separation activities will not be completed prior to the anticipated date for Implementation, Woodside and BHP must negotiate in good faith and act reasonably to agree actions to enable completion of such activities or determine any necessary transitional arrangements that would otherwise enable Implementation to occur. Failing such agreement, both Woodside and BHP have the right to defer Implementation (to not later than 1 August 2022) for such period that is necessary to allow such activities to complete or to develop transitional arrangements that would otherwise enable Implementation to occur.

Woodside and BHP have agreed to take a variety of steps to assist the other with the Merger, and to generally advance and implement the Merger and associated matters. Woodside and BHP each give certain commitments in relation to, amongst other things, engagement with regulatory bodies, provision of information in connection with the preparation of public documents and the facilitation of listings on securities exchanges.

Until Implementation, Woodside must carry on, and BHP must ensure that BHP Petroleum carries on, their respective businesses in the ordinary and normal course, unless otherwise permitted or required under the Share Sale Agreement.

BHP has also undertaken to, among other things, complete the Restructure (as described in the following section) to eliminate certain intra-group funding arrangements and take all other prescribed separation steps, including complying with the Integration and Transition Services Agreement (summarised in paragraph 17 of Part 21 *(Additional Information)* of this Prospectus). Woodside and BHP have agreed, subject to applicable laws, to work together and plan for Implementation.

Woodside and BHP have also agreed to customary wrong pockets provisions, to ensure that Woodside obtains the benefit of assets relating to the BHP Petroleum business and BHP retains the benefit of assets relating to BHP's other businesses.

Woodside and BHP have identified certain contracts, consents and authorisations of BHP Petroleum which contain change of control provisions, unilateral termination rights, notification rights, pre-emptive rights or tag-along rights which may be required by, triggered by, or exercised in response to, Implementation. Woodside and BHP will take the agreed course of action in connection with the obtaining of consents or confirmations under these identified contracts, consents and authorisations in relation to the Merger. Provided that BHP has complied with its obligations under the Share Sale Agreement in relation to obtaining such consents or confirmations, a failure by BHP to obtain such consents or confirmations (or the exercise of a termination or pre-emptive right by a counterparty) will not result in a claim by Woodside against BHP under the Share Sale Agreement, delay or prevent Implementation, nor result in an adjustment to the Purchase Price.

Prior to Implementation, Woodside must take all reasonably necessary actions to allow any bank guarantees, indemnities, guarantees or similar support given by BHP Group Members (other than BHP Petroleum Group Members) to a third party, to the extent that they relate to the existing obligations of BHP Petroleum, to be released by having a Woodside Group Member provide replacement support. If such arrangements have not been replaced by Implementation, Woodside must indemnify BHP and the relevant BHP Group Member in respect of such arrangements.

Restructure of BHP Petroleum

In connection with the Merger, BHP has undertaken to complete a restructure involving the transfer out of BHP Petroleum of the Restructure Entities (the "**Restructure**"). The Restructure is required to be completed prior to Implementation in accordance with the Share Sale Agreement.

In addition, BHP has undertaken to eliminate certain intra-group funding arrangements, and to take all other prescribed separation steps, prior to Implementation including complying with the Integration and Transition Services Agreement.

Warranties and indemnities

BHP has given certain warranties regarding the BHP Petroleum business in favour of Woodside, including in respect of title and capacity, corporate group structure, accounts, business records, ownership of assets, petroleum titles, contracts, environmental matters, real property, information technology, intellectual property, litigation and authorisations, anti-bribery and corruption, divested, non-oil and gas operations and relinquished assets, sanctions and export controls, employees, solvency, insurance, taxes and duties, and disclosure materials.

Woodside has given certain warranties regarding its business in favour of BHP which are generally consistent with (but more limited than) the warranties given by BHP.

Woodside and BHP have each agreed to indemnify the other against any loss incurred as a result of a breach of warranty. These indemnities are the sole remedy for a breach of warranty under the Share Sale Agreement.

From Implementation, BHP is not liable for any claim relating to certain decommissioning liabilities and environmental liabilities of BHP Petroleum, other than to the extent the relevant loss is or could reasonably otherwise be, subject to a warranty or indemnity claim by Woodside.

Woodside has agreed to indemnify BHP from, among other things:

- decommissioning liabilities and environmental liabilities relating to or arising from the BHP Petroleum business;
- breaches or contraventions of laws, contracts or authorisations relating to BHP Petroleum; and
- any regulatory action taken in connection with the public documents to be issued by Woodside in relation to the Merger.

BHP has agreed to indemnify Woodside from, among other things:

- any regulatory action taken in connection with the public documents to be issued by BHP in relation to the Merger;
- claims in respect of certain entities and assets (including non-oil and gas operations of BHP Petroleum) that will be restructured out of BHP Petroleum before Implementation ("**Excluded / Divested Assets Indemnity**");
- claims under certain divestment agreements relating to assets that no longer form part of BHP Petroleum ("**Third Party Divestment Claims Indemnity**");
- taxes and duties payable or incurred by BHP Petroleum prior to the Effective Time or otherwise in respect of certain assets; and
- for the usage as part of the Restructure of U.S. net operating losses of BHP Petroleum, at the rate of US$0.05 per US$1.00 of net operating losses used above US$1.2 billion ("**U.S. NOL Indemnity"**).

The respective warranties and indemnities arrangements are subject to a limitations and qualifications regime that is in a customary form, including in respect of time limits, monetary caps, minimum claim thresholds, qualifiers for awareness and disclosed matters, and offsets for other claims and benefits that are available to the party claiming under the warranty or indemnity. The nature and extent of limitations varies depending on the type of claim being made by Woodside against BHP:

- claims under the tax indemnity, tax warranties, title and capacity warranties and the U.S. NOL Indemnity must be notified within 7 years of Implementation, and are subject to a maximum monetary limit of US$16 billion. All other warranty claims must be notified within 18 months of Implementation and are subject to a maximum monetary limit of US$2.4 billion; and
- claims under the Third Party Divestment Claims Indemnity have no notification time limit, while claims under the Excluded / Divested Assets Indemnity must be notified within 3 years of Implementation. Claims under both of these indemnities are subject to a maximum monetary limit of US$16 billion.

Generally reciprocal arrangements exist in respect of claims made by BHP against Woodside, with the necessary changes.

Board recommendation

A majority of the Woodside Board must recommend that Woodside Shareholders vote in favour of the Merger Resolution subject to the Independent Expert appointed by Woodside concluding (and continuing to conclude) that the Merger is in the best interests of Woodside Shareholders. Woodside must ensure that half or more of the Woodside Board do not change, withdraw or qualify their recommendation to vote in favour of the Merger Resolution, unless:

- the Independent Expert appointed by Woodside concludes (including in any updated report) that the Merger is not in the best interests of Woodside Shareholders; or
- the Woodside Board agrees to, or supports, a "Woodside Group Superior Proposal" (as that term is defined in the Share Sale Agreement).

Exclusivity

Woodside and BHP have agreed to comply with certain exclusivity arrangements from the date of the Share Sale Agreement until Implementation (or the earlier termination of the Share Sale Agreement) ("**Exclusivity Period**"). During the Exclusivity Period, BHP must not, and must ensure its related persons do not:

- solicit, invite, encourage or initiate any inquiry, expression of interest, offer, proposal or discussion by any person in relation to an actual or potential BHP Competing Proposal;

- participate in or continue any negotiations or discussions with respect to any inquiry, expression of interest, offer, proposal or discussion by any person to make a BHP Competing Proposal;
- negotiate, accept or enter into, or offer or agree to negotiate, accept or enter into, any agreement, arrangement or understanding regarding a BHP Competing Proposal;
- disclose or otherwise provide any material non-public information about the business or affairs of BHP Petroleum to a third party with a view to obtaining, or which would be reasonably expected to encourage, a BHP Competing Proposal; or
- communicate to any person an intention of doing any of the above.

The exclusivity commitments (other than the general "no shop" provisions) do not prohibit any action or inaction by BHP or its related persons in relation to a BHP Competing Proposal if compliance with the commitments would, in the opinion of the BHP Board, constitute or be reasonably likely to constitute a breach of the duties of the directors of BHP provided that:

- the BHP Competing Proposal was not brought about by a breach of BHP's exclusivity commitments; and
- BHP notifies Woodside of any action or inaction by BHP or its related persons in reliance on this exception.

Woodside has reciprocal exclusivity commitments under the Share Sale Agreement in relation to any actual or potential Woodside Competing Proposal.

Woodside matching right

BHP must not enter into any legally binding agreement, arrangement or understanding pursuant to which a third party proposes to undertake or give effect to a BHP Competing Proposal, and must procure that none of the directors of BHP change, withdraw or qualify its or their support for the Merger, unless:

- the BHP Board acting in good faith and in order to satisfy what the members of the BHP Board consider to be their statutory or fiduciary duties (having received advice from external financial and legal advisers) determines that the BHP Competing Proposal would, or could reasonably be expected to become, a superior proposal for BHP;
- BHP has provided Woodside with all terms and conditions of the BHP Competing Proposal (including the price and identity of the third party making the competing proposal);
- BHP has given Woodside at least 10 business days after the date on which it provided Woodside with the information on the BHP Competing Proposal to provide a matching or superior proposal; and
- Woodside has not provided a matching or superior proposal by the expiry of the 10 business day period.

If Woodside proposes amendments to the Merger that constitute a matching or superior proposal by the expiry of the 10 business day period and the BHP Board (acting reasonably and in good faith) determines that the Woodside proposal would provide an equivalent or superior outcome for BHP Shareholders as a whole compared with the BHP Competing Proposal, Woodside and BHP must use their best endeavours to agree amendments to the Share Sale Agreement that are reasonably necessary to reflect and implement the revised Woodside proposal as soon as reasonably practicable. BHP must procure that the BHP Board continues to support the Merger (as modified by the Woodside proposal).

BHP does not have a right to match a competing proposal made for the Woodside Group.

Reimbursement fee

Each of Woodside and BHP have agreed to pay a reimbursement fee of US$160 million in certain circumstances.

Woodside must pay the reimbursement fee to BHP if:

- BHP terminates the Share Sale Agreement as a result of a "prescribed occurrence" occurring in relation to Woodside, Woodside breaches a warranty (or a breach of a Woodside warranty would occur at Implementation) and fails to remedy such breach, and the loss reasonably expected to follow from the breach would exceed US$500,000,000, or Woodside materially breaches its obligations under the Share Sale Agreement and fails to remedy such breach;

- half or more of the Woodside Board members change, withdraw or qualify their recommendation that Woodside Shareholders vote in favour of the Merger Resolution, unless the Independent Expert's Report concludes that the Merger is not in the best interests of Woodside Shareholders (except where that conclusion is due to the existence of a Woodside Competing Proposal), or Woodside is otherwise entitled to terminate the Share Sale Agreement before Implementation; or
- a Woodside Competing Proposal is announced before the earlier of the termination of the Share Sale Agreement and 30 June 2022, and within 12 months of the announcement, the third-party proponent of the Woodside Competing Proposal enters into an agreement to complete, or completes, certain types of Woodside Competing Proposal.

BHP must pay the reimbursement fee to Woodside if:

- Woodside terminates the Share Sale Agreement as a result of a "prescribed occurrence" occurring in relation to BHP Petroleum, BHP breaches a warranty (or a breach of a BHP warranty would occur at Implementation) and fails to remedy such breach, and the loss reasonably expected to follow from the breach would exceed US$500,000,000, or BHP materially breaches its obligations under the Share Sale Agreement and fails to remedy such breach;
- BHP terminates the Share Sale Agreement as a result of BHP or the majority of the BHP Board announcing an intention, or BHP entering into an agreement, to pursue a superior proposal in relation to BHP Petroleum in circumstances where Woodside has not made a counterproposal, or Woodside has made a counterproposal and the BHP Board (acting reasonably and in good faith) has determined that the counterproposal would not provide an equivalent or superior outcome for BHP Shareholders;
- BHP is approached during the Exclusivity Period in respect of a BHP Competing Proposal, and within 12 months of the termination of the Share Sale Agreement, the third party proponent of the BHP Competing Proposal enters into an agreement to complete, or completes, the BHP Competing Proposal; or
- during the Exclusivity Period, BHP announces an intention to effect, or completes, a demerger of BHP Petroleum instead of pursuing the Merger.

The reimbursement fee is not payable if the Merger is implemented.

The reimbursement fee is the sole and exclusive remedy available to a party in all circumstances where the Merger is not implemented.

Termination

The Share Sale Agreement contains customary termination rights for either party, including in relation to the failure of a Condition and for material breach.

In addition:

- Woodside has a right to terminate the Share Sale Agreement in the event that there is a reduction of 15% or more of BHP Petroleum's proven and probable reserves (calculated in accordance with the Share Sale Agreement, applying SPE PRMS methodology) from 1010.7 MMboe (subject to certain exclusions).
- BHP has a right to terminate the Share Sale Agreement in the event that a Woodside credit rating on a number of indices is downgraded to Ba1 or BB+ or lower (or a credit rating agency issues an assessment indicating a likely downgrade to those levels after Implementation) or there is a reduction of 158.33 MMboe or more from the Woodside Group's proven and probable reserves (calculated in accordance with the Share Sale Agreement, applying SPE PRMS methodology) of 1055.5 MMboe (subject to certain exclusions).

Termination rights under the Share Sale Agreement are set out in paragraph 7 of Part 10 *(Summary of the Merger)* of this Prospectus.

Costs and expenses

Woodside and BHP have agreed that the costs incurred in connection with the Merger (assuming Implementation) will generally be borne or absorbed by Woodside (either directly or through ownership of BHP Petroleum), other than in respect of the following:

- Costs associated with separating BHP Petroleum from the BHP Group systems, processes and arrangements are to be borne by BHP (without recharge to BHP Petroleum).

- Costs and expenses payable to BHP's advisers in respect of advice on the Merger must be borne by BHP.
- Any direct costs incurred as a result of, or to give effect to, the Restructure of certain entities outside of BHP Petroleum must be borne by BHP.
- As otherwise set out in the Integration and Transition Services Agreement.

Governing laws

The Share Sale Agreement is governed by the laws of Victoria, Australia and Woodside and BHP subject themselves to the exclusive jurisdiction of the courts of Victoria, Australia.

Letter agreement

On 7 April 2022, Woodside and BHP entered into a letter agreement in order to confirm a variety of mechanical matters under the Share Sale Agreement, including in relation to:

- the status of the Conditions and the timing of Implementation, to the effect that unless there is a failure of a Condition, the Share Sale Agreement will be deemed unconditional and Implementation will occur on 1 June 2022; and
- arrangements for Implementation and the distribution of the Share Consideration, including in relation to the definition of Eligible BHP Shareholder and Small Parcel BHP Shareholders.

Part 11 – Overview of the Merged Group

1 Overview of the Assets

On Implementation, the Merged Group will comprise the Woodside Group and BHP Petroleum.

The Merged Group will have a global portfolio of currently producing assets and future growth projects and opportunities. The key producing assets are integrated LNG projects in Western Australia, oil fields in the U.S. GOM as well as oil and gas assets in Australia and T&T. The Merged Group's key growth projects will include the Scarborough and Pluto Train 2 developments in Australia, Shenzi North and Mad Dog Phase 2 additions to the currently producing U.S. GOM oil projects and the greenfield Sangomar Oil Field Development offshore Senegal. The Merged Group will also hold exploration and discovered resource opportunities in Australia, Timor-Leste, Senegal, South Korea, Egypt, Congo, T&T, central and western U.S. GOM, Mexican Gulf of Mexico, Canada, and Barbados.

For a detailed overview of the Merged Group's assets refer to paragraph 4 of Part 7 *(Overview of Woodside)* and paragraph 2 of Part 8 *(Overview of BHP Petroleum)* of this Prospectus.

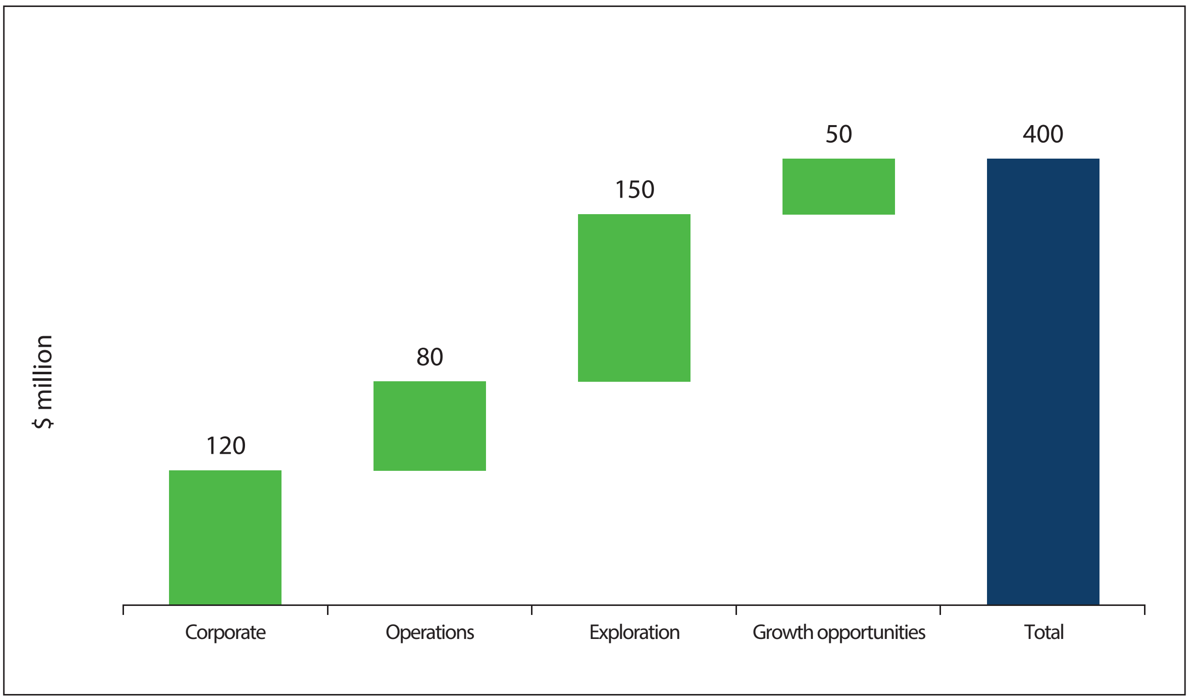
2 Potential synergies and value creation

2.1 Overview

Woodside has undertaken a review of costs for the Merged Group (benchmarked against industry peer performance) and produced a comprehensive list of synergy opportunities. These opportunities are expected to deliver annual savings in excess of US$400 million per annum (pre-tax 100% basis) comprising, approximately US$120 million of corporate savings, US$80 million of cost savings related to operations of the business, US$150 million in exploration expenditure reduction and $50 million of execution costs savings associated with future growth opportunities. These synergies are expected to be realised progressively and to be implemented by early 2024.

The organisation structure and operating model for the Merged Group is being designed and will be progressively implemented. The new operating model will include structural and sustainable changes which will reflect a more cost-efficient operating model and reflect synergies from the combination of the two businesses. The new organisation design will feature a significant reduction in executive level positions, a reduction in management layers and an overall increase in the breadth of each manager's area of responsibility and accountability. In addition to the structural and operating model improvements there will be organisational synergies arising from the removal of duplicative or overlapping staffing levels which exist across corporate areas, support functions, commercial and technical functions, and asset support.

Figure 21 – Approximate Annual Synergies and Value Creation Categories (US$ million real term 2022)



Key areas of the business where these synergies are expected to be achieved are set out in the following sections. As part of the integration process, Woodside is aiming to identify further synergies and value creation opportunities.

2.2 Corporate

This category refers to those costs incurred in supporting the Operations, Exploration, Development and Growth activities of the Merged Group.

In addition to the savings to be derived from the improvements in organisation structure and operating model referred to above, Woodside also expects to be able to reduce costs by consolidating third party spend, by removing processes across corporate functions and overlapping assets and rationalising information technology applications, licences and subscriptions.

Examples are outlined below:

- Implementing a consolidated Enterprise Resource Planning System to enable integrated cost reporting and control and reducing the ongoing cost of maintaining duplicate systems.
- Combining or rationalising legal entities.
- Consolidating corporate consultant costs.
- Consolidating and renegotiating enterprise-wide arrangements with key vendors for software and services.
- Consolidation of Marketing information systems and data providers.
- Rationalising licences and subscriptions for various marketing services.
- Consolidation of teams and office space to reduce property costs.

The synergies under this category account for ~30% of the overall synergies estimate of ~US$400 million.

2.3 Operations

Prior to Implementation, Woodside and BHP Petroleum have separately commenced programmes to improve operational efficiency and reduce costs across their assets. Following Implementation, the Merged Group will continue this work and will further consolidate operations and execute efficient practices across the portfolio which is intended to deliver further cost reductions.

Examples are outlined below:

Operating and Maintenance cost:

- Leveraging systems and digital solutions to reduce operating and maintenance costs across all assets for sustained cost reduction.
- Sequencing maintenance programmes across certain assets to optimise workforce access to reduce cost and execution risk.
- Digitising maintenance strategies across all assets to reduce spend on planning, logistics and materials.
- Reducing the cost of production maintenance through volume consolidation of Maintenance Repairs and Operations, chemicals, and other goods to be implemented across the assets progressively.

Supply Chain and Procurement:

- Leveraging long-term relationships with key contractors and improved purchasing power due to economies of scale to secure better service and pricing.
- Unifying and streamlining inventory management systems.
- Consolidating the Australian logistics and material network; especially ground, air and vessel transportation support for Western Australian assets.
- Consolidating supply base operations.

Asset productivity:

- the Merged Group will also seek to improve the production performance of its upstream assets, sharing experience and technology solutions to improve uptime and lower unit-production costs.

The synergies under this category account for ~20% of the overall synergies estimate of ~US$400 million.

2.4 Exploration

Woodside has identified opportunities to reduce exploration expenditure. This saving will be achieved by reducing headcount across the function and technical support functions, high-grading the combined exploration portfolio and focusing on progressing high-quality prospects that have a clear path to commercialisation.

Opportunities have also been identified to make the delivery of exploration services more efficient including:

- Rationalising licences, data subscriptions and applications; and
- Consolidation of seismic campaigns.

The synergies under this category account for ~40% of the overall synergies estimate of ~US$400 million.

2.5 Growth Opportunities

The combined portfolio will allow the Merged Group to high-grade investment opportunities and improve phasing of the enlarged opportunity set. Opportunities have also been identified which have the potential to reduce execution costs. Examples are outlined below:

- Inventory optimisation by region and for Exploration, Decommissioning and Development programmes.
- Sharing global inventory and regional backup.
- Standardise casing, wellheads and trees and work with suppliers to maintain sufficient inventory to purchase on consignment.
- Consolidate rig schedules to provide larger work scope, longer contracts and increased learning curve efficiencies.
- Scale up purchasing power with major vendors engaged to deliver key projects.

The synergies under this category account for ~10% of the overall synergies estimate of ~US$400 million.

2.6 Marketing

The Merged Group's increased scale and existing LNG shipping capability will help to improve shipping utilisation and reduce transportation and delivery unit costs. Woodside will determine the magnitude of this synergy post Implementation.

2.7 Cost of attainment of synergies

Woodside estimates that the implementation of the potential synergies would give rise to one-off costs of approximately US$500 – 600 million, anticipated to be incurred in the first two years following Implementation. This estimate includes provisions for digital integration, severance costs, consultant and team costs necessary to complete the synergy attainment work. This estimate excludes costs to implement the marketing synergies, which will be determined post Implementation.

3 Summary of the Merged Group reserves and resources determined by the Competent Person

The Merged Group's Net Reserves as at 31 December 2021

Country	Asset	Oil and Condensate Reserves (MMbbl)		Gas Reserves (Bcf)	
		1P	2P	1P	2P
Australia	Greater Pluto	19.5	24.3	1,575.3	1,951.2
	Bass Strait	10.6	17.9	490.0	829.8
	NWS	43.2	55.6	1,439.5	1,892.4
	Greater Enfield	16.0	24.1	0.0	0.0
	Pyrenees	10.0	19.0	0.0	0.0
	Macedon	0.0	0.0	239.0	308.4
	Wheatstone	8.8	16.5	608.9	947.4
	Scarborough	0.0	0.0	7,212.9	11,242.2
US Gulf of Mexico	Shenzi	64.0	91.9	33.5	51.2
	Shenzi North	16.4	26.8	11.6	18.9
	Atlantis	59.4	153.9	55.6	117.0
	Mad Dog	129.2	180.0	40.1	55.9
Trinidad & Tobago	Angostura	1.6	1.9	167.9	230.1
	Ruby	1.4	1.8	24.0	33.2
Senegal	Sangomar	100.6	148.1	0.0	0.0
	Total	**480.8**	**761.7**	**11,898.5**	**17,677.9**

Notes:

1. Net Reserves are Company's net economic entitlement volume after deduction of royalties or according to the terms of PSC governing the asset
2. Net gas reserves include NGL volumes and 1,268 Bcf (1P)/1,859 Bcf (2P) consumed in operations (CiO or fuel); the Competent Person's Report presents CiO volumes, company net NGL reserves and company net gas reserves excluding fuel in separate tables. BHP Petroleum includes onshore and offshore fuel used in operations as reserves whilst Woodside includes downstream fuel as reserves
3. Sangomar Reserves include production through to the end of the relevant concessions only.
4. Totals may not exactly equal the sum of the individual entries because of rounding.

The Merged Group's Net Contingent Resources as at 31 December 2021

Country	Asset	Net 2C Contingent Resources	
		Oil and Condensate (MMbbl)	Gas (Bcf)
Australia	Greater Pluto	22.8	1,290
	Bass Strait	18.1	138
	NWS	35.7	582
	Greater Enfield	34.4	351
	Pyrenees	16.4	0
	Macedon	0.0	107
	Wheatstone	0.2	15
	Greater Scarborough	0.0	1,318
	Greater Browse	119.3	4,469
	Greater Sunrise	75.6	1,717
U.S. GOM	Shenzi	25.0	7
	Wildling	36.9	11
	Atlantis	88.3	38
	Mad Dog	70.2	4
Myanmar	Myanmar A6	0.0	567
Mexico	Trion	282.6	210
Trinidad & Tobago	Angostura	1.3	219
	Calypso	4.9	2,877
	Magellan	0.0	313
Senegal	Greater Sangomar	317.1	301
Canada	Liard	0.0	13,350
	Total	**1,148.8**	**27,884**

Notes:

1. Net Contingent Resources in this table are the Merged Group's working interest fraction of the gross field Contingent Resources; they do not represent the Merged Group's actual net entitlement under the terms of the contracts that govern the asset, which would be lower for PSCs or where royalty is deductible.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the asset may not be developed in the form envisaged or may not be developed at all (i.e. no "Chance of Development" (Pd) factor has been applied).
3. Contingent resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. Contingent gas resources include NGL volumes.
5. Totals may not exactly equal the sum of the individual entries because of rounding.
6. No deduction has been made for fuel, flare and shrinkage.
7. The Competent Person's Contingent Resource volume for Liard (Canada) shown is based on a working interest of 50.0% on the basis that not all the infrastructure-free leases have been transferred. Woodside applies a working interest of 94.9% based on full equity in 28 non infrastructure related Liard Basin leases from Chevron Canada

4 Group structure

The subsidiaries of the Merged Group will comprise all of the subsidiaries of Woodside set out in paragraph 13 of Part 7 (*Overview of Woodside*) along with all of the subsidiaries of BHP Petroleum set out in paragraph 6 of Part 8 (*Overview of BHP Petroleum*). The list of subsidiaries contains all group members with the exception of certain entities in which Woodside will hold, an insignificant minority shareholding.

5 Employees

As at the Implementation Date, it is expected that the Merged Group will have approximately 4,745 full-time employees, the majority of whom are located in Australia and the United States of America. This is derived from 3,729 employees from Woodside Group at the Last Practicable Date and 1016 employees from BHP Petroleum at 31 December 2021.

5.1 Woodside Employees

As at the Last Practicable Date the Woodside Group had 3,729 full-time employees, 3,610 of whom are located in Australia.

For the Historical Financial Information Period, Woodside has employed the numbers of people as detailed in the table below as at 31 December.

Employees for the Historical Financial Information Period

PEOPLE	2021	2020	2019
Employment region (number of staff by region)			
Australia	3,660	3,705	3,874
Africa/Middle East	35	9	8
Asia	48	49	23
Europe	8	7	42
USA and Canada	13	7	15
Total number of employees	**3,764**	**3,777**	**3,962**
Total number of contractors	**267**	**235**	**337**

5.2 BHP Petroleum Employees

BHP Petroleum's average number of employees and contractors for the year ended 31 December 2021 was 1,367. On average, approximately 75% of the workforce were employees (1,016) and approximately 25% were contractors (351). There has not been any material change in the number of employees or contractors since 31 December 2021.

Average number[48] of BHP Petroleum employees for 2021, 2020 and 2019 by geographical area

PEOPLE	2021	2020	2019
Employment region (number of staff by region)			
Australia	135	177	178
United States	719	1,031	1,103
Rest of World	162	182	201
Total	**1,016**	**1,390**	**1,482**

[48] Average employee numbers include 100 per cent of employees of subsidiary companies. Employees of equity accounted investments and joint operations are not included. Part-time employees are included on a full-time equivalent basis. Employees of businesses disposed of during the year are included for the period of ownership. Contractors are not included.

In addition, as a subsidiary of BHP, BHP Petroleum has also historically benefited from corporate and centralised administration services provided by employees within the BHP group's corporate divisions. These groups are in addition to the employee numbers above and services typically include administration support activities in Human Resources, Procurement, Marketing and Finance.

6 Intentions of the Merged Group

6.1 Integration planning and business continuity

Woodside and BHP have established a joint integration team that has commenced integration planning activities across key business areas.

The joint integration team is led by a senior executive representative from each of Woodside and BHP.

The objectives of this joint integration team are to:

- develop a detailed integration plan which identifies activities necessary to bring together the operation of the BHP Petroleum business and Woodside business on and from Implementation;
- identify the short-term transition services that will be required immediately after Implementation; and
- combine the respective oil and gas businesses of Woodside and BHP while minimising disruption to the business of the Merged Group.

The final integration plan will set out the key activities to achieve integration of the Woodside Group and BHP Petroleum (including organisational design, regulatory management, stakeholder engagement, and systems and operations transfer).

Following Implementation, the joint integration team will endeavour to ensure that the identified synergies of the Merger are actioned, monitored and realised as planned.

The Woodside Board is confident that separation of BHP Petroleum from BHP and the subsequent integration of the Woodside Group and BHP Petroleum can be achieved with minimal impact in conducting the Merged Group business safely and efficiently.

6.2 Values

The Merged Group values are still being defined but will reflect Woodside's fundamental values, which are as follows:

- **Respect** – we give everyone a fair go, give and receive feedback and listen with empathy;
- **Ownership** – we set goals, hold ourselves accountable and learn, including from mistakes;
- **Sustainability** – we keep each other safe, look after the environment and support our community;
- **Working Together** – we embrace inclusion, value diversity and build long-term relationships;
- **Integrity** – we are transparent, honest and fair and build trust by doing the right thing; and
- **Courage** – we speak up, act decisively and embrace change.

6.3 Strategy

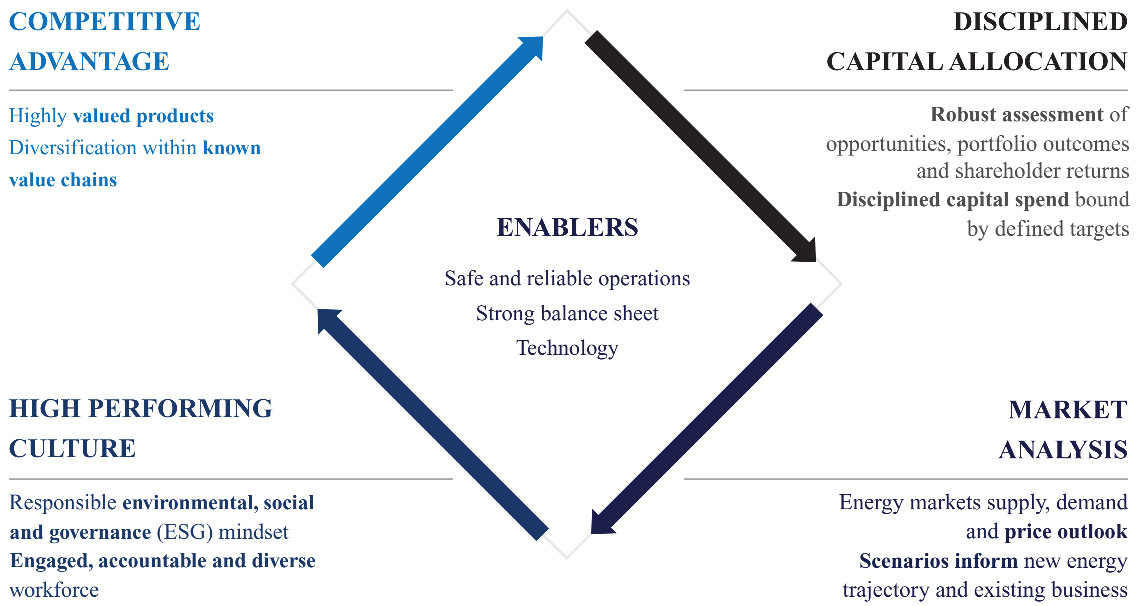
Woodside will develop a strategy for the Merged Group to optimise value and shareholder returns through the energy transition. The goal is to leverage its base business profitability to build a low-cost, lower carbon, profitable, financially resilient and diversified portfolio of growth opportunities to achieve its strategic objectives.

The strategy will see Woodside continuing to develop hydrocarbons while gradually building optionality in new energy products and lower-carbon services such as ammonia, liquid hydrogen and development of carbon capture and utilisation through targeted opportunities with prospective attractive growth.

In addition to these new energy opportunities, Woodside is assessing opportunities for carbon capture and storage, including assessing an opportunity to develop a large-scale, multi-user project near Karratha, Western Australia.

The strategic planning framework will facilitate delivery of Woodside's strategy and execution of future investment decisions.

Figure 22



Competitive advantage

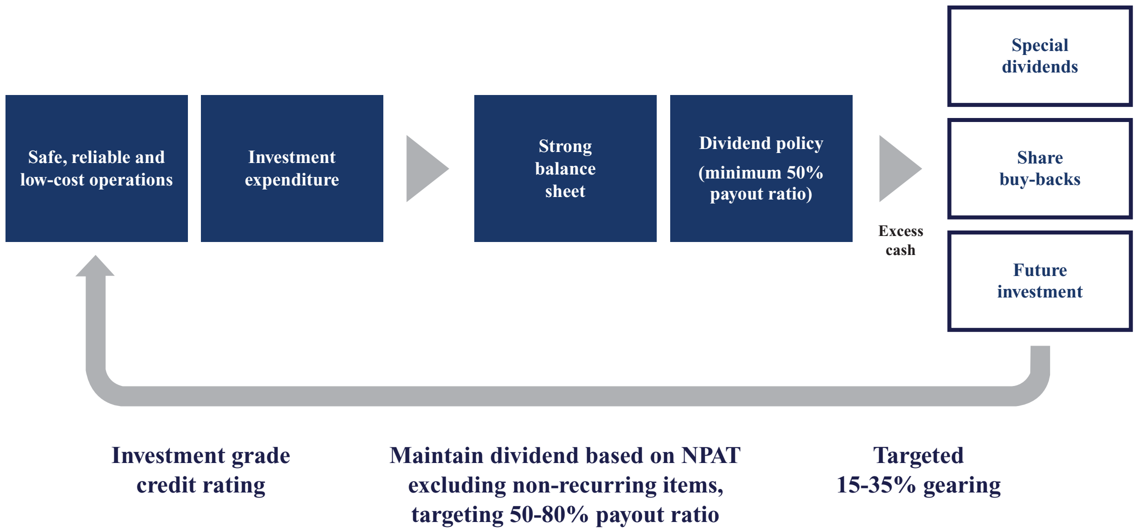
Woodside's strategy aims to establish a competitive advantage by offering to its customers high valued products. Woodside operates international assets to deliver low-cost and high margin products, and is maturing a portfolio of high-quality growth options, including both hydrocarbon and new energy opportunities. Understanding the changes in the energy market, combined with diversifying the portfolio into new energy, will help Woodside to identify new areas within known segments of the energy value chain where the Merged Group may gain a competitive advantage.

Woodside's strategy to diversify its portfolio into new energy will be built on Woodside's understanding of the energy value chain and the market evolution, and its capabilities to identify areas of the energy value chain where it may gain a competitive advantage.

Disciplined capital management and allocation

Woodside's approach to capital management is to deploy its capital within a framework designed to optimise shareholder returns, through investing in growth opportunities or distributions, whilst maintaining a strong balance sheet.

Figure 23



Woodside has a portfolio of international assets providing safe, reliable and low-cost operations, which provides the foundation to deliver new growth opportunities. In respect of investing in growth opportunities, Woodside's disciplined capital allocation approach includes robust assessment of opportunities, portfolio outcomes and shareholder returns, while maintaining focus on safe and reliable operations.

Woodside's capital allocation approach aligns to its strategy and is expected to enable the current portfolio to evolve into an optimized portfolio for the future, incorporating a mix of oil, gas, and new energy opportunities and shareholder returns.

The Merged Group will adopt Woodside's capital allocation approach.

Woodside's capital allocation framework sets target investment criteria for the assessment of oil, gas and new energy opportunities. It comprises investment targets for different business segments, as well as portfolio level financial and non-financial metrics to evaluate opportunities for their strategic fit and performance under different scenarios. The capital allocation framework is used to create a diversified and flexible portfolio which is responsive to changes in demand and supply for Woodside's products.

Figure 24: Capital allocation framework

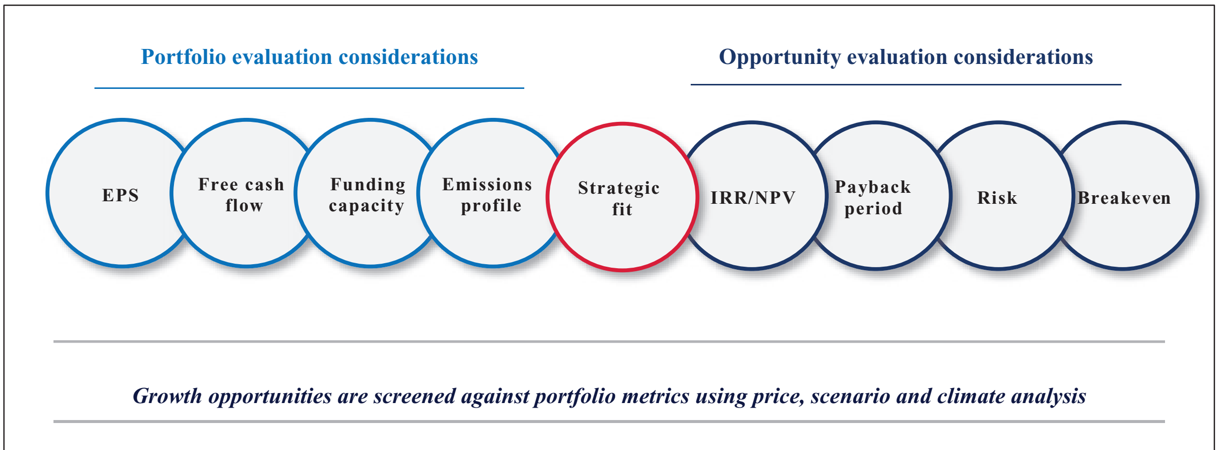
	OIL	GAS		NEW ENERGY
	OFFSHORE	PIPELINE	LNG	DIVERSIFIED
FOCUS	Generate high returns to fund diversified growth, focusing on high quality resources	Leveraging infrastructure to monetise undeveloped gas, including optionality for hydrogen		New energy products and lower carbon services to reduce customers' emissions; hydrogen, ammonia, CCUS
CURRENT CHARACTERISTICS	High cash generation Shorter payback period Quick to market	Stable long-term cash flow profile Resilient to commodity pricing	Long-term cash flow Strong forecast demand Upside potential	Developing market Lower capital requirement Lower risk profile
OPPORTUNITY TARGETS	IRR > 15% Payback within 5 years[1]	IRR > 12% Payback within 7 years[1]		IRR > 10% Payback within 10 years[1]
EMISSIONS REDUCTIONS	30% net emissions reduction by 2030, net zero aspiration by 2050 or sooner[2]			

CCUS refers to carbon capture utilisation and storage.

1. Payback refers to RFSU + X years.
2. Target is for net equity Scope 1 and 2 greenhouse gas emissions, relative to a starting base of the gross annual average equity Scope 1 and 2 greenhouse gas emissions over 2016-2020 and may be adjusted (up or down) for potential equity changes in producing or sanctioned assets with an FID prior to 2021. Following Implementation (which remains subject to Conditions including regulatory approvals), the starting base will be adjusted for the then combined Woodside and BHP petroleum portfolio.

When assessing opportunities, Woodside considers a broad range of portfolio evaluation and opportunity evaluation factors relevant to the opportunity. These assessments can apply to acquisitions or divestments, and for evaluating the impact of a new project on the portfolio.

Figure 25: Portfolio and opportunity evaluation considerations[45]



45 Illustrative of the considerations. Not an exhaustive list.

The Merged Group portfolio will provide optionality across oil, gas and new energy. Each business segment is expected to meet specific investment criteria that reflect different risk-reward profiles.

The allocation approach intends to support continued investment in hydrocarbons where screening criteria are met as well as building capability and competitive advantage in new energy. In addition, Woodside expects to manage the emissions from all these investments to meet Woodside's net equity Scope 1 and Scope 2 greenhouse gas emission reduction target of 15% by 2025, 30% by 2030, and a net zero aspiration by 2050 or sooner.[46]

Capital investment requirements are primarily funded by Woodside's resilient and stable operating cash flows, in conjunction with a number of capital management levers:

- Participating interest management, ensuring a balance of capital investment requirements, project execution risk and long-term value; In January 2022 Woodside completed the selldown of a 49% non-operating participating interest in the Pluto Train 2 Joint Venture. In 2022, Woodside will continue the targeted sell-down processes for Sangomar and the Scarborough offshore resource;
- Debt management, to ensure that Woodside continues to have access to premium debt markets at a competitive cost to support its growth activities. Woodside seeks to manage average debt maturity on its debt portfolio. Woodside's gearing target is 15-35%. Woodside continues to target maintaining an investment-grade credit rating; and
- Focused expenditure management, to ensure prudent and efficient deployment of capital to support delivery of base business and growth opportunities.

Oil

The Merged Group's oil investments will focus on high quality oil resources that can generate high returns to fund its future diversified growth. These opportunities are characterised by quick developments, short payback periods and significant cash generation once operational. Subsea tiebacks to existing oil infrastructure can be particularly attractive.

Woodside plans to target oil opportunities for the Merged Group that deliver rates of return greater than 15% and payback within the first 5 years from RFSU.

Gas

Woodside believes gas will continue to play a major role in the energy system, as countries switch from coal and look for stable forms of base-load power to support renewable energy generation. The Merged Group will invest in LNG and pipeline gas opportunities, focusing on developments through existing infrastructure and opportunities to develop optionality for hydrogen.

Woodside plans to target gas opportunities for the Merged Group that deliver rates of return above 12% and payback within 7 years from RFSU.

New Energy

Woodside believes the new energy products and services market is developing and could grow quickly as countries and businesses commit to net zero goals and policies to incentivise lower carbon solutions across the globe strengthen. Woodside has set a target to invest at least US$5 billion on new energy products and lower carbon services by 2030 to meet this growing demand.[47]

Woodside expects to diversify its product stream by investing in a diversified range of new energy opportunities. These include products and services to reduce customers' emissions such as the supply of hydrogen and ammonia, and the provision of Carbon Capture, Utilisation and Storage services to third-parties to support their decarbonisation efforts.

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[46] Target is for net equity Scope 1 and 2 greenhouse gas emissions, relative to a starting base of the gross annual average equity Scope 1 and 2 greenhouse gas emissions over 2016-2020 and may be adjusted (up or down) for potential equity changes in producing or sanctioned assets with an FID prior to 2021. Following Implementation (which remains subject to Conditions including regulatory approvals), the starting base will be adjusted for the then combined Woodside and BHP petroleum portfolio.

[47] Investment target assumes completion of the Merger. Individual investment decisions are subject to Woodside's investment hurdles. Not guidance.

These opportunities are expected to be scalable in nature, providing the opportunity for staged investment as the market develops.

Opportunities that deliver rates of return greater than 10% and payback within 10 years from RFSU will be targeted for the Merged Group. These thresholds reflect that these projects are not exposed to upstream or resource risk in the way a traditional oil or gas development is.

New energy opportunities recently announced by Woodside include H2Perth (an ammonia and hydrogen opportunity located near the Kwinana industrial hub south of Perth, Western Australia), H2TAS (a renewable hydrogen and ammonia opportunity located in the Bell Bay area of northern Tasmania), H2OK (a liquid hydrogen opportunity in Oklahoma) as well as a collaboration with Heliogen on deployment of their concentrated solar technology at a pilot facility in California.

Market analysis

Woodside's investment decisions are informed by energy market analysis including supply, demand and price outlooks. Through market analysis, Woodside seeks to monitor the global macroeconomic and geopolitical environment and the energy markets outlook to determine how these factors can impact the organisation and how to best respond, including how Woodside allocates capital. This is expected to include third-party scenarios and Woodside's own assessment of product prices and market conditions.

Woodside uses scenario models to test the resilience of the current portfolio to different energy outlooks. The robustness of potential investments are also assessed to inform decisions around the growth strategy and future portfolio of the Merged Group to ensure that Woodside will remain profitable and resilient through various commodity cycles and climate outcomes, including the energy transition trajectory.

High performing culture

Woodside's high performing culture, which includes an engaged, accountable and diverse workforce with a responsible environmental, social and governance (ESG) mindset, is critical to ensuring Woodside's effectiveness in delivering its vision and strategy.

Enablers

Woodside's ability to successfully navigate the energy transition will be underpinned by three primary enablers. Woodside's safe and reliable operations will aim to keep its people safe and protect its revenues. Woodside's focus on maintaining a strong balance sheet will aim to provide the financial flexibility to support the maturation of growth opportunities. Woodside's technology capability will aim to improve base business efficiency and productivity and will enable expansion into new markets for the Merged Group.

7 Merged Group capital structure

The table below summarises the Woodside Shares that are expected to be in issue for the Merged Group on Implementation:

Timing	Number
In issue as at the Last Practicable Date	983,980,823
Estimated to be issued under the Merger	914,768,948[48]
Estimated total in issue following Implementation	1,898,749,771[49]

[48] Based on number of Woodside Shares in issue as at the Last Practicable Date and assumes no additional Woodside Shares are issued between the Last Practicable Date and Implementation.

[49] Assumes no additional Woodside Shares are issued between the Last Practicable Date and Implementation.

The table below summarises the Woodside unquoted equity securities that are expected to be in issue on Implementation[50]:

Unquoted equity securities	Number
Equity Rights	5,711,407
Performance Rights	1,439,717
Variable Pay Rights	338,261

Unquoted equity securities are awarded under the Woodside Equity Plan, Supplementary Woodside Equity Plan, Executive Incentive Plan and Executive Incentive Scheme. Paragraph 14 of Part 21 *(Additional Information)* of this Prospectus summarises Woodside's employee equity incentive plans. Further details of the unquoted equity securities including vesting dates are available in the remuneration report in Woodside's Annual Report 2021 on pages 69-92.

On Implementation, it is expected that BHP Shareholders will own approximately 48% of the Merged Group (subject to adjustment in certain circumstances and subject to any BHP Shareholders being Ineligible Foreign BHP Shareholders or Relevant Small Parcel BHP Shareholders). The Merged Group's financing arrangements including its banking facilities, access to capital market and maintenance of a relationship banking panel will remain in line with Woodside Financing Arrangement as set out in Annexure 1 of Part 24 *(Woodside Historical Financial Information)* and Part 17 *(Operating and Financial Review of Woodside*) of this Prospectus. Specifically, commodity price risk management will be undertaken in line with approved Woodside Board mandate parameters.

See paragraph 11 of Part 21 *(Additional Information)* of this Prospectus for more information in relation to the interests that Woodside Directors and other Key Management Personnel hold in Woodside Shares.

8 Hedging

The Merged Group's approach to financial risk management will remain consistent with the Woodside hedging principles, as set out in paragraph 25 of Part 7 *(Overview of Woodside)* of this Prospectus.,

Specifically, commodity price, interest rate and foreign exchange risk management will be undertaken in line with approved board mandate parameters.

9 Dividend policy

The Merged Group's dividend policy is expected to be unchanged compared to Woodside's current dividend policy. Please refer to paragraph 25 of Part 7 *(Overview of Woodside)* of this Prospectus for more details.

10 Corporate governance

The corporate governance principles of the Merged Group are expected to be the same as the Woodside governance. Please refer to paragraph 2 of Part 12 *(Directors, Senior Executives and Corporate Governance)* of this Prospectus for more details.

11 Corporate office, trading name and listing venues

It is intended that after Implementation the head office will remain in Western Australia at Mia Yellagonga, 11 Mount Street, Perth, WA 6000, Australia.

The trading name of the Merged Group will be Woodside Energy Group Ltd.[51]

Woodside securities have a primary listing on the ASX and Woodside has made applications for a secondary listing on the LSE and NYSE.

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50 Based on number of unquoted equity securities as at Last Practicable Date and assumes no additional unquoted equity securities are issued between the Last Practicable Date and Implementation.

51 Subject to approval by the Woodside Shareholders at the Woodside Shareholders' Meeting.

12 Decommissioning

Cost estimates and scope of work

Woodside overview

Decommissioning the site of oil and gas field developments, processing plants and associated infrastructure is a well established requirement of the oil and gas lifecycle following cessation of production.

Woodside estimates the future remediation and removal costs of offshore oil and gas platforms, production facilities, wells and pipelines at different stages of the development and construction of assets or facilities. In many instances, remediation and removal of assets occurs many years into the future.

Woodside's decommissioning and restoration cost estimates are based on compliance with the requirements of relevant regulations which vary for different jurisdictions and are often non-prescriptive. Australian legislation, for example, requires removal of structures, equipment and property, or alternative arrangements to removal which are satisfactory to the regulator. Woodside maintains technical expertise to ensure that industry learnings, scientific research and local and international guidelines are reviewed in assessing its decommissioning and restoration obligations.

The decommissioning and restoration cost estimates requires judgemental assumptions regarding removal date, environmental legislation and regulations, the extent of restoration activities required, the engineering methodology for estimating cost and future removal technologies in determining the removal cost.

Woodside's estimates include the following costs:

- for onshore assets, costs associated with the removal of production facilities and aboveground pipelines to allow site reuse. Provision is made for groundwater monitoring and remediation.
- for offshore assets, costs associated with the plugging and abandonment of wells and the removal of offshore platform topsides, floating production storage offloading (FPSO) and some subsea infrastructure. It is currently Woodside's assumption that certain pipelines and infrastructure, parts of offshore platform substructures, and certain subsea infrastructure will remain in-situ where it can be demonstrated that this will deliver equal or better health, safety and environmental outcomes than full removal and that regulatory approval is obtained where the arrangements are satisfactory to the regulator.

The basis of the cost estimate for assets with approved decommissioning plans or directions issued by a regulator can differ from the estimate that would be produced from the application of the assumptions above. Whilst the costs are based on current knowledge and information, further studies and detailed analysis of the restoration activities for individual assets will be performed near the end of their operational life and/or when detailed decommissioning plans are required to be submitted to the relevant regulatory authorities.

BHP overview

Woodside has assessed that BHP adopts a similar approach in estimating the scope, costs and timing of decommissioning and restoration activities.

Indicative Merged Group Decommissioning Costs

Figure 26 below is an indicative profile for decommissioning costs of the Merged Group and is calculated on the following basis:

- the assumptions stated above in relation to the full or partial removal of assets;
- Woodside costs and schedule have been applied to Woodside assets installed as at 31 December 2021; and
- BHP Petroleum costs and schedule have been applied to BHP Petroleum assets installed as at 30 June 2021.

Yet to be installed parts of sanctioned development projects including Scarborough, Pluto Train 2, Sangomar Phase 1, Mad Dog Phase 2, Shenzi North and GWF3/LD are not included in the indicative profile. Current estimates indicate that decommissioning of Sangomar Phase 1 (without further development), US GoM hubs and Scarborough and Pluto LNG will occur post 2040.[52]

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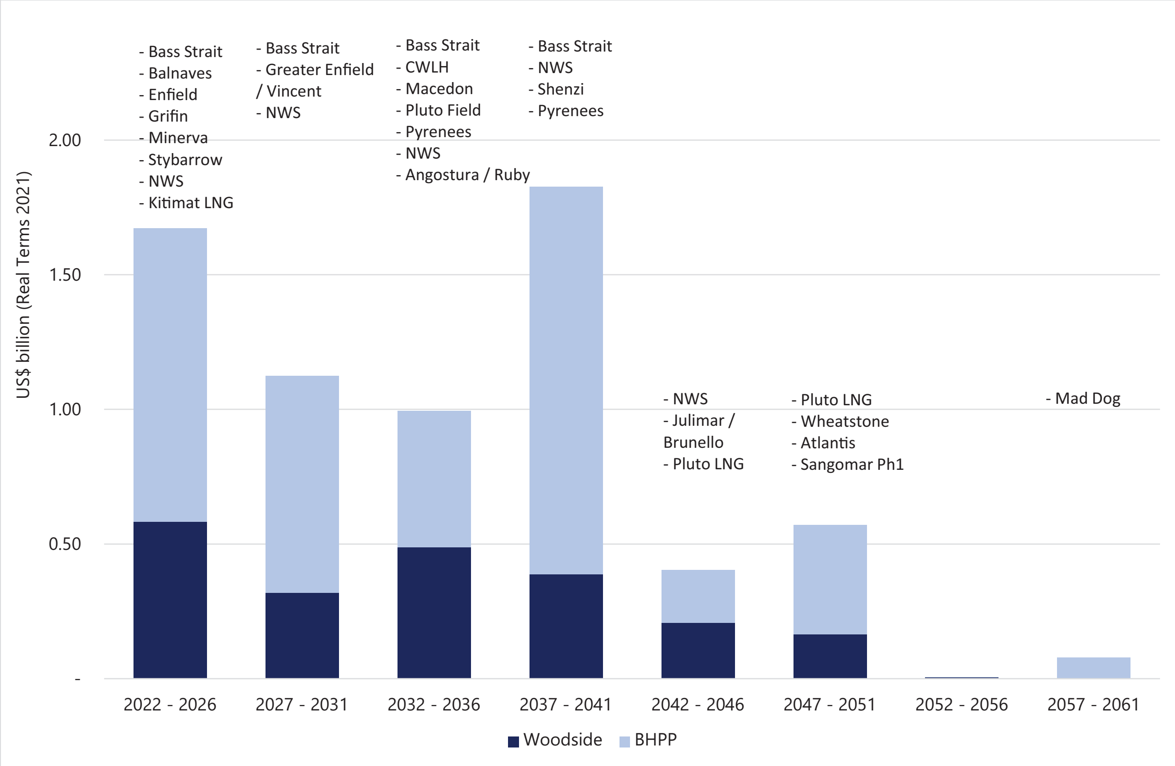
[52] This Figure 26 is indicative only, and is intended to provide an overall future decommissioning costs profile for the Merged Group. It is based on the assumptions outlined above. This Figure 26 is being provided in advance of Implementation of the Merger and based, in some respects, on external views of the BHP Petroleum assets. Accordingly, Figure 26 is provided for illustrative purposes only and should not be relied on as definitive guidance of future decommissioning costs of the Merged Group. Please refer to Part 3 *(Presentation of Financial and Other Information)* of this Prospectus for cautionary information.
Real term costs refer to costs that are not escalated for inflation.

Figure 26: Indicative decommissioning costs (pre-tax) of the Merged Group over 5-year periods (real terms 2021)



Near Term Activities (2022-2026)

The combined portfolio has near term (2022-2026) decommissioning expenditure relating to:

- Assets which have ceased production:
    - Balnaves, Enfield, Griffin and Stybarrow oil fields in north-west Australia;
    - Minerva in Victoria;
    - Parts of the North West Shelf Project; and
    - Parts of the Bass Strait production system.
- Sites related to the exit from Kitimat LNG in Canada
- Exploration and appraisal wells; and
- Production wells in the U.S. GOM which are expected to cease production in this period.

Examples of some of the near-term activities are outlined below:

- **Balnaves, Enfield, Griffin and Stybarrow**: The floating production, storage and offloading (FPSO) facilities associated with each of these oil fields have already been removed. The remaining decommissioning activities relate to the plugging and abandonment of wells and the removal/insitu decommissioning of the flowlines, mooring systems and foundations as well as the Griffin concrete coated steel gas export pipeline.
- **Minerva**: The remaining decommissioning activities relate to removal/insitu decommissioning of the sub-sea pipeline system to shore and the plugging and abandonment of wells.
- **Parts of the North West Shelf Project**: The Echo Yodel and Angel fields have ceased production. The wells associated with the Echo Yodel field were plugged and abandoned in 2021 and the wellheads and pipeline including its plastic coating is planned for removal. The wells associated with the Angel field are also planned to be plugged and abandoned with two subsea Perseus wells which have also ceased production.
- **Parts of the Bass Strait Development:** Certain subsea and platform production wells have already been plugged and abandoned and certain subsea equipment already removed. A number of fields have

now ceased production and an active programme of plugging and abandonment and care and preservation of facilities to allow future removal is ongoing.

Longer Term Activities (beyond 2026)

The timing for longer term decommissioning expenditure (beyond 2026) relating to other assets within the combined portfolio is subject to various factors including, but not limited to:

- field performance;
- commodity price;
- field and infrastructure life extension programmes;
- regulatory requirements; and
- timing of development of additional assets which enables the life of existing assets/infrastructure to be prolonged.

Figure 26 indicates the current outlook when the decommissioning expenditure of the production hubs is forecast without subsequent additional development.

Bass Strait

As set out in Figure 26 above, of the indicative decommissioning costs (pre-tax) of the Merged Group, costs associated with the Bass Strait production system accounts for approximately 40% for the near term (2022-2026) and approximately 25% for the longer term (from 2027 onwards).

Decommissioning activities are being undertaken by Esso Australia Resources, as Operator of the project. The Bass Strait Environmental Plan (dated 26 March 2021) provides an indicative programme of offshore decommissioning activities including equipment which is judged to be removed, equipment which is judged to remain in-situ together with the timing for the proposed decommissioning campaigns. The scope of the equipment which will remain in-situ remains subject to technical investigations and regulator approvals. The BHP indicative costs set out in Figure 26 align with these judgements.

Restoration obligation

From a reporting perspective, Woodside and BHP actively manage their restoration provisions for these future activities which are included in their respective periodic financial statements.

To establish the value of the accounting provision for the Merged Group, in respect of the BHP assets, Woodside has:

- adopted BHP's real term costs[53] and schedule; and
- applied Woodside's escalation and discount rate assumptions[54].

Normalisation of scope and cost estimate methodologies across the Merged Group will be made in subsequent years.

For further detail see the restoration provision on the Proforma Balance Sheet at Part 15 (*Unaudited Pro-Forma Financial Information*) of this prospectus.

The calculation of restoration provisions is conducted by specialist engineers and requires judgemental assumptions to be made regarding removal date, compliance with environmental legislation and regulations, the extent of restoration activities required (including assets remaining in-situ), the engineering methodology for estimating cost, future removal technologies in determining the removal cost, and liability-specific discount rates to determine the present value of these cash flows. Approval by NOPSEMA, the relevant Australian regulator, for items remaining in-situ will only be provided towards the end of field life and accordingly, at 31 December 2021, there is uncertainty whether NOPSEMA or regulators in other jurisdictions will approve plans for these items to be decommissioned in-situ. These assumptions and estimates are inherently subjective and changes can lead to significant differences in the restoration provision.

53 Real term costs refer to costs that are not escalated for inflation.

54 Differences in escalation and discount rate assumptions can have a material impact on the accounting provision.

Part 12 – Directors, Senior Executives and Corporate Governance

1 Directors and Senior Executive

The table below outlines the expected composition of each of the Woodside Board and leadership team upon Implementation. It includes a brief biography for each individual, including details of his or her proposed functions within the Merged Group and details of the names of companies and partnerships (excluding directorships in the Woodside Group or the BHP Group) of which the individual is or has been a member of the administrative, management or supervisory bodies or partners at any time in the five years preceding the date of this Prospectus.

The Woodside Board intend to appoint a current BHP director as a Woodside director following Implementation, although as at the date of this Prospectus no decisions have been made regarding such appointment.

Executive Director	
Name	**Position and Profile**
Meg O'Neill	*BSc (Ocean Engineering), BSc (Chemical Engineering), MSc (Ocean Systems Management)* **Chief Executive Officer and Managing Director** **Term of office:** Director since August 2021 **Independent:** No **Joined Woodside**: 2018 **Experience:** Meg was appointed as Chief Executive Officer and Managing Director on 17 August 2021. Meg joined Woodside as Chief Operations Officer in May 2018. Meg served as Chief Operations Officer until October 2019, as Executive Vice President Development from October 2019 to August 2021, as Executive Vice President Development and Marketing from August 2020 to April 2021 and as acting Chief Executive Officer from April 2021 to August 2021. Prior to joining Woodside, Meg spent 23 years with ExxonMobil in a variety of technical, operational and leadership roles including senior positions such as Vice President Development Africa, Executive Advisor to the Chairman, Vice President Production Asia / Pacific, and country leadership positions in Canada and Norway. **Committee membership**: Nil. **Current directorships/partnerships:** **Vice Chair:** Australian Petroleum Production & Exploration Association (APPEA). **Director:** Reconciliation WA, WA Venues & Events Pty Ltd (WAVE), West Australian Symphony Orchestra (WASO). **Vice President:** Australian Resources and Energy Group (AMMA). **Member:** Chief Executive Women, UWA Business School Advisory Board. **Directorships/partnerships/other interests within the past five years:** GLX Holdings Limited (2020 to 2021) and North West Shelf Shipping Service Company Pty Ltd (2020 to 2021).

Non-Executive Directors	
Name	**Position and Profile**
Richard Goyder, AO	*BCom, FAICD* **Chair**: Chair since April 2018 **Term of office**: Director since August 2017 **Independent**: Yes **Experience**: Richard spent 24 years with Wesfarmers Limited, where he served as Managing Director and CEO from 2005 to late 2017. Richard served as chair of the Australian B20 (the key business advisory body to the international economic forum which includes business leaders from all G20 economies) from February 2013 to December 2014. **Committee membership**: Chair of the Nominations & Governance Committee. Attends other Board committee meetings. **Current directorships/partnerships:** **Chair**: Qantas Airways Limited, Australian Football League Commission, Channel 7 Telethon Trust and West Australia Symphony Orchestra. **Member**: Evans and Partners Investment Committee. **Directorships/partnerships/other interests within the past five years**: Wesfarmers Limited (2002 to 2017) and Juvenile Diabetes Research Foundation Australia (2016 to 2021).
Larry Archibald	*BSc (Geosciences), BA (Geology), MBA* **Board Member** **Term of office**: Director since February 2017 **Independent**: Yes **Experience**: Larry previously worked at ConocoPhillips, where he spent eight years in senior executive positions including Senior Vice President, Business Development and Exploration, and Senior Vice President, Exploration. Prior to joining ConocoPhillips, Larry spent 29 years at Amoco (1980 to 1998) and BP (1998 to 2008) in various positions including leading global exploration programmes covering many world regions. **Committee membership**: Audit & Risk, Sustainability and Nominations & Governance Committees. **Current directorships/partnerships:** **Chair**: University of Arizona Geosciences Advisory Board. **Directorships/partnerships/other interests within the past five years**: Mainsail Energy (2016-2018).

Non-Executive Directors	
Name	**Position and Profile**
Frank Cooper, AO	*BCom, FCA, FAICD* **Board Member** **Term of office**: Director since February 2013 **Independent**: Yes **Experience**: Frank has more than 35 years' experience in corporate tax, specialising in the mining, energy and utilities sector. Prior to joining Woodside, Frank was a Partner at PricewaterhouseCoopers. Frank was a partner of Ernst & Young from 2002 to 2005 and managing partner of Arthur Andersen from 1991 to 2002. **Committee membership**: Chair of the Audit & Risk Committee. Member of the Human Resources & Compensation and Nominations & Governance Committees. **Current directorships/partnerships:** **Chair**: Insurance Commission of Western Australia. **Director**: St John of God Australia Limited (since 2015) and South32 Limited (since 2015). **Member**: Pro-Chancellor of Senate of the University of Western Australia. **Trustee**: St John of God Health Care (since 2015). **Directorships/partnerships/other interests within the past five years**: Nil.
Swee Chen Goh	*BSc (Information Science), MBA* **Board Member** **Term of office**: Director since January 2020 **Independent**: Yes **Experience**: Swee Chen previously worked at Shell as Chief Information Officer, Oil Product, East from 2003 until 2004, Vice President of Global IT Services from 2004, and as Chair of Shell Companies in Singapore from October 2014 until her retirement in January 2019. During her tenure at Shell, Swee Chen served on the boards of a number of Shell joint ventures in China, Korea and Saudi Arabia. Prior to joining Shell, Swee Chen worked at Procter & Gamble and IBM. **Committee membership**: Member of the Human Resources & Compensation, Sustainability and Nominations & Governance Committees. **Current directorships/partnerships:** **Chair**: Nanyang Technological University (since 2021), Singapore Institute for Human Resource Professionals (since 2016) and the National Arts Council Singapore (since 2019). **Director**: Singapore Airlines Ltd (since 2019), Singapore Power Ltd (since 2019), Carbon Solutions Holdings Pte Ltd (since 2022), Carbon Solutions Platform Pte Ltd (since 2022), JTC Corporation (since 2022), CapitaLand Investment Ltd (since 2017), Resilience Collective Ltd (since 2020) and The Centre for Liveable Cities (since 2021). **Member**: Singapore Legal Services Commission. **President**: Global Compact Network Singapore. **Directorships/partnerships/other interests within the past five years**: Various Asian Shell Subsidiaries (2014-2018).

Non-Executive Directors	
Name	**Position and Profile**
Ian Macfarlane	*Former Australian Federal Minister (Resources; Energy; Industry and Innovation), FAICD* **Board Member** **Term of office**: Director since November 2016 **Independent**: Yes **Experience**: Ian served as Australia's longest-serving Federal Resources and Energy Minister and the Coalition's longest-serving Federal Industry and Innovation Minister with over 14 years of experience in both Cabinet and shadow ministerial positions. Before entering politics, Ian's experience included agriculture, and being President of the Queensland Graingrowers Association (1991 to 1998) and the Grains Council of Australia (1994 to 1996). **Committee membership**: Member of the Human Resources & Compensation, Sustainability and Nominations & Governance Committees. **Current directorships/partnerships:** **Chief Executive:** Queensland Resources Council (since 2016). **Chair:** Innovative Manufacturing Co-operative Research Centre. **Director:** CSIRO (since 2021). **Member:** Toowoomba Community Advisory Committee of the University of Queensland Rural Clinical School. **Directorships/partnerships/other interests within the past five years**: METS Ignited Ltd**.**
Christopher Haynes, OBE	*BSc, DPhil, FREng, CEng, FIMechE, FIEAust* **Board Member** **Term of office**: Director since June 2011 **Independent**: Yes **Experience**: Christopher had a 38-year career with Shell including as Executive Vice President, Upstream Major Projects within Shell's Projects and Technology business, General Manager of Shell's operations in Syria and a secondment as Managing Director of Nigeria LNG Ltd. From 1999 to 2002, Christopher was seconded to Woodside as General Manager of the North West Shelf Venture. Christopher retired from Shell in August 2011. **Committee membership**: Member of the Audit & Risk, Sustainability and Nominations & Governance Committees. **Current directorships/partnerships:** **Director**: Worley Limited (since 2012). **Fellow:** Institution of Mechanical Engineers in the United Kingdom, a Fellow of the Institution of Engineers, Australia and a Fellow of the Royal Academy of Engineering in the United Kingdom. **Directorships/partnerships/other interests within the past five years**: Nil.

Non-Executive Directors	
Name	**Position and Profile**
Ann Pickard	*BA, MA* **Board Member** **Term of office**: Director since February 2016 **Independent**: Yes **Experience**: During her 15-year tenure prior to retiring from Shell in 2016, Ann served as Executive Vice President Arctic, Executive Vice President Exploration and Production, Country Chair of Shell in Australia, and as Executive Vice President Africa. Ann additionally served as Director, Global Business and Strategy and was a member of the Shell Gas & Power Executive Committee. Prior to joining Shell in 2000, Ann had an 11-year tenure with Mobil prior to its merger with Exxon in 1998. **Committee membership**: Chair of the Sustainability Committee. Member of the Human Resources & Compensation and Nominations & Governance Committees. **Current directorships/partnerships:** **Director**: KBR Inc. (since 2015) and Noble Corporation plc (since 2021). **Member**: Chief Executive Women and University of Wyoming Foundation Board. **Directorships/partnerships/other interests within the past five years**: Nil.
Gene Tilbrook	*BSc, MBA, FAICD* **Board Member** **Term of office**: Director since December 2014 **Independent**: Yes **Experience**: Gene served as a senior executive of Wesfarmers Limited between 1985 and 2009, including roles as Executive Director Finance and Executive Director Business Development. **Committee membership**: Chair of the Human Resources & Compensation Committee. Member of the Audit & Risk and Nominations & Governance Committees. **Current directorships/partnerships:** **Director**: Orica Limited (since 2013). **Directorships/partnerships/other interests within the past five years**: GPT Group Limited (2010-2021).

Non-Executive Directors	
Name	**Position and Profile**
Sarah Ryan	*BSc (Geology), BSc (Geophysics) (Hons 1), PhD (Petroleum and Geophysics), FTSE* **Board Member** **Term of office**: Director since December 2012 **Independent**: Yes **Experience**: Sarah has more than 30 years' experience in the oil and gas industry in various technical, operational and senior management positions. Prior to joining Woodside, Sarah worked at Schlumberger Ltd for 15 years. Sarah was also an equity analyst, portfolio manager and energy adviser for Earnest Partners from 2007 to 2017. Sarah is a Fellow of the Australian Academy of Technology and Engineering. **Committee membership**: Member of the Audit & Risk, Sustainability and Nominations & Governance Committees. **Current directorships/partnerships:** **Director**: Aurizon Holdings (since 2019), MPC Kinetic Pty Ltd (since 2016), Viva Energy Group Ltd (since 2018), Future Battery Industries Co-operative Research Centre (since 2020) and Oz Minerals Limited (since 2021). **Member**: Chief Executive Women (since 2016) and ASIC Corporate Governance Consultative Panel (since 2019). **Directorships/partnerships/other interests within the past five years**: Central Petroleum Limited (2017 to 2018) and Akastor ASA (2014 to 2021).
Ben Wyatt	*LLB, MSc* **Board Member** **Term of Office:** Director since June 2021 **Independent:** Yes **Experience:** Prior to joining Woodside, Ben served in the Western Australian Legislative Assembly for 15 years, including as the Western Australian Treasurer, Minister for Finance, Energy, Aboriginal Affairs and Lands. Ben additionally held various shadow cabinet portfolios including responsibility for Native Title and the Pilbara. Prior to entering Parliament, Ben practised as a lawyer in both private practice and with the Western Australian Office of the Director of Public Prosecutions. **Committee membership:** Member of the Human Resources & Compensation Committee, Sustainability Committee and Nominations & Governance Committee. **Current directorships/partnerships:** **Director:** Wyatt Martin Pty Ltd (since 2021), the West Coast Eagles (since 2021), the Telethon Kids Institute (since 2021), Rio Tinto Limited (since 2021) and Perth International Arts Festival (since 2021). **Member:** UWA Business School Advisory Board and APM Advisory Board. **Directorships/partnerships/other interests within the past five years:** Nil.

Executive Committee	
Name	**Position and Profile**
Meg O'Neill	Please refer to the Executive Director table above.
Graham Tiver	**Executive Vice President and Chief Financial Officer** **Joined Woodside:** 2022 **Experience:** Graham commenced with Woodside in February 2022 as Chief Financial Officer and Executive Vice President. Before joining Woodside, Graham was previously at BHP where he held the role of Group Financial Controller with responsibility for BHP's global accounting and reporting function and financial improvement across 10 countries. Graham has held significant financial, commercial and leadership roles across a range of business sectors, including minerals and oil and gas. He has extensive international experience, having worked in North and South America as well as a variety of roles around Australia. Graham holds a Bachelor of Business in Accounting and Finance from Edith Cowan University in Perth, and is a Fellow of the Australian Society of Certified Practising Accountants. **Current directorships/partnerships:** **Director**: Nil. **Fellow:** Australian Society of Certified Practising Accountants. **Directorships/partnerships/other interests within the past five years:** BHP Foundation (2019-2022).
Shaun Gregory	**Executive Vice President New Energy** **Joined Woodside**: 1995 **Experience**: Shaun has been nominated to lead New Energy, based in Perth. Shaun has over 25 years industry experience. He joined Woodside in 1995 and currently holds the role of EVP Sustainability and Chief Technology Officer, overseeing exploration, technology, digital, new energy and carbon management. Shaun has previously held a range of roles at Woodside across sustainability and exploration. Shaun has a Bachelor of Science (Hons) from the University of Western Australia in Mathematical Geophysics and a Master of Business and Technology from the University of New South Wales. **Current directorships/partnerships:** **Director**: Scitech WA. **Directorships/partnerships/other interests within the past five years**: Dean's Council for the Faculty of Engineering, Computing and Mathematics at the University of Western Australia.

Executive Committee	
Name	**Position and Profile**
Fiona Hick	**Executive Vice President Australia Operations** **Joined Woodside**: 2001 **Experience**: Fiona has been nominated to lead Australian Operations, based in Perth. Fiona has led Woodside's operations division since 2019. As Executive Vice President Operations, she is responsible for all of Woodside's global health, safety and environment, operations, producing facilities, subsea and pipelines, logistics and reservoir management functions. Fiona has been with Woodside since 2001, holding positions including Vice President Strategy Planning and Analysis and Vice President Health, Safety, Environment and Quality. Prior to joining Woodside, Fiona worked for several years with Rio Tinto, living and working in their remote locations. Fiona has a Bachelor of Engineering (Hons) and a Bachelor of Applied Science (Energy). **Current directorships/partnerships:** **Director**: C02CRC. **Member**: Strategic Resources Committee of The University of Western Australia. **Associate Fellow**: The Australian Institute of Management. **Fellow**: Institute of Engineers. **President**: The Chamber of Minerals and Energy of Western Australia. **Directorships/partnerships/other interests within the past five years**: Nil.
Daniel Kalms	**Senior Executive Vice President Merger Integration** **Joined Woodside:** 2001 **Experience**: Daniel is currently Senior Vice President Merger Integration Planning at Woodside, and he has been nominated to lead Merger Integration activities after completion of the Merger, based in Perth. Daniel joined Woodside in 2001 and has 20 years' experience in the oil and gas industry. Since joining Woodside in 2001, Daniel gained extensive experience across departments including commercial, development, projects, operations, and business management. Daniel was Pluto Plant Manager based in Karratha from 2011 to 2014, overseeing the start-up of the new LNG production facility. Daniel graduated from Royal Melbourne Institute of Technology and holds a Bachelor of Engineering (Chemical), Graduate Certificate in Project Management and a Master of Business Administration. **Current directorships/partnerships:** Nil. **Directorships/partnerships/other interests within the past five years**: Nil.
Mark Abbotsford	**Executive Vice President Marketing and Trading** **Joined Woodside**: 2002 **Experience**: Mark has been nominated to lead Marketing and Trading, based in Perth. Mark joined Woodside in 2002, and has 20 years of commercial, marketing, trading and mergers and acquisitions experience across roles based in Australia, Singapore, Japan and the United Kingdom. Mark has held a number of senior positions at Woodside, including Executive Adviser to the Chief Executive Officer and Managing Director, Vice President Marketing, Trading and Shipping and Group Financial Controller. Mark's prior experience includes roles at the Western Australian Department of Treasury and BHP Iron Ore. Mark graduated from the Advanced Management Programme at Harvard Business School in 2021. Mark also holds a Master of Philosophy in Finance from the University of Cambridge, and a Bachelor of Economics (1.Hons) and MBA from the University of Western Australia. **Current directorships/partnerships:** Chamber of Commerce and Industry (WA), GLX Digital Limited, North West Shelf Liaison Company Pty Ltd, North West Shelf Gas Pty. Limited, North West Shelf Shipping Services Company Pty. Ltd. **Directorships/partnerships/other interests within the past five years**: Nil.

Executive Committee	
Name	**Position and Profile**
Shiva McMahon	**Executive Vice President International Operations** **Joined Woodside**: Expected following Implementation **Experience**: Shiva has been nominated to lead International Operations, based in Houston. Shiva is currently General Manager, BHP Petroleum, Australia. Shiva joined BHP in the role of Vice President Finance for Petroleum in 2020 with over 25 years of energy industry experience across multiple international roles. She also served as a Non-Executive Director and member of the Audit, Remuneration and Nominations committees of the Mumbai Stock Exchange listed Castrol India between 2017 and 2018. Shiva spent a large part of her career with BP in upstream and downstream leadership roles including serving as the CFO for BP Trinidad and Tobago and BP's global lubricants business – Castrol. She also served as Head of the Upstream Executive Office between 2014 and 2017. Shiva has a Masters in Business Administration and IT and a Bachelor of Arts in Applied Foreign Languages. **Current directorships/partnerships:** APPEA Director and Chair of Environment, Health and Safety Committee. **Directorships/partnerships/other interests within the past five years**: Castrol India (2017-2018).
Matthew Ridolfi	**Executive Vice President Projects** **Joined Woodside**: Expected following Implementation **Experience**: Matthew has been nominated to lead Projects, based in Houston. Matthew has 30 years of experience in the petroleum business, including in Australia, the United Kingdom, and the United States of America. Matthew is currently the Vice President of Major Developments with accountability for Petroleum's worldwide operated and non-operated major development activities and all operated well and seismic delivery activities. Prior to his current position, Matthew has held various senior roles in both the conventional and shale businesses, and was the Vice President Health, Safety, Environment and Community, and the Joint Interest Unit Manager Bass Strait. Matthew began his career with BHP in 1991 when he joined as a graduate engineer. Matthew holds a bachelor's degree in Mechanical Engineering (Hons). **Current directorships/partnerships:** Nil. **Directorships/partnerships/other interests within the past five years**: Nil.
Andy Drummond	**Executive Vice President Exploration and Development** **Joined Woodside**: Expected following Implementation **Experience**: Andy has been nominated to lead Exploration and Development, based in Houston. Andy is currently Vice President of Sustainability and Innovation for BHP's Petroleum business. Since joining BHP in January 2013, he has held several leadership positions including Vice President Business Development. Prior to joining BHP, Andy spent 15 years with Marathon Oil Corporation working throughout the value chain at various international locations including Scotland, Norway, Equatorial Guinea and Poland. Andy has a Bachelor of Engineering, Chemical and Process Engineering (Hons). **Current directorships/partnerships:** Nil. **Directorships/partnerships/other interests within the past five years**: Nil.

Executive Committee	
Name	**Position and Profile**
Julie Fallon	**Senior Vice President Corporate Services** **Joined Woodside**: 1998 **Experience**: Julie has been nominated to lead Corporate Services, based in Perth. Julie joined Woodside in 1998 and is currently Acting Senior Vice President Corporate and Legal, providing support across the company in a range of areas including corporate affairs, security, legal, property management, risk and compliance and internal audit. Julie has 29 years of industry experience and has held a number of roles within Woodside including Senior Vice President Engineering, Senior Vice President Pluto Business Unit and Senior Vice President Internal Audit. Julie has also worked in a range of production and engineering roles, including several years living and working in Karratha. Prior to joining Woodside, Julie worked as an engineer at Shell Refining Australia. Julie graduated from the University of Sydney with a Bachelor in Chemical Engineering (1. Hons) and is a fellow of the Institution of Chemical Engineers. **Current directorships/partnerships:** **Director**: Nil. **Fellow**: Institution of Chemical Engineers. **Directorships/partnerships/other interests within the past five years**: Nil.
Tony Cudmore	**Senior Vice President Strategy and Climate** **Joined Woodside**: Expected following Implementation **Experience**: Tony has been nominated to lead Strategy and Climate, based in Perth. Tony is currently Group Sustainability and Public Policy Officer for BHP Group. Tony has held responsibility for BHP's global sustainability and climate change teams as well as being accountable for BHP's global brand, corporate communications and public policy advocacy. Tony joined BHP in February 2014 and has held roles including Chief Public Affairs Officer and President Corporate Affairs before assuming his current role in March 2016. Prior to joining BHP, Tony worked with ExxonMobil for 13 years and held a wide range of senior and global Corporate Affairs roles in Australia and the United States of America. Before joining ExxonMobil, Tony was a Media Relations and Policy Adviser before becoming Principal Adviser to the then Premier of Victoria, Jeff Kennett, followed by his role as Assistant Director of the Australian Institute of Petroleum. Tony holds a Bachelor of Arts and a Graduate Certificate of International Relations. **Current directorships/partnerships:** BHP Foundation (2015 - 2022). **Directorships/partnerships/other interests within the past five years**: Nil.

None of the Woodside Directors or Senior Executives:

- has any convictions in relation to fraudulent offences for at least the previous five years;
- has been associated with any bankruptcy, receivership, liquidation or administration while acting in the capacity of a member of the administrative, management or supervisory body or of a senior manager of any company for at least the previous five years;
- has been subject to any official public incriminations and/or sanctions by any statutory or regulatory authority (including designated professional bodies) for at least the previous five years;
- has ever been disqualified by a court from acting as a director of a company, or from acting as a member of the administrative, management or supervisor bodies of a company, or from acting in the management or conduct of the affairs of any company for at least the previous five years; or
- was selected to act in such capacity pursuant to any arrangement or understanding with any shareholder, customer, supplier or other person having a business connection with the Woodside Group.

There are no family relationships between any of the Woodside Directors or Senior Executives.

There are no potential or actual conflicts of interest between any duties owed by the Woodside Directors or the Senior Executives to Woodside and their respective private interests and/or other duties, save for their interest as holders of securities of Woodside.

There are restrictions on the disposal of shares acquired by Non-Executive Directors under the NEDSP. A Non-Executive Director cannot dispose of their shares acquired under the NEDSP for a period of 10 years from acquisition of the shares while they remain a non-executive director, without the Board's consent.

2 Corporate Governance

2.1 Overview

This paragraph explains how the Woodside Board oversees the management of Woodside's business. The Woodside Board does not anticipate any material changes to this approach to management following Implementation.

The Woodside Board is responsible for the overall corporate governance of Woodside, including providing leadership and strategic guidance for Woodside and its related entities. The Woodside Board monitors the operational and financial position and performance of Woodside and oversees the implementation of Woodside's strategic objectives, including approving operating budgets and significant expenditure. The Woodside Board is committed to maximising performance, generating appropriate levels of shareholder value and financial return and sustaining the growth and success of Woodside.

The Woodside Board seeks to ensure that Woodside is properly managed to protect and enhance the interests of Woodside Shareholders, and that Woodside and its Directors, officers and personnel operate in an environment of appropriate corporate governance. The Woodside Board has created a framework for managing Woodside, including adopting relevant internal controls, risk management processes and corporate governance policies and practices which it believes are appropriate for Woodside's business and which are designed to promote the responsible management and conduct of Woodside.

As an ASX-listed entity, Woodside must comply with the Corporations Act, the ASX Listing Rules, and other applicable Australian and international laws. The ASX Listing Rules require Woodside to report on the extent to which it has followed the Corporate Governance Recommendations contained in the fourth edition of the ASX Corporate Governance Council's Principles and Recommendations ("**ASX Recommendations**"). This information is set out in a Corporate Governance Statement and reports on Woodside's key governance principles and practices. These principles and practices are reviewed regularly and revised as appropriate to reflect changes in law and developments in corporate governance. A copy of the Corporate Governance Statement is available in the Corporate Governance section of Woodside's website at www.woodside.com.au.

Throughout the year 31 December 2021, Woodside has complied with all ASX Recommendations. Following Implementation, the Merged Group will continue to pursue Woodside's high level of corporate governance and foster a culture that values ethical behaviour, integrity and respect.

The Board

Composition of the Woodside Board

The Woodside Board is comprised of the Non-Executive Woodside Directors and one Executive Woodside Director, being the Chief Executive Officer and Managing Director. Detailed biographies of the Woodside Directors are provided in Part 12 *(Directors, Senior Executives and Corporate Governance)* of this Prospectus. The Woodside Constitution provides that Woodside is not to have more than 12, nor less than three, directors on the Woodside Board.

Independence of the Woodside Board

Each Woodside Director must bring an independent view and judgement to the Woodside Board and must declare all actual or potential conflicts of interest on an ongoing basis. Any issue concerning a Woodside Director's ability to properly act as a Woodside Director must be discussed at a Woodside Board meeting as soon as practicable.

The Woodside Board assesses independence of the Woodside Directors with reference to whether a director is non-executive, not a member of management and is free of any business or other relationship that could materially interfere with, or could reasonably be perceived to materially interfere with, the independent exercise of their judgement. The Woodside Board has adopted a definition of independence that is based on the definition set out in the ASX Recommendations. The Woodside Board reviews the independence of Woodside Directors before they are appointed, on an annual basis and at any other time where the circumstances of a Woodside Director change such as to require reassessment.

The Woodside Board considers that each of the Non-Executive Woodside Directors (Richard Goyder, Larry Archibald, Frank Cooper, Swee Chen Goh, Ian Macfarlane, Christopher Haynes, Ann Pickard, Gene Tilbrook, Sarah Ryan and Ben Wyatt) are free from any interest, position, association or relationship that might influence or reasonably be perceived to influence, the independent exercise of the Woodside Director's judgement and that each of them is able to fulfil the role of independent Woodside Director for the purposes of the ASX Recommendations.

Meg O'Neill is considered by the Woodside Board not to be independent on the basis that she is the Chief Executive Officer and Managing Director of Woodside.

Accordingly, the Woodside Board consists of a majority of independent directors as recommended in ASX Recommendation 2.4.

The Woodside Board will continue to regularly review the independence of each Woodside Director, and any subsequent Woodside Directors appointed, in light of interests disclosed to the Woodside Board and will disclose any change to the ASX, as required by the ASX Listing Rules. The Policy on Independence of Woodside Directors is available in the Corporate Governance section of Woodside's website at www.woodside.com.au.

Woodside Board Charter

The Woodside Board has adopted a written charter ("**Charter**") to provide a framework for the effective operation of the Woodside Board, which sets out the roles and responsibilities of the Woodside Board, which include but are not limited to:

- Culture and responsible decision-making (e.g. setting Woodside's values and standards of conduct, promoting ethical and responsible decision-making and monitoring its compliance with legal and regulatory requirements):
  - strategy and performance (e.g. setting the strategy objectives of Woodside and approving major corporate initiatives and Woodside Board policies);
  - oversight of management (e.g. monitoring and assessing management's performance in carrying out Woodside strategies, achieving objectives and observing budgets);
  - risk management and compliance (e.g. reviewing and ratifying systems of risk management, compliance and control);
  - oversight of financial and capital management (e.g. approving budgets, determining the dividend policy of Woodside, and monitoring financial results and audit arrangements);
  - people and diversity (e.g. establishing and assessing objectives for achieving gender diversity, and maintain an orderly succession of appointments of Woodside Non-executive Directors); and
  - security holders (e.g. promoting effective engagement with security holders in providing them with appropriate information and monitoring Woodside's process for making timely and balanced disclosure of all material information);
- the role and responsibilities of the Chair and company secretary;
- the delegations of authority of the Woodside Board to the Woodside Board committees and the Chief Executive Officer and Managing Director;
- the membership of the Woodside Board, including in relation to the Woodside Board's composition, the election of Woodside Directors, and conduct of individual Woodside Directors;
- Woodside Board processes, including how the Woodside Board meets; and
- the Woodside Board's performance evaluation processes, including in respect of its own performance, and the performance of the Woodside Board committees and individual Woodside Directors (including the Chair and the Chief Executive Officer and Managing Director).

The Woodside Board will review the Charter regularly, and make amendments, as necessary. The Charter is available in the Corporate Governance section of Woodside's website at www.woodside.com.au.

Committees

The Woodside Board may from time to time establish standing and ad hoc committees to assist it in carrying out its responsibilities. As set out below, the Woodside Board has established four standing committees to facilitate and assist the Woodside Board in fulfilling its responsibilities:

- Audit & Risk Committee;
- Nominations & Governance Committee;
- Human Resources & Compensation Committee; and
- Sustainability Committee.

Each committee is comprised of independent Non-Executive Woodside Directors in compliance with ASX Listing Rules and ASX Recommendations. The committees operate principally in a review or advisory capacity, except in cases where powers are specifically conferred on a committee by the Woodside Board.

Each committee has the responsibilities described in the relevant committee charter adopted by Woodside (each of which has been prepared having regard to the ASX Recommendations). Each committee's charter is available in the Corporate Governance section of Woodside's website at www.woodside.com.au.

Woodside does not currently expect any change to the composition of these committees following Implementation.

Committee	Roles and responsibilities	Composition
Audit & Risk Committee	The role of the Audit & Risk Committee is to assist the Woodside Board to meet its oversight responsibilities in relation to Woodside's financial reporting, compliance with legal and regulatory requirements, internal control structure, risk management and insurance procedures and the internal and external audit functions. Key duties of this committee include overseeing: • Woodside's internal control and risk management, including the effectiveness of the Woodside reporting and internal control policies and risk management framework; • Woodside's internal audit process, including the appointment of head of internal audit and approving audit planning programme; • Woodside's external audit process, including appointment, independence, management and removal of Woodside's external auditor; and	The Audit & Risk Committee shall comprise only Non-Executive Woodside Directors, have at least three members (the majority of which are independent) and be chaired by an independent director (who is not the chair of the Woodside Board). The Woodside Directors serving on this committee must be financially literate, with at least one director with experience in the oil and gas industry. Current composition: Frank Cooper (chair) Larry Archibald Christopher Haynes Sarah Ryan Gene Tilbrook All members of this committee are Independent Non-Executive Woodside Directors

Committee	Roles and responsibilities	Composition
	• Woodside's financial statements, reporting responsibilities and other relevant matters. The Audit & Risk Committee meets at least five times each year (with two meetings specifically held to review the half year and annual accounts), with additional meetings when circumstances require, as determined by the committee chair.	
Nominations & Governance Committee	The role of the Nominations & Governance Committee is to assist the Woodside Board to review the composition, performance and succession planning of the Woodside Board. This includes identifying, evaluating and recommending candidates for the Woodside Board. Duties of this committee include: • reviewing the size and composition of the Woodside Board, including succession plans, to enable an appropriate mix of skills, experience, expertise and diversity to be maintained; • identifying and evaluating Woodside Board candidates and recommending to the Woodside Board individuals for board appointment/ shareholder election; • developing the appropriate process for evaluation of the performance of the Woodside Board and its committees, each Non-Executive Woodside Director and the Chair; • reviewing and recommending to the Woodside Board corporate governance policies of Woodside; • monitoring and advising the Woodside Board of significant developments in applicable corporate governance laws, regulations and practices; and • reviewing and recommending to the Woodside Board annual Corporate Governance Statement and other corporate	The Nominations & Governance Committee shall be members of and appointed by the Woodside Board and shall comprise only Non-Executive Woodside Directors; have at least three members (the majority of which are independent); be chaired by an independent director . Current composition: Richard Goyder (chair, also Chair of the Woodside Board) Larry Archibald Frank Cooper Swee Chen Goh Christopher Haynes Ian Macfarlane Ann Pickard Sarah Ryan Gene Tilbrook Ben Wyatt All members of this committee are Independent Non-Executive Woodside Directors

Committee	Roles and responsibilities	Composition
	governance disclosures of Woodside. The Nominations & Governance Committee shall meet at least twice each year, with additional meetings when circumstances require, as determined by the committee chair.	
Human Resources & Compensation Committee	The role of the Human Resources & Compensation Committee is to assist the Woodside Board in establishing human resources and compensation policies and practices. Duties of this committee include: • reviewing and making recommendations to the Woodside Board on Woodside's remuneration policies and practices generally, including superannuation and equity awards; • reviewing and making recommendations to the Woodside Board on Woodside's diversity policies and practices; • overseeing the formulation and reviewing Woodside's recruitment, organisational development, retention, succession and termination policies generally; • considering whether, and if so when, shareholder approval of aspects of the remuneration policy is required; and • ensuring that Woodside meets its obligations in respect of remuneration matters as required under the ASX Listing Rules and the Corporations Act, including Woodside's disclosure obligations. The Human Resources & Compensation Committee shall meet as frequently as required but not less than twice each year. Any member or the secretary of the committee may call a meeting.	The Human Resources & Compensation Committee shall be members of, and appointed by, the Woodside Board and shall comprise only Non-Executive Woodside Directors; have at least three members (the majority of which are independent); be chaired by an independent director (who is not the chair of the Woodside Board). Current composition: Gene Tilbrook (chair) Frank Cooper Swee Chen Goh Ian Macfarlane Ann Pickard Ben Wyatt All members of this committee are Independent Non-Executive Woodside Directors
Sustainability Committee	The role of the Sustainability Committee is to assist the Woodside Board to meet its oversight	The Sustainability Committee shall be members of, and appointed by, the Woodside Board and shall

Committee	Roles and responsibilities	Composition
	responsibilities in relation to Woodside's sustainability policies and practices, including policies regarding climate change, at times similar to Woodside's Climate Change Policy. See "Conduct Policies" below. The duties of this committee include reviewing, and making recommendations to the Woodside Board on, Woodside's policy and performance in relation to sustainability-related matters, including: • health and safety; • process safety; • the environment; • climate change; • human rights; • heritage and land access; • security and emergency management; and • community relations. The Sustainability Committee shall meet at least four times each year, with additional meetings when circumstances require, as determined by the committee chair.	comprise only Non-Executive Woodside Directors; have at least three members (the majority of which are independent); be chaired by an independent director. At least one member of the committee must possess appropriate skills in sustainability-related matters. Current composition: Ann Pickard (chair) Larry Archibald Swee Chen Goh Christopher Haynes Ian Macfarlane Sarah Ryan Ben Wyatt All members of this committee are Independent Non-Executive Woodside Directors

Corporate Governance Policies

Woodside has also adopted the following policies, each of which has been prepared having regard to the ASX Recommendations and is available in the Corporate Governance section of Woodside's website at www.woodside.com.au. Woodside's corporate governance policies will continue to be reviewed regularly and will continue to be developed and refined as required to meet the needs of Woodside.

Following Implementation, the Merged Group will be subject to the Woodside corporate governance policies, which, upon admission to any secondary exchange, will also be compliant with the rules of that relevant exchange and any required international legislation.

Continuous disclosure and Market Communications Policy

Woodside is required to comply with the continuous disclosure requirements of the ASX Listing Rules and the Corporations Act. Subject to the exceptions contained in the ASX Listing Rules, Woodside is required to immediately disclose to the ASX any information concerning Woodside which a reasonable person would expect to have a material effect on the price or value of Woodside Shares. Woodside is committed to observing its disclosure obligations under the ASX Listing Rules and the Corporations Act.

The Woodside Board has adopted a Continuous Disclosure and Market Communications Policy which establishes procedures aimed at ensuring that Woodside Directors, management, and other relevant staff are aware of and fulfil their obligations in relation to the timely disclosure of material price sensitive information. Under the Continuous Disclosure and Market Communications Policy, Woodside has established a Disclosure Committee, comprised of senior managers of Woodside including its Chief Executive Officer and Managing

Director, Chief Financial Officer, Senior Vice Present Corporate & Legal, General Counsel (Chair), Vice President Investor Relations, and Vice President Corporate Affairs or their delegate. The Disclosure Committee has authority to decide whether a market announcement needs to be made and to approve the form of any announcement made and is also responsible for the development of guidelines for the release of information and implementing reporting processes and controls.

Woodside intends to adopt, with effect from admission to the LSE and NYSE, amendments to the Continuous Disclosure and Market Communications Policy to ensure that the Merged Group also complies with its continuous disclosure obligations under U.S. securities laws, MAR and the DTR.

Securities Dealing Policy

The Woodside Board has adopted a Securities Dealing Policy which explains the prohibited type of conduct in relation to dealings in securities under the Corporations Act and is intended to establish a best-practice procedure in relation to the dealings in Woodside Shares by Executive and Non-Executive Woodside Directors, employees (full-time, part-time and casual), contractors, consultants and advisers of Woodside.

The Securities Dealing Policy sets out the restrictions that apply to dealing with Woodside Shares and other Woodside securities (as defined in the policy) including 'black-out periods', during which Woodside Directors and restricted employees are generally prohibited from dealing in Woodside Shares and other Woodside securities, along with a procedure under which a Woodside Director or restricted employee is required to submit a request and obtain written clearance prior to dealing in Woodside Shares and other Woodside securities outside the black-out periods.

The policy further provides that any persons to whom the policy applies must not engage, directly or indirectly, in short-term or speculative dealing in Woodside Shares and other Woodside securities.

Woodside will adopt, with effect from admission to the LSE and NYSE, amendments to the Securities Dealing Policy to ensure that the Merged Group also complies with its obligations under U.S. securities laws, MAR and the DTR.

Conduct policies

The Woodside Board recognises the need to observe the highest standards of corporate practice and business conduct. Accordingly, the Woodside Board has adopted a number of policies which, together, set standards of conduct in relation to the operation of Woodside. These policies are to be followed by the Woodside Board along with all employees, officers, contractors, consultants and other persons that act on behalf of Woodside and associates of Woodside. Woodside currently has the following conduct policies in place:

- Anti-Bribery and Corruption Policy
- Climate Change Policy
- Code of Conduct
- Health, Safety and Environment Policy
- Human Rights Policy
- Indigenous Communities Policy
- Quality Policy
- Sustainable Communities Policy
- Whistleblower Policy
- Working Respectfully Policy

These and other associated policies set out Woodside's approach to various matters including obligations to act honestly, fairly, professionally and respectfully; conflicts of interest; appropriate use of Woodside's property; anti-bribery and giving or acceptance of gifts; prohibition on facilitation payments; dealings with politicians and government officials in the context of the giving or acceptance of gifts; political and charitable donations; confidentiality; privacy; discrimination, bullying, harassment and vilification; health and safety of employees; whistleblower protections and compliance with laws and regulations in respect of these matters. All new and existing Woodside staff are trained at induction and annually on the code of conduct and related policies.

Inclusion and Diversity Policy

The Woodside Board has approved an Inclusion and Diversity Policy in order to, among other matters, provide a framework by which Woodside will support and facilitate an environment of diversity and inclusion across the organisation.

Woodside's key priority is to drive inclusive leadership and create an inclusive culture for all employees. Woodside is committed to improving the diversity mix of its workforce to reflect the communities in which it operates. Woodside recognises that substantive equality measures are required for some groups to achieve equal levels of participation and inclusion in the workplace. Woodside's diversity focus areas are gender, Australian First Nations, gender identity and sexual orientation, cultural background and faith, local people globally and differently abled groups.

Risk Management Policy

Woodside recognises that risk is inherent in its business and the effective management of risk is vital to deliver its strategic objectives, continued growth and success. Woodside is committed to managing risks in a proactive and effective manner as a source of competitive advantage. The objective of the Woodside risk management framework is to provide a single consolidated view across the organisation to understand its full risk exposure and prioritise risk management and governance.

Woodside's Managing Director is accountable to the Woodside Board for ensuring the effective implementation of the Risk Management Policy.

Part 13 – Regulatory Overview

This section sets out the regulatory environment that Woodside and BHP Petroleum operate in and that may materially affect each of Woodside and BHP Petroleum's businesses.

Woodside and BHP are subject to a broad range of laws and regulations imposed by governments and regulatory bodies. These regulations touch all aspects of each of Woodside and BHP Petroleum's assets, including how Woodside and BHP extract, process and explore for oil and natural gas and how Woodside and BHP conduct their businesses, including regulations governing matters such as environmental protection, land rehabilitation, occupational health and safety, human rights, the rights and interests of Indigenous peoples, competition, foreign investment, export, marketing of oil and natural gas and taxes.

This summary focuses on the Australian and United States regulatory regimes. The summary is not a full summary of the regulatory regimes in those jurisdictions nor is it a complete list of the legislation and regulation that applies to each of Woodside and BHP.

1. Regulatory and legislative framework in Australia

Petroleum regime

In Australia, petroleum exploration and development takes place within a legal framework characterised by a division of responsibilities between the federal and the state or territory governments. Exploration and development conducted onshore and within three nautical miles of the territorial sea baseline of the relevant state or territory ("**coastal waters**") are the responsibility of the individual state or territory governments.

The Australian federal government has legislative responsibility for Australian offshore petroleum exploration and production beyond the three nautical mile territorial sea, which encompasses the area of most relevance to Woodside and BHP Petroleum's offshore activities.

Offshore operations beyond coastal waters are primarily governed by the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cth) ("**OPA**") and related legislation. The OPA establishes a joint authority ("**Joint Authority**") whereby relevant Australian state, territory and federal governments cooperate in the administration and supervision of petroleum activities in Australia's offshore areas beyond coastal waters. Within the coastal waters, petroleum operations are covered by the relevant state or Northern Territory legislation that is substantively similar to the OPA. Other state and territory legislation principally covers the establishment and operation of facilities for the processing, production and delivery of gas, LNG and other petroleum products located onshore.

An exploration permit granted under the OPA authorises the holder to explore for, but not to produce commercially, petroleum products (including oil and gas and related products) in the area that is covered by the permit. The Joint Authority selects vacant acreage and makes it available for competitive bidding each year. Exploration permits are awarded based on work programme bids (or, on occasion, a cash bid) for an initial period of six years. The holder of an exploration permit granted under the work programme bidding system is required to complete a minimum guaranteed work programme within the first three years of a permit. The commitments under the work programme must be completed on schedule or the permit may be cancelled.

The holder of an exploration permit may apply for a production licence after a discovery has been made.

The holder of a production licence is entitled to be granted a renewal where the conditions of the licence, the OPA and the regulations applicable to the licence have been complied with. A production licence granted on or after 30 July 1998 remains in force indefinitely (subject to compliance with the licence conditions, the OPA and the regulations). However, the Joint Authority has discretion to terminate such a production licence where no operations for the recovery of petroleum under the licence have been carried on for a continuous period of at least five years.

A person who makes a discovery that is not currently commercially viable but is likely to become commercially viable within 15 years may apply for a retention lease under the OPA. This application must be made within two years after a petroleum location has been declared under the exploration permit, although this period can be extended. A retention lease gives the holder an interest over the discovery, so that if the discovery does become commercially viable at some point, the holder could apply for a production licence. Retention leases are generally granted subject to conditions that relate to appraisal and, in some cases, marketing activities. A retention lease is granted for a period of five years and is renewable subject to certain requirements being met. As with the original grant of a retention lease, applicants for a renewal must be able to demonstrate that their discovery is not commercially viable at the time of the application, but that the discovery is likely to become commercially viable within 15 years.

The OPA requires titleholders to maintain financial assurance (which includes insurance, self-insurance, bonds, bank deposits and other instruments) sufficient to give the titleholder capacity to meet costs, expenses and liabilities arising in connection with, or as a result of, carrying out a petroleum activity. This is intended to apply to the extraordinary costs arising in connection with activities undertaken under a title, for example, expenses relating to the clean-up or other remediation of the effects of an escape of petroleum.

On 2 September 2021, the Australian federal parliament passed the *Offshore Petroleum and Greenhouse Gas Storage Amendment (Titles Administration and Other Measures) Act 2021* (Cth) which, among other changes, amends the OPA to impose new trailing liability and change of control provisions. The amendments took effect on 3 March 2022. The changes to the trailing liability regime expand the existing powers of the regulator (NOPSEMA) and the Minister including the ability to recall any former title holder to undertake decommissioning activities on a title area. These powers are retrospective in their application and apply to titles that are currently in force as well as to titles that ceased to be in force on or after 1 January 2021.

Competition Regulation

Australia's competition laws are contained in the *Competition and Consumer Act 2010* (Cth) ("**CCA**"). The CCA prohibits, amongst other things:

- cartel conduct, which prohibits competitors making or giving effect to a contract, arrangement or understanding that involves price fixing, output restrictions, market sharing or bid rigging;
- a corporation with a substantial degree of power in a market engaging in conduct with the purpose or effect (or likely effect) of substantially lessening competition (misuse of market power); and
- a corporation engaging in a concerted practice, or making or giving effect to a contract, arrangement or understanding that has the purpose or effect (or likely effect) of substantially lessening competition in a market.

The ACCC can specifically authorise certain conduct that might otherwise breach the CCA.

Secondary Petroleum Taxes

The NWS Project remains subject to a royalty on petroleum production after allowing a deduction for certain prescribed expenditures and allowances (including excise taxes). The royalty rate is between 10% and 12.5% on the wellhead value depending on the type of licence that is held. In addition, the NWS Project is also subject to excise on oil/condensate production and the Petroleum Resource Rent Tax ("**PRRT**"). The current excise rate varies between 0% and 55% depending on the type of oil and production rates. There is a 30 million barrel exemption for each field. A top rate of excise of 30% applies to condensate production.

PRRT is imposed under the *Petroleum Resource Rent Tax Act 1987* (Cth) and assessed under the *Petroleum Resource Rent Tax Assessment Act 1997* (Cth). PRRT is payable on the excess of assessable upstream revenue over deductible upstream expenditure (including a return on development capital and exploration expenditures) derived from Australian petroleum projects. PRRT is assessed before company income tax and is deductible for the purpose of calculating company income tax. The PRRT rate is currently 40%.

With effect from 1 July 2012, PRRT was extended to all Australian onshore and offshore oil and gas projects, including the NWS Project, although existing resources taxes are effectively credited against the PRRT liability for a project. On 1 July 2019, new legislation was introduced, pursuant to which:

- the uplift rates that apply to certain categories of carried-forward expenditure is reduced; and
- onshore projects are removed from the scope of the PRRT.

Further, on 5 April 2019, Treasury released a consultation paper on their secondary review into the Gas Transfer Pricing methodology used to calculate the price of gas in integrated LNG projects. The consultation process is now complete, but Treasury has not yet published its review.

On 2 April 2022, new Acts (together the "**Levy Acts**") became effective and introduced a temporary levy on all registered holders of Commonwealth production licences. The levy is set at the lesser of US$0.48 per barrel of oil equivalent or the directed levy amount for each levy year determined by the relevant Commonwealth Minister. The levy is designed to cover the Commonwealth's costs of decommissioning of the Northern Endeavour floating production storage and offtake facility.

Native Title Legislation & Agreements

Since 1992, Australian common law has recognised that, in certain circumstances, indigenous Australians may have rights and interests over land and waters in accordance with their traditional laws and customs.

The *Native Title Act 1993* (Cth) ("**NTA**") recognises and protects the native title rights and interests of native title holders and registered native title claimants. The NTA and complementary state legislation also operates to validate "past acts" and "intermediate period acts" of governments, such as granting of titles, licences and leases, etc. in relation to land or waters in Australia and provides a regime for the valid doing of "future acts" (that is, the making of similar grants) over land or waters in Australia where native title may exist. The grant or renewal of a land, petroleum or pipeline title before 1 January 1994 is classified by the NTA as a "past act" and, if invalid due to the existence of native title, is validated by the NTA and complementary state legislation.

The NTA also protects native title from invalid interference by grants or renewals of land, petroleum or pipeline titles made after 1 January 1994. Grants of these titles post-1 January 1994 are valid if they occur in accordance with the "future act" provisions under the NTA.

Where a granted or renewed title is valid in native title terms, whether because it was always valid, has been validated under the NTA, or is a valid "future act," then that title will prevail over native title, to the extent of any inconsistency, and the title holder may exercise all of its rights and interest under that title. If any granted or renewed title is not in compliance with the NTA, it will be invalid (unless validated pursuant to the NTA), and any existing native title rights and interests will continue. If activities (including grants of tenure/title) occur on land or waters without valid authorisation under the "future act" provisions of the NTA, native title holders have legal remedies available to them to protect their native title rights and interests. Remedies include injunctions to restrain activities and actions for compensation/damages.

The NTA also establishes a process by which native title holders may apply for compensation in relation to the effect of the creation or resumption of an interest in land on their native title rights and interests.

Indigenous and Natural Heritage Legislation & Agreements

Multiple pieces of Australian state and federal government legislation apply to Aboriginal cultural heritage protection / management and Aboriginal rights and access to land in Australia.

The primary legislation currently governing Indigenous cultural heritage in relation to Western Australia is the Aboriginal Heritage Act 1972 (WA) ("**WA AHA**"), which is in the process of being replaced by the Aboriginal Cultural Heritage Act 2021 (WA) ("**ACH Act**"). The ACH Act passed Western Australia's Parliament and received royal assent on 22 December 2021 and has recently commenced in part. The substantive provisions will commence in around 12 to 18 months' time. The equivalent State legislation governing Indigenous cultural heritage in Victoria is the Aboriginal Heritage Act 2006 (Vic) ("**Victorian AHA**").

Commonwealth of Australia legislation governing Indigenous cultural heritage and natural heritage across Australia includes the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cth) ("**ATSIHP Act**") and the *Environment Protection and Biodiversity Conservation Act* 1999 (Cth) ("**EPBC Act**"). Various government approvals, including state and federal environmental approvals, may regulate the impact of an activity on cultural heritage values, including by placing on approval conditions relating to Indigenous cultural heritage.

Arrangements between the Australian Government and the Timor-Leste Government in relation to the GSSR, the JPDA and Greater Sunrise gas fields

Woodside holds production sharing contracts and retention leases covering its petroleum interests within the Greater Sunrise Special Regime ("**GSSR**") under joint Australian/Timor-Leste administrative control. The GSSR was established pursuant to the Maritime Boundaries Treaty, which came into force on 30 August 2019 and the GSSR replaced the Joint Petroleum Development Area ("**JPDA**"). Woodside and the other Sunrise joint venture participants are required to enter into a new production sharing contract.

Environmental Regulation

Woodside and BHP Petroleum's operations are also subject to federal (which include Australian obligations under international conventions), state and local laws and regulations relating to the environment in each of the jurisdictions in which it conducts its business. For offshore petroleum activities, these laws and regulations generally:

- require the acquisition of a permit before activity commences;
- require that for any activities, environmental risks are identified, and controls put in place to reduce or eliminate the risks. For drilling and seismic activities, this is outlined in a government-approved environment plan; as an operation goes into construction, commissioning and production, a revised environment plan may be required to be submitted for approval;
- restrict the type, quantity and concentration of various substances that can be utilised or released into the environment in connection with marine and land-based activities;
- limit or prohibit drilling and seismic or production activities in and near certain environmentally sensitive or protected areas; and
- impose criminal and civil liabilities for pollution resulting from oil, natural gas and petrochemical operations.

The requirements imposed by environmental laws and regulations are subject to change and have tended to become stricter over time. The modification of existing foreign or domestic laws or regulations or the adoption of new laws or regulations curtailing exploratory or development drilling for oil and gas for economic, political, social, environmental or other reasons could have a material adverse effect on Woodside or BHP Petroleum's business, financial condition or results of operations by limiting drilling opportunities.

Following streamlining of regulatory processes under the OPA in 2014, NOPSEMA is the sole environmental regulator for offshore petroleum activities in Commonwealth waters (subject to limited exceptions).

Regulation of Greenhouse Gas Emissions

Legislation was passed on 31 October 2014, to implement a climate change policy called Direct Action. Direct Action operates by:

- crediting Australian-based greenhouse gas emissions reductions and abatement from eligible offsets projects;
- using a government Emissions Reduction Fund (since renamed the "Climate Solutions Fund" or "CSF") to purchase Australian-based greenhouse gas emissions reductions and abatement at auctions; and
- applying a "safeguard" baseline mechanism for large emitters, with penalties for exceedances.

Since 1 July 2016, the "responsible emitter" for a "designated large facility" during all or part of a financial year must register the facility under the *National Greenhouse and Energy Reporting Act 2007* (Cth) ("**National Greenhouse and Energy Reporting Act**") (if not already registered). Generally, a facility will be a "designated large facility" if the total amount of covered emissions during a financial year has a carbon dioxide equivalence ("**CO2e**") in excess of 100kTCO2e.

The responsible emitter must report the total amount of covered emissions for a designated large facility for each "monitoring period." The responsible emitter must also ensure that the total amount of emissions of greenhouse gases from the operation of the facility during the monitoring period (the "net emissions number") does not exceed 100kTCO2e or such higher number ascertained under a "baseline determination" in force for the facility (called the "safeguard mechanism").

The "net emissions number" for a facility may be reduced by the surrender of "prescribed carbon units" in accordance with the procedures under the National Greenhouse and Energy Reporting Act. The only prescribed carbon units currently available under the Direct Action scheme are **ACCUs**. ACCUs can be purchased by the Clean Energy Regulator on behalf of the Commonwealth of Australia via reverse auctions (which have occurred every year from 2015 to 2021). ACCUs are also traded directly between parties on a voluntary basis for a range of purposes.

In May 2020, the Australian Government agreed to investigate and implement a range of mechanisms to enhance and incentivise participation in the CSF. It also announced on 26 October 2021 it will make it easier for plantation and farm forestry projects to generate carbon credits and access the CSF.

The Australian Government committed to reducing emissions by 26% to 28% of 2005 levels by 2030. The Australian Government indicated it would meet this target through policies built on the Direct Action approach such as the Emissions Reduction Fund ("**ERF**") and its Safeguard Mechanism. This target is reflected in Australia's commitment to parties under the United Nations Framework Convention on Climate Change Paris Agreement ("**Paris Agreement**"). The Australian Government has made no formal changes to this target but has stated that according to projection results from 2021, it is on track to exceed it by up to 9 percentage points with an expected reduction in emissions by 30% to 35% by 2030.

On 26 October 2021, the Australian Government released its Long-Term Emissions Reduction Plan which is a whole-of-economy climate change plan to achieve its target of net zero emissions by 2050.

The Australian Government is also exploring a proposed new Safeguard Crediting Mechanism which aims to unlock below-baseline abatement opportunities not currently being realised under the existing framework of the ERF and Safeguard Mechanism. The proposal is to establish a new credit unit type ("**Safeguard Mechanism Credits**" or "**SMCs**") which can be sold to the Australian Government or purchased by third parties to meet either a mandatory obligation under the Safeguard Mechanism or a voluntary carbon commitment as an alternative to ACCUs. A public submission process closed on 5 October 2021, with enabling legislation intended to be in place by 1 July 2022.

Further, the Australian Government announced an Emissions Reduction Fund method in October 2021 to credit abatement from new carbon capture and storage projects. This involves awarding large-scale carbon capture and storage projects that capture and permanently store carbon underground with tradeable high-integrity units (ACCUs). It is a voluntary scheme that aims to provide incentives for a range of organisations and individuals to adapt new practices and technologies to reduce their emissions. One ACCU is earned for each tonne of carbon dioxide equivalent stored or avoided by a project. The Clean Energy Regulator is also in the process of developing an Australian Carbon Exchange that will make the trading of ACCUs simpler.

There is ongoing and increasing public pressure on the government to accelerate its carbon emissions reduction programme. As such, there remains significant uncertainty regarding the future of climate change regulation in Australia and the effect it may have on the Merged Group's business.

Greenhouse gas emissions are also regulated under State-based environmental legislation in both WA and Victoria.

Domestic Gas Policy

In 2006, the Western Australian Government formalised its policy on securing future domestic gas supplies for Western Australia. In 2012, the Government clarified arrangements for the application of the policy in its Strategic Energy Initiative's *Energy2031* final paper ("**Domestic Gas Policy**"). The State of Western Australia will apply the Domestic Gas Policy flexibly in accordance with the following requirements:

- Western Australian LNG producers will commit to make available domestic gas equivalent to 15% of LNG production from each LNG export project by:
  - reserving domestic gas equivalent to 15% of LNG production from each Western Australia-based LNG export project;
  - developing, or obtaining access to, the necessary infrastructure (including a domestic gas plant, associated facilities and offshore pipelines) to meet their domestic gas commitments as part of the State approvals process; and
  - showing diligence and good faith in marketing gas into the Western Australia domestic market.
- These efforts may be subject to independent review.
- LNG producers should undertake the above actions such that domestic gas is made available to coincide with the start of LNG production. This timing may, however, vary depending on project circumstances.
- Prices and contracts for domestic gas will be determined by the market.

- LNG producers may propose to offset their domestic gas commitment by supplying gas or other energy from an alternative source, rather than supplying gas from their LNG projects. Among other conditions, producers will have to demonstrate that the proposed offset represents a net addition to the State's domestic energy supply. The State will consult with industry to develop criteria for domestic gas offsets.
- The intention was to review the Domestic Gas Policy in 2015, but it is understood that this review has not yet been completed by the Western Australian Government.

In August 2020 the Domestic Gas Policy was amended to prevent the export of local WA gas, being onshore gas extracted from Western Australia. Under the updated policy, local WA gas cannot be exported to the eastern states of Australia or overseas. Woodside does not currently extract onshore local gas in WA.

Woodside and its joint venture partners have domestic gas supply agreements with the Western Australia State Government for the Pluto LNG and NWS projects (including with BHP Petroleum as a joint venture partner with respect to the NWS project). In 2015, the NWS State Agreement (*North West Gas Development (Woodside) Agreement 1979)* was amended to include a new domestic gas commitment of 15% (or lesser approved amount) of total LNG quantity approved for use, supply or sale overseas. In 2006, in connection with the Pluto LNG project, Woodside entered into an arrangement with the Western Australia State Government to market and make available for supply a quantity of domestic gas. Woodside is not required to supply domestic gas if it is not commercially viable to do so. In January 2021, Woodside signed an additional domestic gas agreement with the State Government project in which Woodside agreed to make 45.6PJ available for the domestic market, separate and in addition to the 2015 commitment from the NWS Joint Venture. In January 2021, Woodside signed a further agreement with the State Government in relation to the Pluto LNG project processing LNG for export at the NWS facilities in which Woodside agreed to make up to 24.7 PJ available for the domestic market, separate and in addition to the 2015 commitment from the NWS Joint Venture from the NWS project. In November 2021, Woodside and BHP Petroleum signed a further domestic gas agreement with the State Government with respect to the Scarborough and Pluto Train 2 developments pursuant to which, consistent with the WA Domestic Gas Policy, the Scarborough Joint Venture will make gas equivalent to 15% of its LNG exports available to the domestic market.

2. Occupational Health and Safety Legislation

Work health and safety in Australia is currently governed by a number of legislative instruments, covering both state and federal jurisdictions, with separate onshore and offshore regulation.

The work health and safety ("**WHS"**) laws are based on the national model *Work Health and Safety Act 2011* (Cth) ("**WHS Act"**) which now applies in all Australian States and Territories, except Victoria. In Victoria, earlier occupational health and safety (**OHS**) laws still apply, although the basic principles of the legislation is similar.

In short, the WHS laws in each jurisdiction aim to protect people's health and safety at work by imposing obligations on all parties who are in a position to contribute to the management of workplace risks, including manufacturers and suppliers of equipment and substances, as well as employers, workers, contractors and others.

The principal legislation that currently applies in the Commonwealth of Australia waters in relation to Woodside's operations offshore of Western Australia is the OPA and associated regulations.

NOPSEMA is a Commonwealth of Australia Statutory Agency responsible for regulating the health and safety, structural integrity and environmental management of all offshore petroleum facilities in the Commonwealth of Australia's waters, and in coastal waters where regulatory powers and functions have been conferred.

For floating petroleum facilities, the Commonwealth of Australia maritime law, the *Navigation Act 2012* (Cth) and the *Occupational Health and Safety (Maritime Industry) Act 1993* (Cth), may also apply to operations. The Australian Maritime Safety Authority has responsibility for health and safety issues for personnel on prescribed ships engaged in trade or commerce on international and domestic voyages.

3. Regulatory and legislative framework in United States

BHP Petroleum's operations in the United States

BHP Petroleum's exploration and production operations on federal oil and natural gas leases in the U.S. GOM are subject to regulation by the Bureau of Safety and Environmental Enforcement ("**BSEE**"), the Bureau of

Ocean Energy Management ("**BOEM**") and the Office of Natural Resources Revenue ("**ONRR**"), all of which are agencies of the U.S. Department of the Interior ("**DOI**"). These leases are awarded by the BOEM based on competitive bidding and contain relatively standardised terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the federal Outer Continental Shelf Lands Acts ("**OCSLA**"). For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of their operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency ("**EPA**"), lessees must obtain a permit from BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Outer Continental Shelf ("**OCS**"), calculation of royalty payments and the valuation of production for this purpose, and removal of facilities.

Laws and regulations are subject to change, and the trend in the United States over the past decade has been for these governmental agencies to continue to evaluate and, as necessary, develop and implement new, more restrictive permitting and performance requirements. For example, a secretarial order issued by the Biden Administration in 2021 served to temporarily suspend delegation of authority to governmental agencies regarding fossil fuel authorisations on the OCS, but that order specifically excluded authorisations associated with existing operations under valid leases. In addition, President Biden issued an executive order on 27 January 2021 pausing new oil and natural gas leases on federal lands and offshore waters pending review and reconsideration of federal oil and gas permitting and leasing practices. In conducting this review, the Secretary of the Interior shall consider whether to adjust royalties associated with oil and gas resources extracted from public lands and offshore waters to account for corresponding climate costs. However, in June 2021 a federal judge issued a nationwide temporary injunction in a lawsuit filed in federal district court in Louisiana that effectively halts the Biden Administration's suspension on new leasing. While the temporary injunction effectively allows for new leasing of oil and gas interests on federal lands and waters to resume, in August 2021, the Biden Administration appealed the Louisiana federal district court's decision to the U.S. Court of Appeals for the Fifth Circuit and the government's appeal remains pending.

In addition, BHP Petroleum has a 25% and 22% ownership interest, respectively, in the companies that own the Caesar oil pipeline and Cleopatra natural gas pipeline located in the U.S. GOM (together, the "**Offshore Pipelines**"). The Offshore Pipelines are subject to regulation by the Federal Energy Regulatory Commission ("**FERC**") pursuant to OCSLA, which includes, among other things, a duty to provide open and non-discriminatory access on the Offshore Pipeline facilities. Shippers or other entities may file a complaint claiming that the Offshore Pipelines are acting in a manner inconsistent with the open access and non-discrimination requirements of OCSLA. If FERC grants such a protest, the Offshore Pipelines may be required to modify the terms or conditions or otherwise alter their business conduct regarding the transportation services. BSEE has also adopted regulations for offshore pipelines under its jurisdictions.

The Offshore Pipelines are also subject to stringent safety laws and regulations. BHP Petroleum's transportation of crude oil and natural gas involves a risk that hazardous liquids or flammable gases may be released into the environment, potentially causing harm to the public or the environment. In turn, for owned or operated pipelines, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages, and significant business interruption. The Pipeline and Hazardous Materials Safety Administration ("**PHMSA**"), under the U.S. Department of Transportation, has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of onshore and offshore pipelines, including the Offshore Pipelines. These regulations contain requirements for the development and implementation of pipeline integrity management programmes, which include the inspection and testing of pipelines and necessary maintenance or repairs, and also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans. BSEE has also adopted regulations for offshore pipelines under its jurisdiction.

Pipeline safety laws and regulations are subject to change over time. Changes in existing laws and regulations could require us to install new or modified safety controls, conduct subsea inspection of active pipelines to detect leaks, pursue additional capital projects, or conduct maintenance programmes on an accelerated basis, any or all of which could result in BHP Petroleum incurring increased operating costs. For example, PHMSA issued the Safety of Hazardous Liquids Pipelines final rule on 1 October 2019. This final rule addressed topics such as: inspections of onshore and offshore pipelines following extreme weather events or natural disasters, periodic assessment of pipelines not currently subject to integrity management, expanded use of leak detection systems, increased use of in-line inspection tools, and other requirements. Additional rulemakings related to pipeline safety are expected to be issued in the future as in its reauthorisation of PHMSA, the U.S. Congress ordered PHMSA to move forward with certain rulemakings.

BHP Petroleum's sales of natural gas in the United States are subject to regulation by FERC. Pursuant to authority delegated to it by the Energy Policy Act of 2005 ("**EPAct 2005**"), the FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms that make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to (i) use or employ any device, scheme or artifice to defraud, (ii) make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or (iii) engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity. The EPAct 2005 also amended the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 to give FERC authority to impose civil penalties for violations of these statutes and regulations, up to US$1,307,164 per violation, per day for 2021 (this amount is adjusted annually for inflation). The FERC may also order disgorgement of profits and corrective action. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which includes annual reporting requirements for entities that purchase or sell a certain volume of natural gas in a given calendar year.

Finally, BHP Petroleum's sales of oil and natural gas are also subject to market manipulation and anti-disruptive requirements under the Commodity Exchange Act ("**CEA**") as amended by the Dodd-Frank Financial Reform Act, and regulations promulgated thereunder by the CFTC. The CFTC prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Woodside's purchase of LNG from Cheniere in the United States

In July 2014, Woodside signed a binding LNG sale and purchase agreement ("**SPA**") with a subsidiary of Cheniere Energy, Inc. ("**Cheniere**") to purchase 0.85 Mtpa of LNG from the Corpus Christi Liquefaction Project ("**CCL Project**") on the start-up of Train 2 at the LNG export facility being developed near Corpus Christi, Texas. Under the SPA, Woodside agreed to purchase LNG from Cheniere on a free-on-board basis for a term of twenty years commencing upon the date of first commercial delivery for Train 2, with an extension option of up to ten years. Cheniere completed construction of Train 2 of the CCL Project and commenced commercial operating activities in August 2019.

The *Natural Gas Act of 1938*, as amended ("**NGA**"), regulates, among others, the importation and exportation of LNG. Section 3(a) of the NGA prohibits the importation or exportation of natural gas, including LNG, from or to a foreign country without obtaining prior authorisation from the U.S. Department of Energy ("**DOE**"). Except with respect to countries with which trade is explicitly prohibited by law or policy, DOE is required to issue the authorisation unless it finds that the proposed importation or exportation is not consistent with the public interest. For authorisations to export LNG to countries with which the United States has not entered into a Free Trade Agreement ("**FTA**") requiring national treatment for trade in natural gas, DOE is able to modify the application and impose such terms and conditions as it may consider necessary or appropriate. An extensive consultation and review process is undertaken by DOE in connection with any application to import or export natural gas, including LNG.

For exportation of natural gas, including LNG, to a nation with which an FTA requiring national treatment for trade in natural gas is in effect, Section 3(c) of the NGA provides that such exportation will be deemed to be consistent with the public interest and applications for such exportation will be granted without modification or delay. DOE is statutorily required by Section 3(c) of the NGA to approve LNG exports to countries with which the United States has an FTA requiring national treatment for trade in natural gas but can restrict or limit exports to other countries if it finds the exports are not consistent with the public interest.

In addition, the importation and exportation of natural gas from and to the United States is subject to regulation and oversight by the U.S. Customs and Border Protection, the U.S. Coast Guard, the U.S. Department of Transportation and the Maritime Administration.

Part 14 – Historical Financial Information of the Merged Group

Woodside Historical Financial Information

Please refer to Annexure 1 to this Prospectus which contains the audited consolidated financial statements of the Woodside Group as derived from the annual consolidated financial statements of the Woodside Group for the financial years ended 31 December 2021, 31 December 2020 and 31 December 2019 (in each case, prepared in accordance with Australian Accounting Standards and comply with International Financial Reporting Standards as issued by the International Accounting Standards Board).

BHP Petroleum Historical Financial Information

Please refer to Annexure 2 to this Prospectus which contains the combined financial statements in respect of BHP Petroleum for (i) the half year ended 31 December 2021 (together with the half year ended 31 December 2020 for comparatives purposes) (unaudited), (ii) the financial years ended 30 June 2021 and 30 June 2020 (audited) and (iii) the financial year ended 30 June 2019 (unaudited).

Part 15 – Unaudited Pro Forma Financial Information

Section A – Unaudited Pro Forma Financial Information on the Merged Group

1. Basis of preparation

The unaudited pro forma income statement and pro forma statement of net assets (together the "**Unaudited Pro Forma Financial Information**") of the Merged Group set out below has been prepared in accordance with the requirements of Annex 20, sections 1 and 2 of the UK Prospectus Delegated Regulation.

The Unaudited Pro Forma Financial Information has been prepared to illustrate the effect of the Merger as follows:

- The unaudited pro forma income statement for the year ended 31 December 2021 has been prepared to illustrate the effect of the Merger as if the Merger had taken place on 1 January 2021; and
- The unaudited pro forma statement of net assets as at 31 December 2021 has been prepared to illustrate the effect of the Merger as if the Merger had taken place on 31 December 2021.

The Unaudited Pro Forma Financial Information has been provided for illustrative purposes only. The hypothetical financial position or results included in the Unaudited Pro Forma Financial Information are not intended to represent or be indicative of the results of operations or the financial position of the Merged Group that would have been recorded had the Merger been implemented as of the dates presented and may differ from the actual or future results of operations or financial position of the Merged Group. No account has been taken of changes in financial position or results of Woodside or BHP Petroleum after 31 December 2021.

The Unaudited Pro Forma Financial Information does not reflect the impacts of any potential operational efficiencies, asset dispositions, cost savings or economies of scale that the Merged Group may achieve with respect to the combined operations.

The Unaudited Pro Forma Financial Information has been prepared on the basis set out in the notes below and has been prepared in a manner consistent with the accounting policies that were applied by Woodside in its consolidated financial statements for the year ended 31 December 2021.

Unless specifically noted, all adjustments are expected to have continuing impact on the business.

Ernst & Young's 'Reasonable Assurance Report on the Compilation of the Unaudited Pro Forma Financial Information' is set out at Section B of this Part 15.

UNAUDITED PRO FORMA INCOME STATEMENT

FOR THE YEAR ENDED 31 DECEMBER 2021

UNAUDITED PRO FORMA INCOME STATEMENT (In US$ millions)	Woodside 31 December 2021	Adjusted BHP Petroleum 30 June 2021	Adjustments: Purchase price allocation Adjustments	Adjustments: Other Merger Adjustments	Pro Forma Merged Group 31 December
	Note 1	Note 2	Note 3	Note 4	
Operating revenue	6,962	3,909	—	—	10,871
Cost of sales	(3,845)	(2,238)	321	—	(5,762)
Gross profit	**3,117**	**1,671**	**321**	**—**	**5,109**
Other income	139	130	—	—	269
Other expenses	(811)	(1,530)	—	(410)	(2,751)
Impairment losses	(10)	(127)	—	—	(137)
Impairment reversals	1,058	—	—	—	1,058
Loss from equity accounted investments	—	(6)	—	—	(6)
Profit before tax and net finance costs	**3,493**	**138**	**321**	**(410)**	**3,542**
Finance income	27	56	—	—	83
Finance costs	(230)	(464)	—	—	(694)
Profit/(loss) before tax	**3,290**	**(270)**	**321**	**(410)**	**2,931**
Petroleum resource rent tax expense	(297)	—	—	—	(297)
Income tax expense	(957)	(187)	(80)	123	(1,101)
Royalty – related taxation (net of income tax benefit)	—	24	—	—	24
Profit/(loss) after tax	**2,036**	**(433)**	**241**	**(287)**	**1,557**
Profit/(loss) attributable to:					
Equity holders of the parent	1,983	(433)	241	(287)	1,504
Non-controlling interest	53	—	—	—	53
Profit/(loss) for the period	**2,036**	**(433)**	**241**	**(287)**	**1,557**

NOTE 1. WOODSIDE

The consolidated income statement of Woodside for the year ended 31 December 2021 has been extracted without material adjustment from the audited consolidated financial statements of Woodside for the year ended 31 December 2021, which comply with IFRS and are included in Annexure 1 of this document.

NOTE 2. BHP PETROLEUM

The combined income statement of BHP Petroleum for the financial year ended 30 June 2021 has been extracted without material adjustment from the historical financial information of BHP Petroleum for the financial year ended 30 June 2021, which has been prepared in accordance with IFRS, and included in Annexure 2 of this document and has been adjusted to Woodside's presentation and accounting treatment. A reconciliation of BHP Petroleum's unaudited Income Statement to Woodside's presentation is presented below:

Reconciliation at 30 June 2021 (unaudited)	BHP Petroleum Income Statement 30 June 2021 US$m	Adjustment to conform to Woodside presentation and accounting treatment US$m	BHP Petroleum Income Statement Woodside presentation US$m
		Note 2(a)(b)	
Operating revenue	3,909	—	3,909
Cost of sales	—	(2,238)	(2,238)
Gross profit	**3,909**	**(2,238)**	**1,671**
Other income	130		130
Other expenses	(3,799)	2,269	(1,530)
Impairment losses	—	(127)	(127)
Impairment reversals	—	—	—
Loss from equity accounted investments	(6)	—	(6)

Reconciliation at 30 June 2021 (unaudited)	BHP Petroleum Income Statement 30 June 2021 US$m	Adjustment to conform to Woodside presentation and accounting treatment US$m	BHP Petroleum Income Statement Woodside presentation US$m
		Note 2(a)(b)	
Profit/(loss) before tax and net finance costs	**234**	**(96)**	**138**
Finance income	56	—	56
Finance costs	(464)	—	(464)
Loss before tax	**(174)**	**(96)**	**(270)**
Petroleum resource rent tax (expense)/benefit	—	—	—
Income tax benefit/(expense)	(211)	24	(187)
Royalty–related taxation (net of income tax benefit)	24	—	24
Loss after tax	**(361)**	**(72)**	**(433)**
Loss attributable to:			
Equity holders of the parent	(361)	(72)	(433)
Non-controlling interest	—	—	—
Loss for the period	**(361)**	**(72)**	**(433)**

2(a) *Cost of Sales*

Cost of sales includes a reclassification adjustment of US$2,142 million from other expenses. Costs relating to changes in inventory, freight and transportation, government royalties, depreciation and amortisation are classified by Woodside as cost of sales.

In addition to the reclassification of US$2,142 million described above, cost of sales is:

- Increased by US$154 million to reflect an adjustment to conform BHP Petroleum's accounting treatment for overlift and underlift to Woodside's accounting treatment. Specifically, Woodside's accounting treatment is to not account for the effects of volumetric imbalances.
- Decreased by US$58 million to reflect an adjustment to reverse BHP Petroleum's fair value gains on derivatives.

Other expenses/impairment losses

Other expenses of US$2,269 million have been reclassified to cost of sales (US$2,142 million) and impairment losses (US$127 million) to conform to Woodside presentation.

2(b) The adjustment to tax benefit of US$24 million reflects the tax impact of the accounting treatment adjustments to cost of sales of US$96 million as described in 2(a) above at a blended tax rate of 25% (Australian tax rate of 30% and US tax rate of 21%).

NOTE 3. PURCHASE PRICE ALLOCATION ADJUSTMENTS

Based on initial information, Woodside has performed a preliminary Purchase Price Allocation ("**PPA**") exercise. Consequently, the provisional fair value of the identifiable assets and liabilities of 31 December 2021 are shown in the table presented as part of the footnote to the pro forma statement of net assets. These assets and liabilities may be materially different as at the date when the Merger is completed. Refer statement of net assets Note 3 for further background.

The following adjustments have been made as a result of the preliminary PPA:

3(a) The adjustment to cost of sales of US$321 million reflects a decrease in pro forma depreciation, depletion, and amortisation charges ("**DD&A**") expense based on the preliminary PPA.

The depreciation of oil and gas properties includes a combination of straight line and units of production ("**UOP**") methods. Transferred exploration and evaluation, and offshore plant and equipment are depreciated using the UOP basis. Transferred exploration and evaluation and subsurface development expenditure are depreciated over developed proved plus probable reserves or proved reserves. Late life assets are typically depreciated over proved reserves. Offshore facility assets are depreciated over proved plus a portion of probable reserves. The depreciable amount for the unit of production basis for offshore facility assets excludes future development costs necessary to bring probable reserves into production. Onshore plant and equipment is depreciated using a straight-line basis over the lesser of useful life and the life of proved plus probable reserves. DD&A expense for the other property and equipment was based on a straight-line method over the estimated useful lives of the asset. BHP Petroleum's use of the proved reserve (1P) as a reserve base to determine UOP depreciation, when compared to Woodside's use of proved and probable reserves (2P) as a reserve base in UOP calculation, resulted in higher DD&A expenses recorded historically. An adjustment to conform BHP Petroleum's accounting policy to Woodside's accounting policy method resulted in a decrease of US$321 million in DD&A expense due to different reserves bases being used in the respective UOP calculations.

3(b) The adjustment to tax expense of US$80 million reflects the tax impact of the DD&A adjustment as described in 3(a) above at a blended tax rate of 25% (Australian tax rate of 30% and US tax rate of 21%). As the tax rates used for the Unaudited Pro-Forma Financial Information are an estimate, the blended rate will likely vary from the actual effective rate in periods subsequent to Implementation.

NOTE 4. OTHER MERGER ADJUSTMENTS

The following other merger adjustments have been made:

4(a) The adjustment to other expenses of US$410 million represents estimated non-recurring transaction costs in connection with the Merger (excluding integration costs), including stamp duty, advisory, legal, regulatory, accounting, valuation and other fees that are not capitalised as part of the Merger.

4(b) The adjustment to tax benefit of US$123 million reflects the tax impact of 4(a) above at Australian tax rate of 30%. As the tax rates used for the Unaudited Pro Forma Financial Information are an estimate, these rates will likely vary from the actual effective rate in periods subsequent to Implementation.

UNAUDITED PRO FORMA STATEMENT OF NET ASSETS

AS AT 31 DECEMBER 2021

UNAUDITED PRO FORMA STATEMENT OF NET ASSETS (In US$ millions)	Woodside 31 December 2021	Adjusted BHP Petroleum 31 December 2021	Adjustments: Purchase price allocation Adjustments	Adjustments: Other Merger Adjustments	Pro Forma Merged Group 31 December 2021
	Note 1	Note 2	Note 3	Note 4	
Current assets					
Cash and cash equivalents	3,025	992	—	—	4,017
Receivables	368	658	—	—	1,026
Inventories	202	278	—	—	480
Intercompany	—	10,852	—	(10,852)	—
Current tax assets	—	69	—	—	69
Other financial assets	320	—	—	—	320
Other assets	109	14	537	—	660
Non-current assets held for sale	254	—		—	254
Total current assets	**4,278**	**12,863**	**537**	**(10,852)**	**6,826**
Non-current assets					
Receivables	686	201	—	—	887
Inventories	19	—	—	—	19
Other financial assets	107	37	(37)	—	107
Other assets	34	3	—	—	37
Exploration and evaluation assets	614	941	1,964	—	3,519
Oil and gas properties	18,434	10,224	9,536	—	38,194
Other plant and equipment	215	—	—	—	215
Intangible assets	—	—	—	—	—
Deferred tax assets	1,007	1,947	(849)	—	2,105
Lease assets	1,080	124	68	—	1,272
Investments accounted for using the equity method	—	246	—	—	246
Goodwill	—	—	7,126	—	7,126
Total non-current assets	**22,196**	**13,723**	**17,808**	**—**	**53,727**
Total assets	**26,474**	**26,586**	**18,345**	**(10,852)**	**60,553**
Current liabilities					
Payables	639	914	—	1,357	2,910
Interest-bearing liabilities	277	—	—	—	277
Lease liabilities	191	38	—	—	229
Other financial liabilities	411	60	(60)	—	411
Other liabilities	86	16	—	—	102
Provisions	605	360	(16)	—	949
Tax payable	413	312	—	—	725
Intercompany payables	—	12,552	—	(12,552)	—
Total current liabilities	**2,622**	**14,252**	**(76)**	**(11,195)**	**5,603**
Non-current liabilities					
Trade and other payables – intercompany	—	—	—	—	—
Interest-bearing liabilities	5,153	—	—	—	5,153
Lease liabilities	1,176	219	—	—	1,395
Deferred tax liabilities	878	465	1,933	—	3,276
Other financial liabilities	161	—	—	—	161
Other liabilities	36	40	1,144	—	1,220
Provisions	2,219	4,101	841	—	7,161
Tax payable	—	69	—	—	69
Total non-current liabilities	**9,623**	**4,894**	**3,918**	**—**	**18,435**
Total liabilities	**12,245**	**19,146**	**3,842**	**(11,195)**	**24,038**
Net assets	**14,229**	**7,440**	**14,503**	**343**	**36,515**

NOTE 1. WOODSIDE

The net assets of Woodside as at 31 December 2021 have been extracted without material adjustment from the audited consolidated financial statements of Woodside for the year ended 31 December 2021, which comply with IFRS and are included in Annexure 1 of this document.

NOTE 2. BHP PETROLEUM

The net assets of BHP Petroleum as at 31 December 2021 have been extracted without material adjustment from the historical financial information of BHP Petroleum for the half year ended 31 December 2021, which has been prepared in accordance with IFRS, and included in Annexure 2 of this document, and has been adjusted to Woodside's presentation and accounting treatment.

Reconciliation at 31 December 2021 (unaudited)	BHP Petroleum Statement of Net Assets 31 December 2021 US$m	Adjustment to conform to Woodside presentation and accounting treatment US$m	BHP Petroleum Statement of Net Assets under Woodside presentation US$m
		Note 2(a) to 2(c)	
Current assets			
Cash and cash equivalents	992	—	992
Receivables	1,230	(572)	658
Inventories	278	—	278
Intercompany	10,852	—	10,852
Current tax assets	69	—	69
Other assets	14	—	14
Total current assets	**13,435**	**(572)**	**12,863**
Non-current assets			
Receivables	201	—	201
Other financial assets	37	—	37
Other assets	3	—	3
Exploration and evaluation assets	—	941	941
Oil and gas properties	11,102	(878)	10,224
Intangible assets	63	(63)	—
Deferred tax assets	1,947	—	1,947
Lease assets	124	—	124
Investments accounted for using the equity method	246	—	246
Total non-current assets	**13,723**	**—**	**13,723**
Total assets	**27,158**	**(572)**	**26,586**
Current liabilities			
Payables	952	(38)	914
Interest-bearing liabilities	38	(38)	—
Lease liabilities	—	38	38
Other financial liabilities	60	—	60
Other liabilities	16	—	16
Provisions	360	—	360
Tax payable	312	—	312
Intercompany payables	12,552	—	12,552
Total current liabilities	**14,290**	**(38)**	**14,252**
Non-current liabilities			
Interest-bearing liabilities	219	(219)	—
Lease liabilities	—	219	219
Deferred tax liabilities	465	—	465
Other liabilities	40	—	40
Provisions	4,101	—	4,101
Tax payable	69	—	69
Total non-current liabilities	**4,894**	**—**	**4,894**
Total liabilities	**19,184**	**(38)**	**19,146**
Net assets	**7,974**	**(534)**	**7,440**

The following reclassifications and accounting treatment adjustments have been made to the historical presentation of net assets of BHP Petroleum to conform to the financial statements presentation and accounting treatment of Woodside.

2(a) The adjustments to 'receivables' (US$572 million) and 'payables' (US$38 million) reflect adjustments to conform BHP Petroleum's accounting treatment for underlift and overlift to Woodside's accounting treatment. Specifically, Woodside's accounting treatment is to not account for the effects of volumetric imbalances.

2(b) Reclassification adjustments have been made to the historical presentation of BHP Petroleum's intangible assets (US$63 million) and oil and gas properties (US$878 million) to conform to the financial statement presentation of Woodside. These balances have been reclassified to 'exploration and evaluation assets' (US$941 million).

2(c) Reclassification adjustments have been made to the historical presentation of BHP Petroleum's current interest-bearing liabilities (US$38 million) and non-current interest-bearing liabilities (US$219 million) to conform to the financial statement presentation of Woodside. These balances have been reclassified to 'lease liabilities'.

NOTE 3. PURCHASE PRICE

Certain transaction accounting adjustments have been made in order to show the effects of the Merger on the Woodside Historical Financial Information, by applying the acquisition method of accounting under IFRS 3 *Business Combinations*.

The Merger will be accounted for using the acquisition method of accounting for business combinations. The allocation of the preliminary estimated purchase price is based upon Woodside management's estimates of and assumptions related to the fair value of assets to be acquired and liabilities to be assumed at 31 December 2021. Because the Unaudited Pro Forma Financial Information has been prepared prior to Implementation, it is based on these preliminary estimates, the final purchase price allocation and the resulting effect on Woodside's financial position and results of operations may materially differ from the pro forma adjustment amounts included in this prospectus. Woodside has finalised its preliminary assessment of the fair values as at the Implementation Date of the Merger of certain identifiable intangible assets. There are number of items that can materially change the fair value of the identifiable intangible assets and goodwill as noted below.

The preliminary PPA is subject to change as a result of several factors, including but not limited to:

- the fair value of the Share Consideration has been determined using the share price as at 24 March 2022 and will be subject to change up until the Implementation of the Merger, which will have an impact on the total purchase consideration for the acquisition and goodwill recognised;
- further commercially sensitive and proprietary information about BHP Petroleum will only become available after the Implementation of the Merger which may materially change the fair values of the identifiable intangible assets;
- external and internal factors that influence the fair value of the identifiable intangible may change up until the Implementation of the Merger which may materially change the fair values of the identifiable intangible assets from what is disclosed;
- the tax basis of BHP Petroleum's assets and liabilities; and
- certain of the risk factors described in the section entitled "*Risk Factors*", including but not limited to, fluctuations in LNG market conditions and the price of crude oil; exposure to short term contracts and spot pricing; commodity and currency hedging; risks with oil and gas exploration, development and production activities; financing; estimated petroleum reserves that may not materialise; regulatory permits and approvals; litigation or arbitration risks; government and sovereign risks; fluctuations in exchange rates; tax consequences; and impairments of goodwill and assets.

The estimated Purchase Price reflects:

- the recognition of estimated equity consideration of US$22,696 million on the issuance of the New Woodside Shares;
- the recognition of cash consideration of US$830 million on Woodside Dividend Payment; and
- US$117 million estimated Locked Box Payment payable by Woodside to BHP which is calculated by reference to cash held in bank accounts beneficially controlled by BHP Petroleum as at 31 December 2021 of US$ 992 million and subtracting Woodside's current expectations of net cash flows of BHP Petroleum

(adjusted for permitted adjustments) for the period from 1 July 2021 to 31 December 2021 of approximately US$875 million.

The estimated purchase price for BHP Petroleum is based on the ASX closing price of the Woodside Shares on 24 March 2022. The requirement to base the final purchase price on the share price as of the Implementation could result in a purchase price that is materially different from that assumed in the Unaudited Pro Forma Financial Information, and the purchase price included in this document should not be taken to represent what the actual consideration transferred will be on the Implementation Date.

The following table summarises the components of the estimated consideration:

New Woodside Shares to be issued (in thousands)	914,769
ASX closing price per share of Woodside Shares on 24 March 2022 (in A$)	33.20
Foreign exchange rate used on conversion of AUD Woodside Shares to USD as at 24 March 2022	0.7473
Fair value of New Woodside Shares to be issued as consideration (in US$ millions)	22,696
Estimated Dividend consideration (in US$ millions)	830
Estimated Locked box consideration (in US$ millions)	117
Total consideration (in US$ millions)	23,643

Based on initial information, Woodside has performed a preliminary PPA exercise. The provisional fair value of the identifiable assets and liabilities of BHP Petroleum are shown in the table below.

Net identifiable assets of BHP Petroleum	**BHP Petroleum Balance Sheet under Woodside presentation US$m**	**Adjustments US$m**	**Note**	**Fair value of Assets and Liabilities assumed US$m**
Cash	992	—		992
Receivables	859	—		859
Inventories	278	—		278
Intercompany	10,852	(10,852)	4(a)	—
Other financial assets	37	(37)	3(b)	—
Other assets	17	537	3(c)	554
Current tax assets	69	—		69
Exploration and evaluation assets	941	1,964	3(d)	2,905
Oil and gas properties	10,224	9,536	3(d)	19,760
Deferred tax assets	1,947	(849)	3(e)	1,098
Lease assets	124	68	3(f)	192
Investments accounted for using the equity method	246	—		246
Total assets acquired	**26,586**	**367**		**26,953**
Payables	914	—		914
Lease liabilities	257	—		257
Other financial liabilities	60	(60)	3(b)	—
Deferred tax liabilities	465	1,933	3(e)	2,398
Other liabilities	56	1,144	3(h)	1,200
Intercompany payables	12,552	(12,552)	4(a)	—
Tax payable	381	—		381
Provisions	4,461	825	3(g)	5,286
Total liabilities acquired	**19,146**	**(8,710)**		**10,436**
Total assets and liabilities acquired				**16,517**
Goodwill			3(i)	7,126

3(a) From 16 August 2021, the last trading day before the announcement of the Merger Commitment Deed, to 24 March 2022, the preliminary value of BHP Petroleum's Purchase Price increased by approximately $9,722 million, as a result of the increase in the share price of Woodside Shares from A$21.18 to A$33.20 and movement in the foreign exchange rate from AUD to USD from $0.7336 to $0.7473 in addition to movements in the expected number of New Woodside Shares to be issued, Woodside Dividend payment and estimated Locked Box Payment. The final value of Woodside's Purchase Price will be determined based on the actual number of New Woodside Shares issued to BHP and issuable in connection with the conversion or settlement of BHP Petroleum's equity awards, and the market price of Woodside Shares on the Implementation Date. A 10% increase or decrease in the closing share price of Woodside Shares, as compared to the 24 March 2022 closing price of A$33.20, would increase or decrease the Purchase Price by approximately US$2,270 million, assuming all other factors are held constant.

3(b) Reflects a preliminary PPA adjustment to BHP Petroleum's other financial assets (US$37 million) and other financial liabilities (US$60 million) in respect of embedded derivatives.

3(c) Reflects adjustment to other assets (US$537 million) in respect of entitlement to additional LNG volumes.

3(d) Reflects a preliminary PPA adjustment resulting in an increase to BHP Petroleum's oil and gas properties (US$9,536 million) and exploration and evaluation assets (US$1,964 million).

3(e) Reflects an adjustment to deferred tax asset (US$849 million) and deferred tax liabilities (US$1,933 million) to record the estimated deferred income tax effects of combining Woodside's and BHP Petroleum's operations, as well as changes to the deferred tax amounts as a result of the preliminary PPA. The deferred tax adjustment assumes a forecasted blended BHP Petroleum statutory tax rate of 30.0%. The pro forma income tax adjustments included in the pro forma income statement for the year ended 31 December 2021 reflect the income tax effects of the transaction accounting adjustments presented including Petroleum Rent Resource Tax. Because the tax rates used for the Unaudited Pro Forma Financial Information are an estimate, the blended rate will likely vary from the actual effective rate in periods subsequent to Implementation.

3(f) Reflects a preliminary PPA adjustment to BHP Petroleum's right-of-use assets (US$68 million).

3(g) Primarily reflects a preliminary PPA adjustment of US$825 million to record the estimated fair value of the assumed BHP Petroleum asset retirement obligations. As part of the preliminary PPA, Woodside estimated the timing and amount of the closure and rehabilitation cash flows expected to be incurred. As a result, the current provision is decreased by US$16 million, and the non-current provision is increased by US$841 million. To establish the value of the provision for the Merged Group, in respect of BHP Petroleum's assets, Woodside has adopted BHP Petroleum's cost estimates and schedule, and it has applied Woodside's escalation and discount rate assumptions.

3(h) Adjustments have been made to other liabilities in respect of additional liabilities assumed (US$56 million) and unfavourable contracts primarily relating to the fair value of a long term fixed price LNG contract (US$1,088 million).

3(i) Represents the goodwill arising from the preliminary PPA adjustment, which represents the excess of the estimated purchase consideration over the estimated fair value of the identifiable assets and liabilities in BHP Petroleum.

The preliminary Purchase Price allocation has been prepared on the basis of the Woodside Share price and the AUD/USD exchange rate as at 24 March 2022, and a fair value based on forward-looking prices as at 24 March 2022. Commodity market forward curves have been utilised for the period 2022 to 2026 in determining the forward-looking prices in this Unaudited Pro Forma Financial Information. The use of forward curve pricing assumptions reflect current market conditions and the limited availability of independent published price forecasts.

NOTE 4. OTHER MERGER ADJUSTMENTS

Other merger adjustments are made to the unaudited pro forma statement of net assets

4(a) The adjustments to current intercompany receivables (US$10,852 million), current intercompany payables (US$12,552 million) reflect the Merger being on a cash-free debt-free basis where BHP Petroleum will settle all intercompany loan balances prior to Implementation.

4(b) The adjustment to current payables of US$1,357 million primarily relates to non-recurring transaction costs of approximately US$410 million that are expected to be incurred by Woodside and BHP Petroleum, including stamp duty, advisory, legal, regulatory, accounting, valuation and other fees that are not capitalised as part of the Merger are shown as an expense adjustment of US$410 million in the pro forma income statement. The cash considerations payable relate to the Woodside Dividend Payment of US$830 million and the estimated Locked Box Payment (which is net of any cash held in bank accounts beneficially controlled by BHP Petroleum upon Implementation) of US$117 million[55]. These transaction costs are based on preliminary estimates and the final amounts and the resulting effect on the Merged Group's financial position and results of operations may differ.

[55] The estimated Locked Box Payment has been calculated by reference to the cash held in bank accounts beneficially controlled by BHP Petroleum as at 31 December 2021 of $992 million and subtracting Woodside's current expectations of net cash flows of BHP Petroleum (adjusted for permitted adjustments) for the period 1 July 2021 to 31 December 2021 of approximately US$875 million.

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The Directors
Woodside Petroleum Ltd
Mia Yellagonga
11 Mount Street
Perth WA 6000
Australia

11 April 2022

Dear Directors

Woodside Petroleum Ltd ("Woodside")

Independent assurance report on the compilation of Unaudited Pro Forma Financial Information included in the prospectus

We have completed our reasonable assurance engagement to report on the compilation of unaudited pro forma financial information of the Merged Group by the directors of Woodside. The unaudited pro forma financial information consists of the unaudited pro forma income statement for the year ended 31 December 2021, the unaudited pro forma statement of net assets as at 31 December 2021 and related notes (the "Unaudited Pro Forma Financial Information"), as set out in Section A of Part 15 (Unaudited Pro Forma Financial Information) of the prospectus dated 11 April 2022 (the "Prospectus").

This report is required by Section 3 of Annex 20 of the UK version of Commission Delegated Regulation (EU) 2019/980 ("the UK Prospectus Delegated Regulation") and is given for the purpose of complying with that section and for no other purpose.

For the purposes of this letter, the "Merged Group" consists of Woodside and the entities it controlled during the year ended 31 December 2021 (the "Woodside Group") and BHP Petroleum International Pty Ltd and its subsidiaries presented on a post Restructure basis ("BHP Petroleum"). Unless otherwise defined in this report or the context otherwise requires, expressions and terms defined in the Prospectus have the same meaning in this report.

The Unaudited Pro Forma Financial Information has been compiled by the directors of Woodside to illustrate the effect of the Merger on the Woodside Group's consolidated financial position as at 31 December 2021 and its consolidated financial performance for the year ended 31 December 2021 as if the Merger had taken place at 31 December 2021 and 1 January 2021, respectively.

As part of this process, information about the Woodside Group's consolidated financial position and consolidated financial performance has been extracted from Woodside's consolidated financial statements for the year ended 31 December 2021, on which an audit report has been published, BHP Petroleum's combined financial statements for the year ended 30 June 2021, on which an audit report has been published, and BHP Petroleum's combined financial statements for the half year ended 31 December 2021, on which a review opinion has been published.

The directors' responsibility for the Unaudited Pro Forma Financial Information

The directors of Woodside are responsible for properly compiling the Unaudited Pro Forma Financial Information in accordance with Sections 1 and 2 of Annex 20 of the UK Prospectus Delegated Regulation.

Our Independence and quality control

We have complied with relevant ethical requirements related to assurance engagements, which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality, and professional behaviour.

The firm applies Australian Standard on Quality Control 1 and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with relevant ethical requirements and applicable legal and regulatory requirements.

Our responsibilities

Our responsibility is to express an opinion about whether the Unaudited Pro Forma Financial Information has been properly compiled by the directors of Woodside, as required by Section 3 of Annex 20 of the UK Prospectus Delegated Regulation.

Save for any responsibility arising under Prospectus Regulation Rule 5.3.2R (2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with item 1.3 of Annex 1 to the UK Prospectus Delegated Regulation, consenting to its inclusion in the Prospectus.

Basis of opinion

We conducted our engagement in accordance with Standard on Assurance Engagements ASAE 3420, *Assurance Engagements To Report on the Compilation of Pro Forma Historical Financial Information included in a Prospectus or other Document* (ASAE 3420), issued by the Auditing and Assurance Standards Board of Australia. This standard requires that the assurance practitioner plan and perform procedures to obtain reasonable assurance about whether the directors of Woodside have compiled the Unaudited Pro Forma Financial Information in accordance with Sections 1 and 2 of Annex 20 of the UK Prospectus Delegated Regulation.

For purposes of this engagement, we are not responsible for updating or reissuing any reports or opinions on any historical financial information used in compiling the Unaudited Pro Forma Financial Information, nor have we, in the course of this engagement, performed an audit or review of the historical financial information used in compiling the Unaudited Pro Forma Financial Information, or of the Unaudited Pro Forma Financial Information itself.

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The purpose of pro forma financial information being included in a prospectus is solely to illustrate the impact of a significant event(s) or transaction(s) on unadjusted financial information of the Merged Group as if the event(s) had occurred or the transaction(s) had been undertaken at an earlier date selected for purposes of the illustration. Accordingly, we do not provide any assurance that the actual outcome of the event(s) or transaction(s) at 31 December 2021 would have been as presented.

A reasonable assurance engagement to report on whether the Unaudited Pro Forma Financial Information has been compiled, on the basis of the applicable criteria, involves performing procedures to assess whether the applicable criteria used by the directors of Woodside in the compilation of the Unaudited Pro Forma Financial Information provide a reasonable basis for presenting the significant effects directly attributable to the event(s) or transaction(s), and to obtain sufficient appropriate evidence about whether:

- The related pro forma adjustments give appropriate effect to those criteria; and
- The Unaudited Pro Forma Financial Information reflects the proper application of those adjustments to the unadjusted financial information.

The procedures selected depend on the assurance practitioner's professional judgement, having regard to the assurance practitioner's understanding of the nature of the Merged Group, the event(s) or transaction(s) in respect of which the Unaudited Pro Forma Financial Information has been compiled, and other relevant engagement circumstances.

The engagement also involves evaluating the overall presentation of the Unaudited Pro Forma Financial Information.

We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion:

- The Unaudited Pro Forma Financial Information has been properly compiled on the basis stated; and
- Such basis is consistent with the accounting policies of Woodside.

Consent

Ernst & Young has given and not withdrawn its written consent to the inclusion of this report in the Prospectus.

Declaration of independence

Ernst & Young does not have any interest in the outcome of the Merger other than in providing this report for which normal professional fees will be received.

Declaration

For the purposes of Prospectus Regulation Rule 5.3.2R (2)(f) we are responsible for this report as part of the Prospectus and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that the report contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 1 of the UK Prospectus Delegated Regulation.

Yours faithfully

Ernst & Young

Ernst & Young

Part 16 – Capitalisation and Indebtedness

The following table shows the consolidated gross indebtedness of the Woodside Group as at 28 February 2022 as if Implementation had not occurred. The indebtedness and capitalisation figures have been extracted from the underlying accounting records of the Woodside Group as at 28 February 2022 without adjustment and are unaudited.

For an illustrative analysis of the effect of the Merger on the Merged Group's income statement and statement of net assets (after making certain pro forma adjustments), please see Part 15 (*Unaudited Pro Forma Financial Information*).

Indebtedness

	US$m
Total Current Debt	470
Guaranteed	193
Secured	277
Unguaranteed/Unsecured	—
Total Non-Current Debt	6,255
Guaranteed	5,069
Secured	1,186
Unguaranteed/Unsecured	—

Capitalisation

	US$m
Issued capital	9,409
Reserves	3,015
Total issued capital and reserves	12,424

Reserves includes foreign currency translation reserves, the share-based payment reserve in respect of share option and performance rights schemes, and other reserves (excluding retained earnings).

The following table shows the Woodside Group's net indebtedness as at 28 February 2022

	US$m
Liquidity (Cash and cash equivalents (unrestricted))	3,422
Current Financial Receivable	—
Current Bank debt	235
Current portion of non-current debt	—
Other current financial debt	194
Current Financial Debt	428
Net Current Financial Indebtedness	(2,994)
Non-current bank loans	1,070
Bonds Issued	4,083
Other non current loans	1,145
Non-current Financial Indebtedness	6,297
Net Financial Indebtedness	3,303

As at 28 February 2022 the Woodside Group had no material indirect or contingent indebtedness.

Part 17 – Operating and Financial Review of Woodside

The following Operating Financial Review is a review of the operations and current financial position for the years ended 31 December 2021, 2020 and 2019. The following should be read in conjunction with Woodside's audited consolidated financial statements and the notes thereto included elsewhere in this Prospectus. The following discussion and analysis contain forward-looking statements. See "Part 2 (*Risk Factors*)" and Part 3 *(Presentation of Financial Information and Other Information)* of this Prospectus for a discussion of the uncertainties, risks and assumptions associated with these statements.

Basis of Presentation

Woodside's audited consolidated financial statements included in Annex 1 of Part 24 (*Annexures)* comply with IFRS. The financial statements have been prepared on a historical cost basis, except for derivative financial instruments and certain other financial assets and financial liabilities, which have been measured at fair value or amortised cost adjusted for changes in fair value attributable to the risks that are being hedged in effective hedge relationships.

Frequently Recurring Terms

Woodside uses the following frequently recurring terms in this OFR: "**WTI**" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States; "**bbl**" refers to barrel; "**NGL**" refers to Natural gas liquids; "**MCF**" refers to thousand cubic feet; and "**boe**" refers to barrels of oil equivalent. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion ratio of 5.7 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead; "**OPEC**" known as Organization of the Petroleum Exporting Countries, refers to a group of 13 of the world's major oil-exporting nations, and "**OPEC+**" refers to the group of 13 members and 10 of the world's major non-OPEC oil-exporting nations.

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The following discussion and analysis is intended to provide investors with an understanding of the historical performance of Woodside and its financial condition. This discussion and analysis present the factors that had a material effect on the results of operations of Woodside for the fiscal years ended 31 December 2021, 2020 and 2019.

1 Business overview

Woodside is an independent integrated upstream supplier of energy. The Company is Australia's largest independent oil and gas exploration and production operator by market capitalisation (as at 31 December 2021) and a major supplier of energy to the Asia-Pacific region. Woodside maintains a strong focus on operational excellence by pursuing safe, reliable, and cost-effective operations.

Woodside's vision and mission is to deliver affordable energy solutions and superior outcomes for stakeholders. To achieve this over the long term, Woodside is focused on maximising cash generation from its base business and executing a range of development projects over the medium term. Woodside seeks to build its portfolio through disciplined capital allocation, which will seek to prioritise lower capital intensity, faster to market, capital efficient investments that utilise existing infrastructure where possible.

Woodside's operated LNG projects include two integrated projects, the NWS Project (Australia's largest LNG project) and Pluto LNG. In 2020, Woodside's operating performance was demonstrated by the reduction in unit production costs down to their lowest level in 5 years at US$4.8/boe while achieving LNG reliability of 97.6%.

Offshore, Woodside operates two floating production storage and offloading ("**FPSO**") facilities, the Okha FPSO and Ngujima-Yin FPSO. Woodside also has a participating interest in Wheatstone LNG, which started production in 2017 and is the upstream operator for the Wheatstone LNG feeder fields, Julimar-Brunello.

In addition to their producing assets Woodside is developing the Scarborough gas resource through new offshore facilities to a second LNG train (Pluto Train 2) at the existing Pluto LNG onshore facility in Western Australia. Woodside is also connecting Pluto LNG with the North West Shelf Project through the Pluto-KGP Interconnector to create an integrated LNG production hub on the Burrup Peninsula. Internationally, Woodside is executing the Sangomar Field Development Phase 1 in Senegal, having achieved final investment decision in January 2020. This development is targeting first oil in 2023.

Woodside's Australian operations are in the North West Shelf and the Burrup Peninsula of Western Australia. Domestic gas is sold to customers in Western Australia. LNG, LPG, condensate, and oil are sold to customers primarily in Asia. Woodside's financial condition, operating cash flows and results of operations are driven by several factors, including:

- Oil and gas prices
- Currency fluctuations
- Capital and exploration expenditure

On 22 November 2021, Woodside and BHP announced that they had entered into a binding Share Sale Agreement to implement the Merger. The Merger is summarised below in paragraph 1 of this Part 17 (*Operating and Financial Review of Woodside)* of this Prospectus.

The following table presents Woodside's production volumes, realised prices and financial highlights for the years ended 31 December 2021, 2020 and 2019:

	Units	2021	2020	2019
Production Volumes				
LNG	MMboe	70.8	75.1	67.7
Domestic gas	MMboe	2.5	5.3	6.1
Condensate	MMboe	8.7	9.8	9.6
Oil	MMboe	8.6	9.7	5.6
LPG	MMboe	0.5	0.5	0.5
Total production	**MMboe**	**91.1**	**100.3**	**89.6**
Average Realised Sales Price				
Average realised price	US$/boe	**60.3**	32.4	47.8
Financial Data				
Operating revenue	US$m	6,962	3,600	4,873
Profit / (loss) after tax	US$m	1,983	(4.028)	343

Profit after tax for the year ended 31 December 2021 increased by US$6,011 million compared to the year ended 31 December 2020, primarily due to higher realised Brent, JCC and JKM commodity prices and impairment reversals which were recognised on oil and gas properties.

Profit after tax for the year ended 31 December 2020 decreased by US$4,357 million compared to the year ended 31 December 2019, primarily due to lower realised Brent, JCC and JKM commodity prices and impairments which were recognised on oil and gas properties and exploration and evaluation assets driven by a reduction in oil and gas price assumptions, increased longer-term demand uncertainty and other factors including increased risk of higher carbon pricing. This decrease in profit after tax due to commodity price and impairments was partially offset by higher production volumes.

Recent business acquisitions and divestments

On 15 November 2021, Woodside entered into a sale and purchase agreement with GIP for the sale of a 49% non-operating participating interest in the Pluto Train 2 Joint Venture. Pluto Train 2 is a key component of the Scarborough development and includes a new LNG train and domestic gas facilities to be constructed at the existing Pluto LNG onshore facility. The development of Pluto Train 2 is supported by a long-term Processing and Services Agreement ("**PSA**") between the Pluto Train 2 and Scarborough joint ventures. The transaction completed on 18 January 2022, reducing the Group's participating interest from 100% to 51%. Accordingly, the associated Pluto Train 2 assets within the Development segment have been reclassified to non-current assets held for sale. The arrangements require GIP to fund its 49% share of capital expenditure from 1 October 2021 and an additional amount of capital expenditure of approximately US$822 million. If the total capital expenditure incurred is less than US$5,600 million, GIP will pay Woodside an additional amount equal to 49% of the under-spend. In the event of a cost overrun, Woodside will fund up to approximately US$822 million of GIP's share of the overrun. Delays to the expected start-up of production will result in payments by Woodside to GIP in certain circumstances. The arrangements include provisions for GIP to be compensated for exposure to additional Scope 1 emissions liabilities above agreed baselines, and to sell its 49% interest back to Woodside if the status of key regulatory approvals materially changes.

On 22 November 2021, Woodside and BHP announced that they had entered into a binding Share Sale Agreement to implement the Merger.

Pursuant to the Share Sale Agreement, Woodside will acquire the entire share capital of BHP Petroleum International Pty Ltd in exchange for New Woodside Shares. The signing of the Share Sale Agreement follows the Merger Commitment Deed announced on 17 August 2021. Completion is targeted for Q2 2022. On completion of the Merger, Woodside will issue new shares comprising approximately 48% of all Woodside Shares (on a post-issue basis) as consideration for the acquisition of BHP Petroleum. The New Woodside shares will be distributed indirectly to Eligible BHP Shareholders. Prior to completion, Woodside and BHP will carry on their respective businesses in the normal course and will work closely to ensure a smooth transition of ownership. The effective time of the Merger will be 11:59pm on 30 June 2021. Completion of the Merger is subject to satisfaction (or waiver where permitted) of conditions precedent by 30 June 2022 or an agreed later date (see paragraph 6 of Part 10 *(Summary of the Merger)* of this Prospectus.

On 7 July 2021, Woodside Energy (Senegal) B.V. completed the acquisition of the entire participating interest of FAR Senegal RSSD S.A. in the RSSD joint venture. The purchase price was US$45 million plus a working capital adjustment of approximately US$167 million to reflect the acquisition effective date of 1 January 2020. The final completion payment to FAR Senegal RSSD S.A., after adjustments and remedying of FAR Senegal RSSD S.A.'s defaults under the joint operating agreement, was approximately US$126 million. Additional payments of up to US$55 million are contingent on future commodity prices and timing of first oil. As a result of this acquisition, Woodside's participating interest in the RSSD joint venture increased to 82% for the Sangomar exploitation area and to 90% for the remaining RSSD evaluation area.

Principal factors that affect Woodside's results

Woodside's financial condition, operating cash flows and results of operations are affected by numerous factors. Woodside believes the following factors are of particular importance. However, other factors, including those outlined in Part 2 (*Risk Factors*) of this Prospectus may affect Woodside's financial condition and results of operations.

Oil and gas prices

Substantially all of Woodside's revenues from operations are derived from sales of LNG, condensate, oil, pipeline gas and LPG. Consequently, Woodside's results of operations are strongly influenced by the prices it receives for these products, which in general are wholly (in the case of oil and condensate) or partially (in the case of LNG, LPG and pipeline gas) determined by prevailing crude oil prices, which are affected by numerous factors beyond Woodside's control.

Woodside's long-term and mid-term LNG sales are generally priced with certain linkages to crude oil prices, primarily indexed to the Brent oil price or the crude oil basket known as the JCC.

Woodside's short-term LNG sales are increasingly being linked to JKM as the price reference. The JKM is an LNG benchmark price assessment for spot physical cargoes published by S&P Global Platts that is intended to reflect the spot market value of LNG cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan.

Woodside's oil and condensate sales are primarily priced on a Dated Brent marker and referenced to industry recognised oil benchmarks that are reported by Platts Crude Oil Market wire and on the electronic Intercontinental Exchange ("**ICE**"). The price of crude oil has been extremely volatile both historically and in recent times.

As shown in the table below, oil and gas prices recovered in 2021 from their 2020 lows to sit above 2019 levels. The 2021 price rally was driven by a confluence of factors, including OPEC+ supply management, capital discipline of U.S. suppliers and sanctions on the return of Iranian supply as well as a strong demand recovery at a time when storages were low as a result of a colder than average northern winter and a warmer than average northern summer. Record high European carbon prices and record low European storages set a new price anchor for JKM prices as buyers rushed to secure cargoes ahead of the northern winter.

	Units	2021	2020	2019
Dated Brent				
Average	US$/bbl	70.91	41.84	64.21
High	US$/bbl	86.12	69.96	74.69
Low	US$/bbl	50.34	13.24	53.24
3-month Lagged JCC				
Average	US$/bbl	59.95	51.21	69.77
High	US$/bbl	73.86	70.63	81.72
Low	US$/bbl	42.31	24.56	62.26
JKM				
Average	US$/MMBtu	15.17	3.85	5.97
High	US$/MMBtu	56.33	7.49	9.50
Low	US$/MMBtu	5.56	1.83	4.32

Currency fluctuations

Woodside's functional and reporting currency is U.S. dollars. As a result, its currency exposure relates to transactions and balances in currencies other than U.S. dollars. While substantially all of Woodside's revenues are denominated in U.S. dollars, its operating costs and exploration and development expenses are incurred in a mix of currencies, predominantly Australian dollars and U.S. dollars.

A large portion of Woodside's operating and capital expenditures is denominated in Australian dollars or other currencies and, consequently, depreciation of the Australian dollar (and such other currencies) against the U.S. dollar generally positively affects Woodside's overall profitability and financial position and decreases its effective costs, while appreciation of the Australian dollar has a generally negative effect on Woodside's overall profitability and financial position and increases its effective costs.

The Australian dollar is a commodity currency, and as such, strength in commodity prices such as iron ore are likely to cause an appreciation in the Australian dollar, while weakness in commodity prices have the opposite effect. In late 2020 and early 2021, the Australian economy being relatively protected from COVID-19 performed better than the US economy. This, together with an increase in iron ore and coal prices because of high Chinese demand and lower commodity supplies, combined with subdued U.S bond rates, resulted in an appreciation of the Australian dollar relative to the U.S. dollar. This represents a risk for Woodside's financial position because it increases Woodside's effective costs and therefore reduces net cash flow and profitability.

Woodside reviews its financial position based on movements in the Australian dollar relative to the U.S. dollar. Accordingly, in the ordinary course of business, Woodside may hedge currency requirements when there is a firm business requirement for the currency for operational purposes. In addition, Woodside seeks to minimise foreign exchange risk by incurring debt in U.S. dollars so that its repayment obligations more closely match its revenue streams.

AUD:USD	2021	2020	2019
Average	0.7507	0.6879	0.6952
High	0.7955	0.5756	0.6698
Low	0.7002	0.7686	0.7292

Capital and exploration expenditure

Woodside's capital expenditures vary from year to year depending on the projects that it is undertaking, their stage of development and Woodside's share of capital expenditures in these projects. However, Woodside's business does not generally require significant sustaining capital in order to maintain production. In addition, Woodside's exploration expenditures vary from year to year depending on its strategic priorities and the exploration projects which it undertakes.

Impairments

Woodside participates in a capital-intensive industry and from time to time, the value of Woodside's oil and gas properties, other plant and equipment, and investments may become impaired when, for example, commodity prices decline significantly for long periods of time, Woodside's reserve estimates are revised downward, or a decision to dispose of an asset leads to a write-down to its fair value. Woodside invests in exploration activities which, if proven to be unsuccessful, could lead to a material impairment of the carrying value of its exploration and evaluation assets.

During 2021, an impairment reversal of $582 million was recognised net of tax. The impairment reversal was a result of additional value generated by the Scarborough and Pluto Train 2 Cash Generating Unit and updated production profiles and improved short term pricing assumptions related to NWS Gas.

During 2020, impairment losses of $5,269 million were recognised on oil and gas properties and exploration and evaluation assets driven by a reduction in oil and gas price assumptions, increased longer-term demand uncertainty and other factors including increased risk of higher carbon pricing.

2 Results of operations

This paragraph describes Woodside's financial performance for the years ending 31 December 2021, 2020 and 2019

Corporate performance

The table presented below represents an abbreviated summary of Woodside's Consolidated Statement of Financial Position for the years ending 31 December 2021, 2020 and 2019.

	Units	2021	2020	2019
Operating revenue	**US$m**	6,962	**3,600**	**4,873**
Costs of production	US$m	(713)	(623)	(686)
Oil and gas properties depreciation and amortisation	US$m	(1,549)	(1,689)	(1,574)
Shipping and direct sales costs	US$m	(210)	(111)	(110)
Trading costs	US$m	(1,495)	(211)	(249)
Other hydrocarbon costs	US$m	(18)	(4)	(108)
Movement in onerous contract provision	US$m	140	(347)	—
Gross profit	**US$m**	3,117	**615**	**2,146**
Other income	US$m	139	31	100
Exploration and evaluation	US$m	(322)	(81)	(164)
Other costs	US$m	559	(5,736)	(991)
Profit / (loss) before tax and net finance costs	**US$m**	3,493	**(5,171)**	**1,091**
Net finance costs	US$m	(203)	(269)	(229)
Petroleum resource rent tax (PRRT) benefit	US$m	(297)	439	31
Tax (benefit) / expenses	US$m	(957)	1,026	(511)
Profit / (loss) after tax	**US$m**	2,036	**(3,975)**	**382**

Operating revenue

Total operating revenue increased US$3,362 million, or 93%, to US$6,962 million for the year ended 31 December 2021, from US$3,600 million for the year ended 31 December 2020, primarily due to increased trading activity and higher averaged realised prices as a result of the increase in Brent, JKM and lagged JCC prices (increase of US$3,161 million) as the combined impacts of strengthening demand from the improvement in the trading environment over the course of 2021 led to an increase in price markers for 2020. Woodside generated full year production of 91.1 MMboe during the year ended 31 December 2021 and delivered sales volumes of 111.6 MMboe (increase of US$165 million). In addition, shipping and other revenues increased by US$34 million for the year ended 31 December 2021, from US$7 million for the year ended 31 December 2020, primarily due to an increase in external shipping sub-chartering. Total operating revenue decreased US$1,273 million, or 26%, to US$3,600 million for the year ended 31 December 2020, from US$4,873 million for the year ended 31 December 2019, primarily due to lower averaged realised prices as a result of the decrease in Brent, JKM and lagged JCC prices (US$1,929 million) as the combined impacts of the COVID-19 pandemic, oversupply and weakened global demand led to a reduction in price markers for 2020. Woodside generated record full year production of 100.3 MMboe and accordingly, delivered record sales volumes of 106.8 MMboe which offset the impact of lower realised prices (US$573 million) coupled with higher processing, services, shipping and other revenues (US$15 million).

Cost of production

Cost of production increased US$90 million, or 14%, to US$713 million for the year ended 31 December 2021, from US$623 million for the year ended 31 December 2020, primarily due to higher royalties and excise costs (increase of US$136 million) due to higher pricing and associated revenue. This was offset by lower draw down of Woodside inventories (decrease of US$29 million) due to timing of activities on our FPSOs.

Cost of production decreased US$63 million, or 9%, to US$623 million for the year ended 31 December 2020, from US$686 million for the year ended 31 December 2019, primarily due to lower royalties and excise costs (US$111 million) as a result of lower operating revenues and lower production costs (US$27 million) which reflected a deferral of some maintenance into 2021 as part of Woodside's response to COVID-19 partially offset by unexpected COVID-19 management costs. Lower royalties, excise and production costs were offset by an increase in insurance costs (US$14 million) and an increase in costs associated with draw down of Woodside's inventories (US$61 million).

Oil and gas properties depreciation and amortisation

Oil and gas properties depreciation and amortisation decreased US$140 million, or 8%, to US$1,549 million for the year ended 31 December 2021, from US$1,689 million for the year ended 31 December 2020, primarily due to a reduction in asset values following the asset impairments recognised in July 2020 and lower oil production volumes as a result of weather events during 2021.

Oil and gas properties depreciation and amortisation increased US$115 million, or 7%, to US$1,689 million for the year ended 31 December 2020, from US$1,574 million for the year ended 31 December 2019, primarily due to reduced turnaround activity and a full year of production from the Ngujima-Yin FPSO following the Greater Enfield Project start-up in August 2019, offset by a reduction in asset values following the asset impairments recognised in July 2020.

Shipping and direct sales costs

Shipping and direct sales costs increased US$99 million, or 89%, to US$210 million for the year ended 31 December 2021, from US$111 million for the year ended 31 December 2020, primarily due to repurchase and cancellation costs incurred on revenue optimisation, in addition to higher shipping vessel charter and fuel costs in 2021.

Shipping and direct sales costs remained relatively stable with an increase of US$1 million, or 1%, to US$111 million for the year ended 31 December 2020, from US$110 million for the year ended 31 December 2019.

Trading costs

Trading costs increased US$1,284 million, or 609%, to US$1,495 million for the year ended 31 December 2021, from US$211 million for the year ended 31 December 2020, primarily due to higher average JKM and Dated Brent prices driving higher purchase costs on the LNG cargoes on-sold pursuant to the Pluto Transitional Marketing Arrangements Agreement, an increase in third party trades (2021: 21; 2020: 2) and an increase in Corpus Christi cargoes lifted (2021: 12; 2020: 4).

Trading costs decreased US$38 million, or 15%, to US$211 million for the year ended 31 December 2020, from US$249 million for the year ended 31 December 2019, primarily due to lower trading activity.

Other hydrocarbon costs

Other hydrocarbon costs and other costs of sales increased $14 million, or 350%, for the year ended 31 December 2021, from $4 million for the year ended 31 December 2020, which was primarily due to mitigation costs for contracted volumes.

Other hydrocarbon costs decreased US$104 million, or 96%, to US$4 million for the year ended 31 December 2020, from US$108 million for the year ended 31 December 2019, which was primarily due to purchase of mitigation cargoes resulting from major turnarounds at Pluto LNG and unplanned outages at Wheatstone in 2019.

Onerous contract provision

An onerous contract provision movement of US$140 million was recognised for the year ended 31 December 2021, comprising provisions used of US$45 million for cargoes sold and changes in estimates of US$95 million.

An onerous contract provision of US$447 million was recognised in relation to the Corpus Christi LNG sale and purchase agreement in June 2020. The provision was partially utilised during the period ($41 million) and was reassessed at 31 December 2020 with a further reduction of US$59 million to US$347 million. An onerous contract is one in which the unavoidable cost of meeting the obligations under the contract exceeds the expected economic benefit. The unavoidable cost of meeting the obligations is the lower of the net costs of fulfilling the contract or the cost of terminating it.

Other income

Other income increased US$108 million, or 348%, to US$139 million for the year ended 31 December 2021, from US$31 million for the year ended 31 December 2020, primarily due to income from Pluto volumes delivered into Wheatstone's sales commitments (increase of US$67 million) and net foreign exchange gains (increase of US$44 million).

Other income decreased US$69 million, or 69%, to US$31 million for the year ended 31 December 2020, from US$100 million for the year ended 31 December 2019, primarily due to a reduction in the liability previously recognised on jointly delivered LNG cargoes into Sales and Purchase Agreements under the Wheatstone Lifting Sales Coordination Agreement in 2019.

Exploration and evaluation expenses

Exploration and evaluation expenses increased US$241 million, or 298%, to US$322 million for the year ended 31 December 2021, from US$81 million for the year ended 31 December 2021, primarily due to capitalised costs written off due to Woodside's decision to withdraw from its interest in Myanmar (increase of US$209 million) and the Myanmar unsuccessful drilling campaign in H1 2021 (increase of US$56 million), offset by reduced exploration activity.

Exploration and evaluation expenses decreased US$83 million, or 51%, to US$81 million for the year ended 31 December 2020, from US$164 million for the year ended 31 December 2019, primarily due to reduced exploration activity.

Other costs

Other costs decreased US$6,295 million, or 110%, to US$(559) million for the year ended 31 December 2021, from US$5,736 million for the year ended 31 December 2020, primarily due to an impairment reversal of US$1,058 million on oil and gas properties compared to an impairment loss of US$5,269 million for the year ended 31 December 2020.

Other costs increased US$4,745 million, or 479%, to US$5,736 million for the year ended 31 December 2020, from US$991 million for the year ended 31 December 2019, primarily due to pre-tax impairment losses of US$5,269 million (US$3,923 million post-tax) which were recognised on oil and gas properties and exploration and evaluation assets driven by a reduction in oil and gas price assumptions, increased longer-term demand uncertainty and other factors including increased risk of higher carbon pricing.

Net finance costs

Net finance costs decreased US$66 million, or 25%, to US$203 million for the year ended 31 December 2021, from US$269 million for the year ended 31 December 2020, which reflected an decrease in finance costs (US$97 million), as a result of the 2021 US bond being redeemed on 10 February 2021 and interest capitalised against qualifying assets; and a decrease in finance income of US$31 million, or 53%, to US$27 million for the year ended 31 December 2021, from US$58 million for the year ended 31 December 2020, which reflected a reduction in interest from U.S. term deposits driven by lower interest rates and lower balances on deposit.

Net finance costs increased US$40 million, or 17%, to US$269 million for the year ended 31 December 2020, from US$229 million for the year ended 31 December 2019, which reflected an increase in finance costs (US$7 million), as a result of a full year of interest on the 2029 bond issued in March 2019 and the Syndicated Facilities drawn down in January 2020, and lower finance income (US$33 million), which reflected a reduction in U.S. term deposits driven by lower interest rates.

Petroleum resource rent tax

PRRT expense increased US$736 million, or 168%, to US$297 million for the year ended 31 December 2021, from a PRRT benefit of US$439 million for the year ended 31 December 2020, primarily due to the impact of the impairment reversal and the effect of higher operating revenue.

PRRT benefit increased US$408 million, or 1,316%, to US$439 million for the year ended 31 December 2020, from US$31 million for the year ended 31 December 2019, primarily due to the recognition of impairment losses and the effect of lower revenue.

Tax expense

Total tax expense increased US$1,983 million, or 193%, to US$957 million for the year ended 31 December 2021, from a tax benefit of US$1,026 million for the year ended 31 December 2020, primarily due to higher taxable income from the effect of higher revenue and impairment reversals in 2021, compared to lower revenue and the recognition of impairment losses in 2020.

Total tax benefit increased US$1,537 million, or 301%, to US$1,026 million for the year ended 31 December 2020, from (US$511) million for the year ended 31 December 2019, primarily due to the recognition of impairment losses and the effect of lower revenue.

Volumes, realised prices and operating revenues by product

The following Section describes movements in Woodside's operating revenues including a discussion of production volumes, sales volumes and realised prices for the years ending 31 December 2021, 2020 and 2019.

	Units	2021	2020	2019
Production Volumes				
LNG	MMboe	70.8	75.0	67.7
Domestic gas	MMboe	2.5	5.3	6.1
Condensate	MMboe	8.7	9.8	9.7
Oil	MMboe	8.6	9.7	5.6
LPG	MMboe	0.5	0.5	0.5
Total production	**MMboe**	**91.1**	**100.3**	**89.6**
Sales Volumes				
LNG	MMboe	91.2	81.2	75.3
Domestic gas	MMboe	2.5	5.3	6.2
Condensate	MMboe	8.7	10.2	9.7
Oil	MMboe	8.5	9.7	5.5
LPG	MMboe	0.7	0.4	0.7
Total sales volumes	**MMboe**	**111.6**	**106.8**	**97.4**
Average Realised Prices				
LNG	US$/boe	58	31	50
Domestic gas	US$/boe	17	14	14
Condensate	US$/boe	74	40	60
Oil	US$/boe	79	44	66
LPG	US$/boe	82	44	59
Volume-weighted average	**US$/boe**	**60**	**32**	**48**
Operating Revenues				
LNG	US$m	5,359	2,519	3,664
Domestic gas	US$m	43	73	85
Condensate	US$m	643	411	586
Oil	US$m	673	432	360
LPG	US$m	60	16	44
Other Revenue	US$m	184	149	134
Operating Revenues	**US$m**	**6,962**	**3,600**	**4,873**

LNG

Revenue from sales of LNG increased US$2,840 million, or 113%, to US$5,359 million for the year ended 31 December 2021, from US$2,519 million for the year ended 31 December 2020, primarily due to an increase in Woodside's average realised LNG price to US$58 per boe for the year ended 31 December 2021, from US$31 per boe for the year ended 31 December 2020, an increase of US$27 per boe or 87%, as a result of the continued strong demand for LNG and higher average JKM and JCC on linked sales. This was complemented by Woodside's LNG sales volume increasing by 10 MMboe, or 12%, to 91.2 MMboe for the year ended 31 December 2021, from 81.2 MMboe for the year ended 31 December 2020, primarily driven by an increase in third party trades.

Revenue from sales of LNG decreased US$1,145 million, or 31%, to US$2,519 million for the year ended 31 December 2020, from US$3,664 million for the year ended 31 December 2019, primarily due to a decrease in

Woodside's average realised LNG price to US$31 per boe for the year ended 31 December 2020, from US$50 per boe for the year ended 31 December 2019, a decrease of US$19 per boe or 38%, as the COVID-19 pandemic and lower demand for global LNG affected benchmark oil and gas prices. This was partially offset by Woodside's LNG sales volume increasing by 5.9 MMboe, or 7.8%, to 81.2 MMboe for the year ended 31 December 2020, from 75.3 MMboe for the year ended 31 December 2019, primarily driven by improved production and reliability performance at Pluto LNG following the completion of the planned maintenance shutdown in 2019 and at Wheatstone due to production optimisation initiatives implemented successfully in 2020.

Domestic gas

Revenue from sales of domestic gas decreased US$30 million, or 41%, to US$43 million for the year ended 31 December 2021, from US$73 million for the year ended 31 December 2020, due to a reduction in domestic gas sales volume which decreased 2.8 MMboe, or 53%, to 2.5 MMboe for the year ended 31 December 2021, from 5.3 MMboe for the year ended 31 December 2020. primarily driven by the expiration of domestic gas contract obligations in June 2020. Woodside's average realised domestic gas price of US$17 per boe for the year ended 31 December 2021, remained comparable to the average realised domestic gas price of US$14 per boe for the year ended 31 December 2020.

Revenue from sales of domestic gas decreased US$12 million, or 14%, to US$73 million for the year ended 31 December 2020, from US$85 million for the year ended 31 December 2019, due to a reduction in domestic gas sales volume which decreased 0.9 MMboe, or 14.5%, to 5.3 MMboe for the year ended 31 December 2020, from 6.2 MMboe for the year ended 31 December 2019. primarily driven by the expiration of domestic gas contract obligations. Woodside's average realised domestic gas price of US$14 per boe for the year ended 31 December 2020, remained stable from US$14 per boe for the year ended 31 December 2019.

Condensate

Revenue from sales of condensate increased US$232 million, or 56%, to US$643 million for the year ended 31 December 2021, from US$411 million for the year ended 31 December 2020, primarily due to an increase in Woodside's average realised condensate price to US$74 per boe for the year ended 31 December 2021, from US$40 per boe for the year ended 31 December 2020, an increase of US$34 per boe or 85%, as a result of higher average dated Brent. This was partially offset by a decrease in Woodside's condensate sales volume which decreased by 1.5 MMboe, or 15%, to 8.7 MMboe for the year ended 31 December 2021, from 10.2 MMboe for the year ended 31 December 2020, primarily driven by lower production volumes.

Revenue from sales of condensate decreased US$175 million, or 30%, to US$411 million for the year ended 31 December 2020, from US$586 million for the year ended 31 December 2019, primarily due to a decrease in Woodside's average realised condensate price to US$40 per boe for the year ended 31 December 2020, from US$60 per boe for the year ended 31 December 2019, a decrease of US$20 per boe or 33%. This was partially offset by an increase in Woodside's condensate sales volume which increased by 0.5 MMboe, or 5.2%, to 10.2 MMboe for the year ended 31 December 2020, from 9.7 MMboe for the year ended 31 December 2019, primarily driven by improved production and reliability performance at Pluto LNG, following the completion of the planned maintenance shutdown in 2019, and at Wheatstone due to production optimisation initiatives implemented successfully in 2020.

Crude oil

Revenue from sales of crude oil increased US$241 million, or 56%, to US$673 million for the year ended 31 December 2021, from US$432 million for the year ended 31 December 2020, due to an increase in average realised crude oil price to US$79 per boe for the year ended 31 December 2021, from US$44 per boe for the year ended 31 December 2020, an increase of US$35 per boe or 80%, as a result of higher Dated Brent prices. This was partially offset by lower sales volume of 1.2 MMboe, or 12%, to 8.5 MMboe for the year ended 31 December 2021, from 9.7 MMboe for the year ended 31 December 2020. The decrease in crude oil sales volume reflected lower production at Ngujima-Yin due to reduced facility reliability and impact of weather events.

Revenue from sales of crude oil increased US$72 million, or 20%, to US$432 million for the year ended 31 December 2020, from US$360 million for the year ended 31 December 2019, due to an increase in crude oil sales volume of 4.2 MMboe, or 76.4%, to 9.7 Mboe for the year ended 31 December 2020, from 5.5 MMboe for the year ended 31 December 2019. This increase in crude oil sales volume reflected a full year of production from the Ngujima-Yin FPSO, after the successful completion of the Greater Enfield Project in 2019, partially offset by lower production at the Okha FPSO due to maintenance activities and natural field decline. The increase in crude oil sales volumes was offset by a reduction in Woodside's average realised crude oil price to US$44 per boe for the year ended 31 December 2020, from US$66 per boe for the year ended 31 December 2019, a decrease of US$22 per boe or 33%.

LPG

Revenue from sales of LPG increased US$44 million, or 275%, to US$60 million for the year ended 31 December 2021, from US$16 million for the year ended 31 December 2020, primarily due to an increase in Woodside's average realised LPG price to US$82 per boe for the year ended 31 December 2021, from US$44 per boe for the year ended 31 December 2020, an increase of US$38 or 86%. In addition, Woodside's LPG sales volume increased 0.3 MMboe, or 75%, to 0.7 MMboe for the year ended 31 December 2021, from 0.4 MMboe for the year ended 31 December 2020.

Revenue from sales of LPG decreased US$28 million, or 64%, to US$16 million for the year ended 31 December 2020, from US$44 million for the year ended 31 December 2019, primarily due to a decrease in Woodside's average realised LPG price to US$44 per boe for the year ended 31 December 2020, from US$59 per boe for the year ended 31 December 2019, a decrease of US$15 or 25%. In addition, Woodside's LPG sales volume decreased 0.3 MMboe, or 42.9%, to 0.4 MMboe for the year ended 31 December 2020, from 0.7 MMboe for the year ended 31 December 2019, primarily driven by a reduction in production at North West Shelf.

Segment performance

The following describes the performance of Woodside's business segments for the years ending 31 December 2021, 2020 and 2019.

Woodside has identified its operating segments based on the internal reports that are reviewed and used by the executive management team in assessing performance and in determining the allocation of resources.

Management monitors the performance of the operating results of the segments separately for the purpose of making decisions about resource allocation and performance assessment. The performance of operating segments is evaluated based on profit before tax and net finance costs and is measured in accordance with Woodside's accounting policies.

Financing requirements, including cash and debt balances, finance income, finance costs and taxes for Woodside and its subsidiaries are managed at a group level.

Operating segments outlined below are identified by management based on the nature and geographical location of the business or venture.

Producing

North West Shelf Project – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas, condensate and liquefied petroleum gas in assigned permit areas.

Pluto LNG – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas and condensate in assigned permit areas.

Australia Oil – Exploration, evaluation, development, production and sale of crude oil in assigned permit areas (North West Shelf, Greater Enfield and Vincent).

Wheatstone – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas and condensate in assigned permit areas.

Development

Scarborough – Exploration, evaluation and development of liquified natural gas, pipeline natural gas and condensate in assigned permit areas.

Sangomar – Exploration, evaluation and development of crude oil in assigned permit areas.

Other Development – This segment comprises exploration, evaluation and development of liquefied natural gas, pipeline natural gas and condensate in the Browse, Kitimat and Sunrise projects.

Other Segments – This segment comprises trading and shipping activities and activities undertaken in other international locations.

Unallocated items – Unallocated items comprise primarily corporate non-segmental items of revenue and expenses and associated assets and liabilities not allocated to operating segments as they are not considered part of the core operations of any segment.

	Units	2021	2020	2019
North West Shelf				
Production volume	MMboe	24.7	30.8	32.0
Operating revenue	US$m	1,530	976	1,486
Gross profit	US$m	964	467	809
Profit / (loss) before tax and net finance costs	US$m	1,358	1	806
Pluto				
Production volume	MMboe	44.3	44.6	37.1
Operating revenue	US$m	2,794	1,587	2,064
Gross profit	US$m	1,474	388	827
Profit / (loss) before tax and net finance costs	US$m	2,197	(925)	797
Australia Oil				
Production volume	MMboe	8.6	9.7	5.6
Operating revenue	US$m	673	432	360
Gross profit	US$m	341	15	118
Profit / (loss) before tax and net finance costs	US$m	244	(735)	35
Wheatstone				
Production volume	MMboe	13.5	15.2	14.4
Operating revenue	US$m	772	486	709
Gross profit	US$m	407	73	226
Profit / (loss) before tax and net finance costs	US$m	356	(1,323)	330
Scarborough				
Production volume	MMboe	—	—	—
Operating revenue	US$m	—	—	—
Gross profit	US$m	—	—	—
Profit / (loss) before tax and net finance costs	US$m	—	(6)	—
Sangomar				
Production volume	MMboe	—	—	—
Operating revenue	US$m	—	—	—
Gross profit	US$m	—	—	—
Profit / (loss) before tax and net finance costs	US$m	2	(321)	(3)
Other Development				
Production volume	MMboe	—	—	—
Operating revenue	US$m	—	—	2
Gross profit	US$m	—	—	—
Profit / (loss) before tax and net finance costs	US$m	(24)	(953)	(725)

	Units	2021	2020	2019
Other Segments				
Production volume	MMboe	—	—	—
Operating revenue	US$m	1,193	119	252
Gross profit	US$m	(78)	(337)	158
Profit / (loss) before tax and net finance costs	US$m	(441)	(598)	(16)
Unallocated				
Production volume	MMboe	—	—	—
Operating revenue	US$m	—	—	—
Gross profit	US$m	9	9	8
Profit / (loss) before tax and net finance costs	US$m	(199)	(311)	(133)

North West Shelf

North West Shelf delivered full-year production of 24.7 MMboe for the year ended 31 December 2021 which represented a 6.1 MMboe decrease from production of 30.8 MMboe in the year ended 31 December 2020 driven by lower production volumes as a result of the expiration of domestic gas contract obligations in June 2020, cessation of the Angel well in October 2020 and a turnaround in June 2021. The decline in production was partially offset by higher realised prices and an increase in operating revenue of US$554 million, or 57%, to US$1,530 million in the year ended 31 December 2021 from US$976 million in the year ended 31 December 2020. Gross Profit increased US$497 million, or 106%, to US$964 million for the year ended 31 December 2021, from US$467 million for the year ended 31 December 2020. This was primarily driven by the increase in operating revenue and lower oil and gas properties depreciation and amortisation (decrease of US$49 million) partially offset by higher costs of production (increase of US$118 million). Profit / (loss) before tax and net finance costs increased by US$1,357 million, from US$1 million for the year ended 31 December 2020 to US$1,358 million for the year ended 31 December 2021. This change was primarily driven by an increase in Gross Profit, impairment reversals of US$376 million resulting from updated cost and production profiles and short-term pricing assumptions, and the impairment losses of US$454 million recognised at North West Shelf's oil and gas properties in 2020.

North West Shelf delivered full-year production of 30.8 MMboe for the year ended 31 December 2020 which represented a 4% decrease from production of 32.0 MMboe in the year ended 31 December 2019 driven by a decline in reservoir performance and planned major maintenance at KGP LNG Train 3 partially offset by improved LNG plant reliability of 98.0% compared to 97.0% in 2019. Lower production coupled with a broad-based decline in global energy prices due to the impacts of the COVID-19 pandemic resulted in lower realised prices and a reduction in operating revenue of US$510 million, or 34%, to US$976 million in the year ended 31 December 2020 from US$1,486 million in the year ended 31 December 2019. Gross Profit decreased US$342 million, or 42%, to US$467 million for the year ended 31 December 2020, from US$809 million for the year ended 31 December 2019. This was primarily driven by the decrease in operating revenue and partially offset by improved costs of production (decrease of US$121 million), lower oil and gas properties depreciation and amortisation (decrease of US$21 million) and lower other costs of sales (decrease of US$26 million). Profit / (loss) before tax and net finance costs decreased by US$805 million, from US$806 million for the year ended 31 December 2019 to US$1 million for the year ended 31 December 2020, a decrease of nearly 100%. This was primarily driven by a decrease in Gross Profit in addition to impairment losses of US$454 million recognised at North West Shelf's oil and gas properties.

Pluto

Pluto delivered full-year production of 44.3 MMboe for the year ended 31 December 2021 which remained relatively stable compared to production of 44.6 MMboe in the year ended 31 December 2020. Higher realised prices resulted in an increase in revenue of US$1,207 million to US$2,794 million in the year ended 31 December 2021, a 76% increase from US$1,587 million in the year ended 31 December 2020. Gross Profit increased US$1,086 million, or 280%, to US$1,474 million for the year ended 31 December 2021, from US$388 million for the year ended 31 December 2020. This was primarily driven by the increase in operating revenue partially offset by higher other costs of sales (increase of US$117 million). Profit / (loss) before tax and net finance costs increased by US$3,122 million, from US$(925) million for the year ended 31 December 2020 to

US$2,197 million for the year ended 31 December 2021, an increase of 338%. This was primarily driven by an increase in Gross Profit, impairment reversals of US$682 million resulting from additional value generated by the Scarborough-Pluto Cash Generating Unit following the final investment decision for Scarborough and Pluto Train 2 in November 2021, and impairment losses of $1,291 million recognized in 2020 at Pluto's oil and gas properties.

Pluto delivered record full-year production of 44.6 MMboe for the year ended 31 December 2020 which represented a 20% increase from production of 37.1 MMboe in the year ended 31 December 2019 during which production was impacted by Pluto's first major turnaround. Higher production was offset by a broad-based decline in global energy prices due to the impacts of the COVID-19 pandemic which resulted in lower realised prices and a reduction in revenue of US$477 million to US$1,587 million in the year ended 31 December 2020, a 23% decrease from US$2,064 million in the year ended 31 December 2019. Gross Profit decreased US$439 million, or 53%, to US$388 million for the year ended 31 December 2020, from US$827 million for the year ended 31 December 2019. This was primarily driven by the decrease in operating revenue and higher oil and gas properties depreciation and amortisation (increase of US$67 million) partially offset by improved costs of production (decrease of US$17 million) and lower other costs of sales (decrease of US$88 million). Profit / (loss) before tax and net finance costs decreased by US$1,722 million, from US$797 million for the year ended 31 December 2019 to US$(925) million for the year ended 31 December 2020, a decrease of 216%. This was primarily driven by a decrease in Gross Profit in addition to impairment losses of US$1,291 million recognised at Pluto's oil and gas properties in 2020.

Australia Oil

Australia Oil delivered full-year production of 8.6 MMboe for the year ended 31 December 2021 which represented a 11% decrease from production of 9.7 MMboe in the year ended 31 December 2020. This decrease reflected lower production at Ngujima-Yin FPSO due to reduced facility reliability and impact of weather events, partially offset by increase in production volumes at Okha FPSO. Higher operating revenues of US$673 million, an increase of US$241 million, or 56%, from US$432 million in the year ended 31 December 2020 were primarily driven by higher realised prices. Gross Profit increased US$326 million, or 2,173%, to US$341 million for the year ended 31 December 2021, from US$15 million for the year ended 31 December 2020. This was driven by lower costs of production (decrease of US$22 million) and lower depreciation and amortisation (decrease of US$63 million) for the year ended 31 December 2021. Profit / (loss) before tax and net finance costs increased by US$979 million, from US$(735) million for the year ended 31 December 2020 to US$244 million for the year ended 31 December 2021. This change was primarily driven by an increase in gross profit in 2021 and the impairment losses of $674 million recognized at Ngujima-Yin and Okha's oil and gas properties in 2020.

Australia Oil delivered full-year production of 9.7 MMboe for the year ended 31 December 2020 which represented a 73% increase from production of 5.6 MMboe in the year ended 31 December 2019. This increase reflected a full year of production from the Ngujima-Yin FPSO, after the successful completion of the Greater Enfield Project in 2019, partially offset by lower production at the Okha FPSO due to maintenance activities and natural field decline. Notwithstanding the decline in global oil prices in 2020, the increase in production led to higher operating revenues of US$432 million, an increase of US$72 million, or 20%, from US$360 million in the year ended 31 December 2019. Woodside temporarily shut-in production from the Cimatti field in 2020, reducing the sulphur content of crude produced at the Ngujima-Yin FPSO. This action delivered increased revenue for the year ended 31 December 2020 by enabling Woodside to capitalise on strong market demand for low sulphur fuel oil. Gross Profit decreased US$103 million, or 87%, to US$15 million for the year ended 31 December 2020, from US$118 million for the year ended 31 December 2019. This was driven by higher costs of production (increase of US$62 million) in 2020, as re-drilling of a Laverda well to support the Ngujima-Yin FPSO and production optimisation and subsea maintenance activities at the Okha FPSO were completed in the third quarter of 2020. In addition, the completion of the Greater Enfield Project in 2019 led to higher oil and gas properties depreciation and amortisation (increase of US$113 million) as a result of a full year of depreciation for the year ended 31 December 2020. Profit / (loss) before tax and net finance costs decreased by US$770 million, from US$35 million for the year ended 31 December 2019 to US$(735) million for the year ended 31 December 2020. This was primarily driven by a decrease in Gross Profit in addition to impairment losses of US$674 million recognised at Ngujima-Yin and Okha's oil and gas properties in 2020.

Wheatstone

Wheatstone delivered full year production of 13.5 MMboe for the year ended 31 December 2021 which represented a 11% decrease from production of 15.2 MMboe in the year ended 31 December 2020 driven by reliability performance and Train 1 turnaround. Lower production was offset by a broad-based rise in global energy prices which resulted in higher realised prices and an increase in revenue of US$286 million to US$772 million in the year ended 31 December 2021, a 59% increase from US$486 million in the year ended 31 December 2020. Gross Profit increased US$334 million, or 458%, to US$407 million for the year ended 31 December 2021, from US$73 million for the year ended 31 December 2020. This was primarily driven by the increase in operating revenue and lower costs of production (decrease of US$10 million), lower depreciation and amortisation (decrease of US$28 million) and lower other costs of sales (decrease of US$10 million). Profit / (loss) before tax and net finance costs increased by US$1,679 million, from US$(1,323) million for the year ended 31 December 2020 to US$356 million for the year ended 31 December 2021. This was primarily driven by an increase in Gross Profit and a decrease in impairment losses recognised on oil and gas properties of US$1,401 million for the year ended 31 December 2020.

Wheatstone delivered full year production of 15.2 MMboe for the year ended 31 December 2020 which represented a 6% increase from production of 14.4 MMboe in the year ended 31 December 2019 driven by strong reliability performance and production optimisation. Higher production was offset by a broad-based decline in global energy prices due to the impacts of the COVID-19 pandemic which resulted in lower realised prices and a reduction in revenue of US$223 million to US$486 million in the year ended 31 December 2020, a 31% decrease from US$709 million in the year ended 31 December 2019. Gross Profit decreased US$153 million, or 68%, to US$73 million for the year ended 31 December 2020, from US$226 million for the year ended 31 December 2019. This was primarily driven by the decrease in operating revenue and higher costs of production (increase of US$16 million), as Wheatstone continued its production ramp-up, partially offset by lower oil and gas properties depreciation and amortisation (decrease of US$44 million) and lower other costs of sales (decrease of US$42 million). Profit / (loss) before tax and net finance costs decreased by US$1,653 million, from US$330 million for the year ended 31 December 2019 to US$(1,323) million for the year ended 31 December 2020, a decrease of 501%. This was primarily driven by impairment losses of US$1,401 million recognised at Wheatstone's oil and gas properties in 2020, in addition to a decrease in Gross Profit.

Scarborough

In 2021, Woodside identified Scarborough as a separate operating segment within development due to the progress and materiality of the project.

Profit / (loss) before tax and net finance costs decreased by US$6 million from US$(6) million for the year ended 31 December 2020 to US$nil for the year ended 31 December 2021. This was primarily driven by US$3 million of redundancy costs and US$3 million of exchange losses recognised in 2020.

Sangomar

In 2021, Woodside identified Sangomar as a separate operating segment within development due to the progress and materiality of the project.

Profit / (loss) before tax and net finance costs increased by US$323 million from US$(321) million for the year ended 31 December 2020 to US$2 million for the year ended 31 December 2021. This was primarily driven by US$321 million of impairment losses recognised in 2020.

Profit / (loss) before tax and net finance costs increased by US$318 million from US$(3) million for the year ended 31 December 2020 to US$(321) million for the year ended 31 December 2020. This was primarily driven by US$321 million of impairment losses recognised on Sangomar's oil and gas properties.

Other Development

Woodside's Other Development segment relates to non-producing exploration, evaluation and development activities which did not generate any operating revenue or Gross Profit for the year ended 31 December 2021 or 2020.

Profit/(loss) before tax and net finance costs improved by US$929 million from US$(953) million for the year ended 31 December 2020 to US$(24) million for the year ended 31 December 2021. This was primarily driven by US$977 million of impairment losses recognised for Kitimat and Sunrise in 2020. Additionally, US$33 million was incurred in the Other Developments segment for various costs relating to Woodside's exit from the Kitimat LNG development.

Profit / (loss) before tax and net finance costs decreased by US$228 million from US$(725) million for the year ended 31 December 2019 to US$(953) million for the year ended 31 December 2020. This was primarily driven by US$977 million of impairment losses in 2020 recognised on Kitimat LNG's exploration and evaluation assets (impairment loss of US$809 million) and Sunrise's exploration and evaluation assets (impairment loss of US$168 million).

Other

Woodside's other segment is comprised primarily of trading and shipping activities undertaken in various international locations. These activities generated operating revenues of US$1,193 million for the year ended 31 December 2021, which represented an increase of US$1,074 million, or 903%, from US$119 million for the year ended 31 December 2020 which reflected greater market opportunities to trade LNG externally and sub-charter Woodside vessels in 2021. Gross Loss decreased US$259 million, or 77%, to US$(78) million for the year ended 31 December 2021, from US$(337) million for the year ended 31 December 2020 which was primarily driven by higher third party trades, increase in Corpus Christi cargoes lifted, positive movement in the onerous contract provision and an increase in external shipping sub-chartering, partially offset by higher trading and shipping costs (increase of US$1,301 million). Loss before tax and net finance costs decreased by US$157 million, from US$(598) million for the year ended 31 December 2020 to US$(441) million for the year ended 31 December 2021. This was primarily driven by a decrease in Gross Loss offset by capitalised costs written off due to Woodside's decision to withdraw from its interest in Myanmar and the Myanmar unsuccessful drilling campaign in the first half of 2021.

These other segment activities generated operating revenues of US$119 million for the year ended 31 December 2020, which represented a decline of US$133 million, or 53%, from US$252 million for the year ended 31 December 2019 which reflected fewer market opportunities to trade LNG externally and sub-charter Woodside vessels in 2020. Gross Profit decreased US$495 million, or 313%, to (US$337) million for the year ended 31 December 2020, from US$158 million for the year ended 31 December 2019 which was primarily driven by the recognition of US$347 million of onerous contract provisions in relation to the Corpus Christi LNG sale and purchase agreement and higher trading costs (increase of US$24 million). Profit / (loss) before tax and net finance costs decreased by US$582 million, from US$(16) million for the year ended 31 December 2019 to US$(598) million for the year ended 31 December 2020. This was primarily driven by a decrease in Gross Profit in addition to impairment losses of US$151 million recognised at two exploration retention leases (WA-93-R and WA94-R) in 2020.

Unallocated Items

Unallocated items are comprised primarily of corporate non-segmental items not allocated to operating segments. Gross Profit of US$9 million for the year ended 31 December 2021 is comparable to US$9 million for the year ended 31 December 2020. Loss before tax and net finance costs decreased by US$112 million, from US$(311) million for the year ended 31 December 2020 to US$(199) million for the year ended 31 December 2021 which was due to lower general, administrative and other costs, and a fair value gain on a repurchase agreement.

Gross Profit of US$9 million for the year ended 31 December 2020, represented an increase of US$1 million, or 13%, from US$8 million for the year ended 31 December 2019. Profit / (loss) before tax and net finance costs decreased by US$178 million, from US$(133) million for the year ended 31 December 2019 to US$(311) million for the year ended 31 December 2020 which was due to higher general, administrative and other costs primarily due to a one-off reconciliation of joint operating costs relating to prior years (increase of US$41 million), redundancy costs (increase of US$20 million), additional costs incurred as a result of COVID-19 (increase of US$17 million), higher foreign exchange losses primarily on Australian dollar denominated lease liabilities (increase of US$48 million) and losses on 2020 commodity hedges (increase of US$47 million).

3 Capital resources and liquidity

Woodside's primary sources of liquidity are (i) cash and cash equivalents, (ii) net cash provided by operating activities, (iii) unused borrowing capacity under its bilateral facilities and syndicated facility, (iv) issuances of debt or equity securities, and (v) other sources, such as sales of non-strategic assets. Details of Woodside's credit facilities, including total commitments, maturity and interest, and amount outstanding at 31 December 2021, can be found in Note C.2 of the Woodside Historical Financial Information included at Annexure 1 of this Prospectus.

Woodside's principal ongoing uses of cash are to meet working capital requirements to fund debt obligations and to finance Woodside's capital expenditures and acquisitions.

Cash flow analysis

The following Section describes movements in Woodside's cash flows for the years ending 31 December 2021, 2020 and 2019.

	Units	2021	2020	2019
Net cash from operating activities	US$m	3,792	1,849	3,305
Net cash used in investing activities	US$m	(2,941)	(2,112)	(1,238)
Net cash used in financing activities	US$m	(1,424)	(203)	317
Net increase in cash	**US$m**	(573)	**(466)**	**2,384**

Net cash from operating activities

Net cash from operating activities increased US$1,943 million, or 105%, to US$3,792 million for the year ended 31 December 2021, from US$1,849 million for the year ended 31 December 2020, driven by higher cash generated from operations (increase of US$1,875 million), lower borrowing costs relating to operating activities (decrease of US$89 million), lower income taxes paid (decrease of US$60 million) partially offset by lower interest income received (decrease of US$53 million), higher purchases of shares and payments relating to employee share plans (increase of US$15 million), and higher payments for restoration relating to Enfield and Echo Yodel (increase of US$15 million).

Net cash from operating activities decreased US$1,456 million, or 44%, to US$1,849 million for the year ended 31 December 2020, from US$3,305 million for the year ended 31 December 2019, driven by lower cash generated from operations (US$1,416 million), higher borrowing costs relating to operating activities (US$23 million), lower interest income received (US$21 million), higher income taxes paid (US$18 million) and higher payments for restoration (US$11 million) partially offset by lower purchases of shares and payments relating to employee share plans (US$34 million).

Net cash used in investing activities

Net cash used in investing activities increased US$829 million, or 39%, to US$2,941 million for the year ended 31 December 2021, from US$2,112 million for the year ended 31 December 2020, driven by higher payments for capital and exploration expenditure (increase of US$988 million) for Scarborough (which primarily relate to the contingent payment paid on Final Investment Decision) and Sangomar, higher advances to Petrosen under the loan facility.

Net cash used in investing activities increased US$874 million, or 71%, to US$2,112 million for the year ended 31 December 2020, from US$1,238 million for the year ended 31 December 2019, driven by payments associated with the completion of the acquisition of Cairn's interest in the RSSD Joint Venture (US$527 million) and higher payments for capital and exploration expenditure (US$205 million) which primarily relate to the Sangomar development, Julimar-Brunello Phase 2 and the Pyxis hub.

Net cash used in financing activities

Net cash used in financing activities increased US$1,221 million, or 601%, to US$(1,424) million for the year ended 31 December 2021, from US$(203) million for the year ended 31 December 2020, primarily due to higher repayment of borrowings (increase of US$701 million), lower proceeds from borrowings raised (decrease of US$600 million), higher lease repayments (increase of US$84 million) due to new drilling leases relating to Sangomar, partially offset by lower net dividends paid (decrease of US$165 million).

Net cash from financing activities decreased US$520 million, or 164%, to US$(203) million for the year ended 31 December 2020, from US$317 million for the year ended 31 December 2019, primarily due to lower proceeds from borrowings (US$1,100 million), higher lease repayments (US$30 million) and higher contributions to non-controlling interests (US$34 million) partially offset by lower dividends paid (US$608 million) and higher net proceeds from share issuance (US$23 million).

Capital expenditures

Woodside continued to progress the Scarborough and Pluto Train 2 developments, including completing technical feasibility studies to increase the design capacity of the offshore development. Woodside commenced project execution activities for the Sangomar field, including subsea fabrication and acquired FAR's interest in the RSSD joint venture, bringing Woodside's participating interest to 82%. Refer to Annexure 1 of Part 24 Note B.1 Segment production and growth assets for a breakdown of historic capital expenditure. Refer to paragraph 7 of Part 7 *(Overview of Woodside)* of this Prospectus for an overview of principal capital expenditure and divestitures currently in progress,

Off-balance sheet arrangements

Woodside has no off-balance sheet arrangements, aside from the contractual cash obligations outlined in paragraph 25 of Part 7 *(Overview of Woodside)* of this Prospectus , that have, or are reasonably likely to have, a current or future material effect on the Woodside Group's financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

4 Critical accounting estimates and policies

Woodside discussion and analysis of its financial condition and results of operations are based upon 2019, 2020 and 2021 financial statements, included in this Prospectus, which have been prepared in accordance with the requirements of the Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial statements comply with IFRS. The preparation of these financial statements requires management to make informed estimates and judgements that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

The critical accounting policies are as at 31 December 2019, 2020 and 2021, which are described in more detail in the notes to Woodside's financial statements in Annexure 1 to this Prospectus, which are included in an appendix to this Prospectus and are of particular importance to the portrayal of Woodside's financial position and results of operations and require the application of judgement by Woodside's management.

5 Quantitative and qualitative disclosures about market risk

In the normal course of business, Woodside is exposed to commodity price, foreign currency exchange rate and interest rate risks that could impact Woodside's financial position and results of operations. Woodside's risk management strategy with respect to these market risks may include the use of derivative financial instruments. Woodside uses derivative contracts to manage commodity price volatility, foreign exchange rate volatility on capital expenditure plans and interest rate exposure on financing activities.

Actual gains and losses in the future may differ materially from the sensitivity analysis based on changes in the timing and amount of commodity price, foreign currency exchange rate and interest rate movements and Woodside's actual exposures and derivatives in place at the time of the change, as well as the effectiveness of the derivative to hedge the related exposure.

Commodity price risk management

Woodside's revenue is exposed to commodity price fluctuations through the sale of hydrocarbons. Commodity price risks are measured by monitoring and stress testing Woodside's forecasted financial position to sustained periods of low oil and gas prices. This analysis is regularly performed on Woodside's portfolio and, as required, for discrete projects and transactions.

Foreign exchange rate risk management

Foreign exchange risk arises from future commitments, financial assets and financial liabilities that are not denominated in US dollars. The majority of Woodside's revenue is denominated in US dollars. Woodside is exposed to foreign currency risk arising from operating and capital expenditure incurred in currencies other than US dollars, particularly Australian dollars. Woodside has entered into forward arrangements to manage future A$ capex and opex.

Measuring the exposure to foreign exchange risk is achieved by regularly monitoring and performing sensitivity analysis on Woodside's financial position.

A reasonably possible change in the exchange rate of the US dollar to the Australian dollar (+12%/-12% (2019: +12%/-12%)), with all other variables held constant, would not have a material impact on Woodside's equity or the profit or loss in the current period. Refer to Part 24 *(Woodside Historical Financial Information)* and Annexure 1 of this Prospectus for details of the denominations of cash and cash equivalents, interest-bearing liabilities, receivables, payables and lease liabilities held at 31 December 2019 and 2020.

Interest rate risk

Interest rate risk is the risk that Woodside's financial position will fluctuate due to changes in market interest rates.

Woodside's exposure to the risk of changes in market interest rates relates primarily to financial instruments with floating interest rates including long-term debt obligations, cash and short-term deposits. Woodside manages its interest rate risk by maintaining an appropriate mix of fixed and floating rate debt. Woodside holds cross-currency interest rate swaps to hedge the foreign exchange risk and interest rate risk of the CHF denominated medium term note. Woodside also holds interest rate swaps to hedge the interest rate risk associated with the US$600 million syndicated facility.

Woodside's Treasury function is closely monitoring the market and the output from the various industry working groups managing the transition to new benchmark interest rates. The Treasury function is assessing the implications of the Interbank Offered Rates (IBOR) reform across Woodside and will manage and execute the transition from current benchmark rates to alternative benchmark rates.

6 Use of Non-IFRS Financial Measures

Certain parts of this Prospectus contain financial measures that have not been prepared in accordance with IFRS and are not recognised measures of financial performance or liquidity under IFRS. In addition to the financial information presented in accordance with IFRS contained in this Prospectus, certain "non-IFRS financial measures" have been included in this Prospectus. Woodside believes that these "non-IFRS financial measures" provide a useful means through which to examine the underlying performance of its business. These measures, however, should not be considered to be an indication of, or alternative to, corresponding measures of net profit or other figures determined in accordance with IFRS. In addition, such measures may not be comparable to similar measures presented by other companies. These measures include:

- EBIT, which is calculated as profit before income tax, Petroleum Resource Rent Tax ("**PRRT**") and net finance costs;
- Underlying EBITDA, which is calculated as profit before income tax, PRRT, net finance costs, depreciation and amortisation and impairment;
- Unlevered Free Cash Flow, which is calculated as Adjusted Operating Cash Flow minus payments for restoration and minus payments for capital expenditure;
- Adjusted Operating Cash Flow, which is calculated as net cash flow from operating activities excluding any financing costs (interest received, dividends received and borrowing costs relating to operating activities), add back payments for restoration and less payments for exploration expenditure;
- Gearing ratio, which is calculated as net debt (as defined below) divided by the sum of Net debt plus equity attributable to equity holders of the parent, expressed as a percentage;
- Gross margin, which is calculated as gross profit divided by operating revenue, excluding income tax, PRRT, net finance costs, other income and other expenses;
- Liquidity, which is calculated as the sum of cash on hand and undrawn committed debt facilities;
- Net debt, which is total debt and lease liabilities less cash and cash equivalents;
- Operating Cash Flow, which is calculated as net cash from operating activities excluding any financing costs (interest received, dividends received and borrowing costs relating to operating activities), add back payments for restoration and less payments for exploration expenditure;
- Return on average capital employed, calculated as EBIT divided by average non-current liabilities and average equity attributable to equity holders of the parent;
- Total available liquidity, which is undrawn facilities plus cash and cash equivalents;
- Underlying NPAT, which is net profit after tax adjusted for significant and other non-recurring items;

- Unit production costs (or “production costs per MMboe”), which are calculated as production costs (which, as used in this prospectus, are to productions costs, as reported in Woodside’s consolidated financial statements), divided by production volumes in MMboe for the relevant period; and
- Working capital surplus/(deficit), which is total current assets less total current liabilities.

Woodside believes that these measures provide useful supplemental measures of its operating performance as they permit investors to examine the underlying performance and financial condition of its business with a greater degree of comparability, and management considers these metrics in measuring Woodside’s operating performance and financial condition. These measures, however, should not be considered to be an indication of, or alternative to, corresponding measures of gross profit, net profit or cash flows determined in accordance with IFRS. Woodside’s presentation of these measures may not be comparable to similarly titled measures of other companies and are not measurements under IFRS or other generally accepted accounting principles. See the below table for reconciliation of non-IFRS financial measures.

Accordingly, undue reliance should not be placed on the non-IFRS financial measures contained in this prospectus, and the non-IFRS financial measures should not be considered in isolation or as a substitute for financial measures computed in accordance with IFRS. Although certain of these data have been extracted or derived from Woodside’s consolidated financial statements, these data have not been audited or reviewed by Woodside’s independent auditors.

A reconciliation of EBIT, underlying NPAT, underlying EBITDA and Free Cash Flow to Woodside’s financial statements are presented below:

	2021 US$m	2020 US$m	2019 US$m
Underlying EBITDA Reconciliation			
Profit/(loss) after tax	2,036	(3,975)	382
Add back: Income tax expense/(benefit)	957	(1,026)	511
Add back: Petroleum resource rent tax (PRRT) expense/(benefit)	297	(439)	(31)
Profit/(loss) before tax	3,290	(5,440)	862
Add back: Finance costs	230	327	320
Less: Finance income	(27)	(58)	(91)
EBIT	3,493	(5,171)	1,091
Add back: Depreciation & amortisation	1,690	1,824	1,703
Add back: Impairment	(1,048)	5,269	737
Underlying EBITDA	4,135	1,922	3,531
Underlying NPAT Reconciliation			
Profit/(loss) after tax	1,983	(4,028)	343
Add back: Impairment	(582)	3,923	720
Add back: Myanmar exploration and evaluation write-offs	209	—	—
Add back: Kitimat exit costs	33	—	—
Add back: Corpus Christi onerous contract	—	447	—
Add back: Joint operating costs relating to prior years	4	41	—
Add back: Price review adjustment relating to prior years	(27)	27	—
Add back: Redundancy costs	—	20	—
Add back: COVID-19 related costs	—	17	—
Underlying NPAT	1,620	447	1,063
Adjusted operating cash flows			
Net cash from operating activities	3,792	1,849	3,305
Less: Interest received	(11)	(64)	(85)
Less: Dividends received	(6)	(4)	(5)
Less: Payments for exploration expenditure	(283)	(310)	(461)
Add back: Borrowing costs relating to operating activities	91	180	157
Add back: Payments for restoration	38	23	12
Adjusted operating cash flows	3,621	1,674	2,923
Unlevered Free Cash Flow Reconciliation			
Adjusted operating cash flows	3,621	1,674	2,923
Less: Payments for restoration	(38)	(23)	(12)
Less: Payments for capital expenditure	(2,123)	(1,108)	(752)
Unlevered Free Cash Flow	1,460	543	**2,159**

Part 18 – Operating and Financial Review of BHP Petroleum

*The following Operating and Financial Review is a review of the operations and current financial position for the half year ended 31 December 2021 and for the financial years ended 30 June 2021, 2020 and 2019 which is prepared in accordance with IFRS. The information in this report should be read in conjunction with the audited and unaudited combined carve-out financial statements of the BHP Petroleum assets (referred to in this Operating and Financial Review as "**BHP Petroleum**") included in Annexure 2 (BHP Petroleum Historical Financial Information) of this Prospectus.*

Basis of Presentation

In August 2021, BHP Group Limited and Woodside entered into the Merger Commitment Deed to combine their respective oil and gas portfolios through an all-stock merger. On 22 November 2021, Woodside and BHP publicly announced that they had entered into the Share Sale Agreement under which, and subject to the terms and conditions therein, Woodside (or a nominee) will acquire all of the ordinary shares in BHP Petroleum International Pty Ltd, a wholly-owned subsidiary of BHP that will hold the oil and gas assets of BHP in exchange for the issuance of New Woodside Shares and the Completion Payment (subject to adjustment).

The financial information of the BHP Petroleum assets included in this Prospectus has been extracted on a "carve-out" basis from the accounting records of BHP Group Limited for the purposes of presenting the combined financial position, combined results of operations and combined cash flows of BHP Petroleum. The BHP Petroleum assets are hereinafter referred to as "**BHP Petroleum**" and, unless context otherwise requires, its subsidiaries, after giving effect to the Restructure, and exclude the following entities: BHP BK Limited, BHP Billiton Petroleum Great Britain Limited, BHP Mineral Resources Inc., BHP Copper Inc., Resolution Copper Mining LLC, BHP Resolution Holdings LLC and BHP Capital Inc. BHP Petroleum's unaudited combined financial statements as of and for the six months ended 31 December 2021, BHP Petroleum's audited combined financial statements as of 30 June 2021 and 2020 and for the years ended 30 June 2021 and 2020 and BHP Petroleum's unaudited combined financial statements as of and for the year ended 30 June 2019, included in this Prospectus (collectively, the "**Combined Financial Statements**"), are presented in U.S. dollars. Consistent with applicable reporting rules, the BHP Petroleum non-statutory half-year financial information as of and for the six months ended 31 December 2021 and the BHP Petroleum financial information as of and for the year ended 30 June 2019 is unaudited.

In September 2018, BHP Petroleum completed the sale of 100% of the issued share capital of BHP Billiton Petroleum (Arkansas) Inc. and 100% of the membership interest in BHP Billiton Petroleum (Fayetteville) LLC, which held the Fayetteville assets. On 31 October 2018, BHP Petroleum completed the sale of 100% of the issued share capital of Petrohawk Energy Corporation, the subsidiary which held the Eagle Ford (being Black Hawk and Hawkville), Haynesville and Permian assets, for a gross cash consideration of US$10.3 billion (net of preliminary customary completion adjustments of US$0.2 billion). As a result, BHP Petroleum has reclassified the Onshore U.S. asset results to discontinued operations for the financial year ended 30 June 2019 and recorded a loss of US$335 million in discontinued operations.

Boe disclosure

A boe conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Accordingly, disclosures in respect of a boe should not be read in isolation.

Impact of Coronavirus Disease 2019 (COVID-19) Pandemic

BHP Petroleum continues to actively monitor the impact of the COVID-19 pandemic, including the impact on economic activity and financial reporting. During the period, BHP Petroleum continued to experience lower volumes at certain of BHP Petroleum's operated assets and to incur incremental directly attributable costs, including those associated with the increased provision of health and hygiene services, the impacts of maintaining social distancing requirements and demurrage and other standby charges related to delays caused by COVID-19.

As the pandemic continues to evolve, with the extent and timing of impacts varying across BHP Petroleum's key operating locations, it remains difficult to predict the full extent and duration of resulting operational and economic impacts for BHP Petroleum. This uncertainty impacts judgements made by BHP Petroleum, including those relating to assessing the collectability of receivables and determining the recoverable values of BHP Petroleum's non-current assets. Given the uncertainty associated with the pandemic, management assesses the appropriate financial treatment and disclosure of COVID-19 impacts each reporting period.

The ongoing uncertainty has also been considered in BHP Petroleum's assessment of the appropriateness of adopting the going concern basis of preparation of the BHP Petroleum Combined Financial Statements. In assessing the appropriateness of the going concern assumption over the going concern period, management has stress tested BHP Petroleum's most recent financial projections to incorporate a range of potential future outcomes by considering BHP Petroleum's principal risks. BHP Petroleum's financial forecasts, including downside commodity price and production scenarios, demonstrate that BHP Petroleum believes that it has sufficient financial resources to meet its obligations as they fall due throughout the going concern period. As such, the BHP Petroleum Combined Financial Statements continue to be prepared on the going concern basis.

1 Business Overview, Strategy and Key Performance Drivers

Business Environment

BHP Petroleum's assets comprise of conventional oil and gas assets located in the U.S. GOM, Australia, T&T, Algeria and Mexico, and appraisal and exploration options in T&T, central and western U.S. GOM, Eastern Canada, Barbados and Egypt. The crude oil and condensate, gas and NGLs produced by BHP Petroleum's assets are sold on the international spot market or domestic market.

BHP Petroleum's financial results are significantly influenced by fluctuations in commodity prices, and production volumes.

Six months ended 31 December 2021

The following table depicts BHP Petroleum's average realised prices and total petroleum production for the six months ended 31 December 2021 and 2020:

Six months ended 31 December	**Unaudited 2021 US$m**	Unaudited 2020 US$m
Total petroleum production (MMboe)	**53**	50
Average realised prices		
Oil (crude and condensate) (US$/bbl)	**73.62**	41.24
Natural gas (US$/Mscf)	**5.78**	3.83
Liquefied natural gas (US$/Mscf)	**15.10**	4.45

Trends in each of the major markets during the six months ended 31 December 2021 and 2020 are outlined below.

Crude oil

BHP Petroleum's average realised sales price for crude oil for the six months ended 31 December 2021 was US$73.62 per barrel (31 December 2020: US$41.24 per barrel). Crude oil prices traded in an approximate range of US$65- 85/bbl (Brent) during the six months ended 31 December 2021. BHP Petroleum believes that further gains after the period end are possible given its constructive view of demand tailwinds. However, future developments in price are also expected to rely in large part on the rate at which currently curtailed supply returns, which is highly uncertain. Looking beyond this phase, BHP Petroleum's bottom-up analysis of demand, allied to systematic field decline rates, points to a long run structural supply-demand gap. Considerable investment in conventional oil is going to be required to fill that gap and maintain market balance. If that investment is not forthcoming in a timely way, the impact on oil prices is uncertain, including the possibility of material increases in oil prices.

Liquefied natural gas (LNG)

BHP Petroleum's average realised sales price for LNG for the six months ended 31 December 2021 was US$15.10 per Mcf (31 December 2020: US$4.45 per Mcf). The JKM price for LNG has been extremely elevated, with all-time high spot pricing achieved in the lead-up to the northern hemisphere winter. Longer term, assets advantaged by their proximity to existing infrastructure or customers, or both, in addition to competitive emissions intensities, are expected to be attractive.

Impact of changes to commodity prices

The prices BHP Petroleum obtains for its products are a key driver of value for BHP Petroleum. Fluctuations in these commodity prices affect BHP Petroleum's results, including cash flows and asset values. The estimated impact of changes in commodity prices for the six months ended 31 December 2021 on BHP Petroleum's key financial measures is set out below. The sensitivity calculations are performed independently and show the effect of changing one variable while holding all other variables constant..

For the half year ended 31 December 2021 (unaudited)	Impact on profit after taxation (US$M)	Impact on Underlying EBITDA (US$M)(1)
US$1/bbl on oil price	14	21
US¢0.10/Mcf on natural gas price	8	12
US¢1/Mcf on LNG price	3	5
US$1/bbl on NGL price	3	4

(1) Underlying EBITDA is a non-IFRS financial measure.

Production

Total petroleum production for the six months ended 31 December 2021 increased by 5% to 53 MMboe from the six months ended 31 December 2020.

Crude oil, condensate and NGL production increased by 13% to 25 MMboe, reflecting the additional 28% working interest acquired in Shenzi in November 2020, increased volumes from Ruby following first production in May 2021, and absence of impacts from weather events in the U.S. GOM in comparison to the prior period, partially offset by natural field decline across the portfolio.

Natural gas production decreased by 1% to 169 bcf, reflecting decreased production at North West Shelf and natural field decline across the portfolio, partially offset by increased volumes from Ruby and higher demand for gas at Bass Strait.

BHP Petroleum costs

BHP Petroleum unit costs are calculated as a ratio of net costs of the assets to the equity share of production and BHP Petroleum believes they provide a consistent benchmark relative to volumes, that is in line with external market comparisons. This is a calculation based on costs directly associated with production (i.e. production cost base).

BHP Petroleum unit costs exclude:

- freight, as BHP Petroleum believes doing so provides a similar basis of comparison to its peer group;
- exploration, development and evaluation expense, as these costs do not represent its cost performance in relation to current production and BHP Petroleum believes it provides a similar basis of comparison to its peer group; and
- other costs that do not represent underlying cost performance of BHP Petroleum.

BHP Petroleum unit costs for the six months ended 31 December 2021 increased by 2% to US$10.51 per barrel of oil equivalent from the six months ended 31 December 2020 due to increased price-linked costs and increased maintenance and integrity activities in T&T. The calculation of petroleum unit costs for the six months ended 31 December 2021 and 2020 is set out in the tables below.

Half year ended 31 December 2021 and 2020

For the half year ended 31 December	Unaudited 2021 US$M	Unaudited 2020 US$M
Expenses excluding finance costs [(1)]	**1,761**	1,816
Less:		
Depreciation and amortisation expense	**1,047**	890
Net impairments	**210**	61
Exploration and evaluation and expenditure incurred and expensed in the period	**112**	181
Development and evaluation	**79**	106
Freight (post-port)	**46**	22
Other non-producing costs [(2)]	**(290)**	41
Net costs [(3)]	**557**	515
Production (MMboe, equity share)	**53**	50
Cost per Boe (US$)	**10.51**	10.30

(1) Expenses excluding finance costs for the half year ended 31 December 2021 and 2020 has been derived from BHP Petroleum's unaudited Combined Financial Statements for the half year ended 31 December 2021.

(2) Other non-producing costs includes over/underlifts, inventory movements, foreign exchange, third-party costs and the impact from revaluation of embedded derivatives in the T&T gas contract.

(3) Net costs is a non-IFRS financial measure and is reconciled to the nearest respective IFRS measure, Expenses excluding finance costs. The measure and reconciliation above is for the half year ended 31 December 2021 and the comparative periods are unaudited and have been derived from BHP Petroleum's unaudited Combined Financial Statements.

Financial years ended 30 June 2021, 2020 and 2019

The following table depicts BHP Petroleum's average realised prices and total petroleum production for the financial years ended 30 June 2021, 2020 and 2019:

For the financial year ended 30 June	2021 US$M	2020 US$M	2019 US$M
Total petroleum production (MMboe)	**103**	109	121
Average realised prices			
Oil (crude and condensate) (US$/bbl)	**52.56**	49.53	66.59
Natural gas (US$/Mscf)	**4.34**	4.04	4.55
Liquefied natural gas (US$Mscf)	**5.63**	7.26	9.43

Trends in each of the major markets for the financial years ended 30 June 2021, 2020 and 2019 are outlined below.

Crude oil

BHP Petroleum's average realised sales price for crude oil for FY2021 was US$52.56 per barrel (FY2020: US$49.53 per barrel). Brent crude oil prices steadily increased through FY2021, rising from around US$40/bbl at the beginning of FY2021 to around US$75/bbl at the close. A recovery in business activity and mobility as economies reduced COVID-19 controls has supported oil demand. Supply side curtailments from OPEC+ and capital restraint from U.S. operators supported oil inventories to rebalance globally.

BHP Petroleum's average realised sales price for crude oil for FY2020 was US$49.53 per barrel (FY2019: US$66.59 per barrel). Crude oil prices dropped significantly in the second half of FY2020 due to a brief OPEC+ price war in March 2020 and COVID-19, with Brent falling below US$20/bbl in April 2020 at the height of the global lockdowns and peak demand destruction. The prices partially recovered in FY2020 mainly due to swift output cuts from OPEC+ and a partial recovery in mobility. Very large storage builds flipped to draws in late May 2020, which allowed benchmark prices to move up to approximately US$40/bbl.

Liquefied natural gas (LNG)

BHP Petroleum's average realised sales price for LNG for FY2021 was US$5.63 per Mcf (FY2020: US$7.26 per Mcf). The JKM price for LNG performed strongly in FY2021, hitting an all-time high in January 2021 supported by cold weather, recovery in China, high European gas prices, unplanned outages and less incremental supply coming online.

BHP Petroleum's average realised sales price for LNG for FY2020 was US$7.26 per Mcf (FY2019: US$9.43 per Mcf). The JKM price for LNG performed poorly in FY2020, reflecting a deepening oversupply situation. JKM hit an all-time low in April 2020 as a slowdown in Asian demand growth due to warm weather and COVID-19 and large increments of new supply coming online weighed on the market.

Impact of changes to commodity prices

The estimated impact of changes in commodity prices for the financial year ended 30 June 2021 on BHP Petroleum's key financial measures is set out below. The sensitivity calculations are performed independently and show the effect of changing one variable while holding all other variables constant.

For the financial year ended 30 June 2021	**Impact on profit after taxation (US$M)**	**Impact on Underlying EBITDA (US$M)[1]**
US$1/bbl on oil price	24	35
US¢0.10/Mcf on natural gas price	15	23
US¢1/Mcf on LNG price	8	12
US$1/bbl on NGL price	4	7

(1) Underlying EBITDA is a non-IFRS financial measure.

Production

Total petroleum production for FY2021 decreased by 6% to 103 MMboe from FY2020.

Crude oil, condensate and NGL production decreased by 6% to 46 MMboe due to natural field decline across the portfolio, a highly active hurricane season in the U.S. GOM in the first half of the financial year and downtime at Atlantis, with tie-in activity in the first half of the year and unplanned downtime in the March 2021 quarter. These impacts were partially offset by the earlier than scheduled achievement of first production from the Atlantis Phase 3 project in July 2020 and the additional working interest acquired in Shenzi, completed on 6 November 2020.

Natural gas production decreased by 5% to 341 bcf, reflecting planned shutdowns at Angostura related to the Ruby tie-in, lower gas demand at Bass Strait and natural field decline across the portfolio. The decrease was partially offset by improved reliability at Bass Strait and higher domestic gas sales at Macedon.

Total production for FY2020 decreased by 10% to 109 MMboe from FY2019.

Crude oil, condensate and NGL production decreased by 11% to 49 MMboe due to the impacts of Tropical Storm Barry in the U.S. GOM, Tropical Cyclone Damien at BHP Petroleum's North West Shelf operations, maintenance at Atlantis and natural field decline across the portfolio. Weaker market conditions, including impacts from COVID-19, also contributed to lower volumes in the June 2020 quarter. This decline was partially offset by higher uptime at Pyrenees following the 70-day dry dock maintenance programme during the prior year.

Natural gas production decreased by 9% to 360 bcf, reflecting a decrease in both production and tax barrels (in accordance with the terms of BHP Petroleum's Production Sharing Contract) due to weaker market conditions in T&T, impacts of maintenance and Tropical Cyclone Damien at North West Shelf and natural field decline across the portfolio.

BHP Petroleum costs

BHP Petroleum unit costs for FY2021 increased by 11% to US$10.83 per barrel of oil equivalent from FY2020 due to lower volumes and unfavourable exchange rate movements, partially offset by a reduction in price-linked costs. The calculation of petroleum unit costs for the financial years ended 30 June 2021, 2020 and 2019 is set out in the table below. For further information regarding the calculation of BHP Petroleum unit costs, see "*Six months ended 31 December 2021 and 2020*" above.

For the financial year ended 30 June	2021 US$M	2020 US$M	Unaudited 2019 US$M
Expenses excluding finance costs (1)	**3,799**	3,390	3,510
Less:			
Depreciation and amortisation expense	**1,840**	1,457	1,560
Net impairments	**127**	11	21
Exploration and evaluation and expenditure incurred and expensed in the period	**296**	395	388
Development and evaluation	**196**	166	46
Freight (post-port)	**81**	83	118
Other non-producing costs (2)	**144**	216	102
Net costs (3)	**1,115**	1,062	1,275
Production (MMboe, equity share)	**103**	109	121
Cost per Boe (US$)	**10.83**	9.74	10.54

(1) Expenses excluding finance costs for FY2021 and FY2020 has been derived from BHP Petroleum's audited Combined Financial Statements for the years ending 30 June 2021 and 2020. Expenses excluding finance costs for FY2019 has been derived from BHP Petroleum's unaudited Combined Financial Statements for the year ending 30 June 2019.

(2) Other non-producing costs includes over/underlifts, inventory movements, foreign exchange, provision for onerous lease contracts, third-party costs and the impact from revaluation of embedded derivatives in the T&T gas contract.

(3) Net costs is a non-IFRS financial measure and is reconciled to the nearest respective IFRS measure, Expenses excluding finance costs. The measure and reconciliation above is for the financial year ended 30 June 2021 and comparative periods are unaudited and have been derived from BHP Petroleum's Combined Financial Statements.

2 Financial results

Six months ended 31 December 2021 and 2020

The following table provides more information on the profit/loss from operations and Underlying EBITDA of BHP Petroleum, including a reconciliation between Underlying EBITDA and the nearest IFRS measure, for the six months ended 31 December 2021 and 2020. The measures and reconciliations below are included in this section for the six months ended 31 December 2021 and comparative period are unaudited and have been derived from the BHP Petroleum Combined Financial Statements.

Six months ended 31 December	Unaudited 2021 US$M	Unaudited 2020 US$M
Profit/(loss) from operations	**1,608**	(199)
Depreciation and amortisation expense	**1,047**	890
Net impairments	**210**	61
Other	**5**	7
Underlying EBITDA(1)	**2,870**	759

(1) Underlying EBITDA is a non-IFRS financial measure.

Profit/(loss) from operations

Profit from operations in the six months ended 31 December 2021 increased by US$1,807 million to US$1,608 million from the six months ended 31 December 2020. This is primarily driven by an increase in average realised sales prices of crude oil, natural gas and LNG, coupled with an increase in volumes. This increase is partially offset by an impairment charge of US$210 million against property, plant and equipment, relating to the Ruby operations in offshore T&T, in the six months ended 31 December 2021. The impairment reflects revisions to estimated reserves resulting from technical analysis of well drilling results and performance following project completion in December 2021.

Underlying EBITDA

Underlying EBITDA is used to help assess current operational profitability, excluding the impacts of sunk costs (i.e. depreciation from initial investment). It is a measure that management uses internally to assess the performance of BHP Petroleum. Underlying EBITDA is a non-IFRS financial measure.

Underlying EBITDA in the six months ended 31 December 2021 increased by US$2,111 million to US$2,870 million, or 278% from the six months ended 31 December 2020. Price impacts, net of price-linked costs, increased Underlying EBITDA by US$1,767 million due to higher average realised crude oil, natural gas and LNG prices. Volume impacts increased underlying EBITDA by US$170 million due to higher gas demand at Bass Strait, increased volumes from Ruby following first production in May 2021 and the absence of impacts from weather events in the U.S. GOM. Additionally, Underlying EBITDA improved due to the recognition of a US$104 million gain attributable to the Final Investment Decision ("**FID**") of the Scarborough LNG project pursuant to the 2016 divestment of BHP Petroleum's 25% Scarborough Joint Venture interest to Woodside (payable upon FID which was announced in November 2021). Controllable cash costs had a favourable impact of US$52 million due to increased maintenance and integrity activities in T&T and the impact of expensing the Wasabi-1 well, more than offset by the impact from expensing the Broadside-1 well and seismic costs in the U.S. GOM and T&T in the prior period.

Financial years ended 30 June 2021, 2020 and 2019

The following table provides more information on the revenue and expenses of BHP Petroleum for the financial years ended 30 June 2021, 2020 and 2019.

Financial Year ended 30 June	2021 US$M	2020 US$M	Unaudited 2019 US$M
Combined Income Statement			
Continuing operations			
Revenue	**3,909**	3,997	5,867
Other income	**130**	57	32
Expenses excluding net finance costs	**(3,799)**	(3,390)	(3,510)
Loss from equity accounted investments	**(6)**	(4)	(2)
Profit from operations	**234**	660	2,387
Financial expenses	**(464)**	(660)	(1,001)
Financial income	**56**	304	364
Net finance costs	**(408)**	(356)	(637)
Profit/(loss) before taxation	**(174)**	304	1,750
Income tax expense	**(211)**	(400)	(925)
Royalty-related taxation (net of income tax benefit)	**24**	(82)	(164)
Total taxation expense	**(187)**	(482)	(1,089)
Profit/(loss) after taxation from Continuing operations	**(361)**	(178)	661
Discontinued operations			
Loss after taxation from Discontinued operations	**—**	—	(335)
Profit/(loss) after taxation from Continuing and Discontinued operations	**(361)**	(178)	326
Attributable to non-controlling interests	—	—	7
Attributable to BHP shareholders	**(361)**	(178)	319
Other financial information			
Underlying EBITDA[(1)]	**2,238**	2,164	4,061

(1) Underlying EBITDA is a non-IFRS financial measure.

Revenue

Revenue of US$3,909 million in FY2021 decreased by US$88 million, or 2%, from FY2020. This decrease was primarily attributable to decreased production due to natural field decline and weather downtime in the U.S. GOM, offset by higher average realised prices for crude oil and natural gas.

Revenue of US$3,997 million in FY2020 decreased by US$1,870 million, or 32%, from FY2019. This decrease was primarily attributable to lower average realised prices for crude oil, LNG and natural gas and decreased production volume due to natural field decline, decreased tax barrels at T&T and weaker market conditions.

Other Income

Other income of US$130 million in FY2021 increased by US$73 million, or 128% from FY2020. This increase was primarily attributable to gain on the divestment of BHP Petroleum's 35% interest in the U.S. GOM Neptune field in May 2021.

Other income of US$57 million in FY2020 increased by US$25 million, or 78%, from FY2019. This increase was primarily attributable to dividend income.

Total expenses excluding net finance costs

Total expenses excluding net finance costs of US$3,799 million in FY2021 increased by US$409 million, or 12%, from FY2020. This includes an increase of US$383 million depreciation and amortisation expenses following a decrease in estimated remaining reserves at Bass Strait due to underperformance of the reservoir and a US$97 million net impairment relating to write-offs of previously capitalised exploration and evaluations costs.

Total expenses excluding net finance costs of US$3,390 million in FY2020 decreased by US$120 million, or 3%, from FY2019. This includes a decrease of US$103 million depreciation and amortisation expenses due to lower production.

Net finance costs

Net finance costs of US$408 million in FY2021 increased by US$52 million, or 15%, from FY2020. This was primarily attributable to decreased finance income related to lower related party loan balances.

Net finance costs of US$356 million in FY2020 decreased by US$281 million, or 44%, from FY2019. This was primarily attributable to the repayment of related party debt and reduced interest rates.

Taxation expense

Total taxation expense of US$187 million in FY2021 decreased by US$295 million, or 61%, from FY2020. The decrease was primarily driven by lower profits.

Total taxation expense of US$482 million in FY2020 decreased by US$607 million, or 56%, from FY2019. The decrease was primarily driven by lower profits.

Underlying EBITDA

Underlying EBITDA is used to help assess current operational profitability, excluding the impacts of sunk costs (i.e. depreciation from initial investment). It is a measure that management uses internally to assess the performance of BHP Petroleum. Underlying EBITDA is a non-IFRS financial measure.

Underlying EBITDA in FY2021 increased by US$74 million to US$2,238 million, or 3% from FY2020. Price impacts, net of price-linked costs, increased Underlying EBITDA by US$257 million due to higher average realised crude oil and natural gas prices. The increase was partially offset by lower production of US$157 million due to natural field decline, unfavourable impacts from a highly active hurricane season in the U.S. GOM and lower gas demand at Bass Strait, partially offset by the acquisition of the additional 28% working interest in Shenzi.

Underlying EBITDA in FY2020 decreased by US$1,897 million to US$2,164 million, or 47% from FY2019. Price impacts, net of price-linked costs, decreased Underlying EBITDA by US$1,133 million due to lower average realised crude oil and natural gas prices. Lower production volume of US$588 million also unfavourably impacted Underlying EBITDA driven by natural field decline, weaker market conditions due to excess global supply, impacts from Tropical Cyclone Barry and Tropical Cyclone Damien and planned maintenance at Atlantis. Increased controllable cash costs of US$30 million and cessation of operations at Minerva and the sale of BHP Petroleum's interests in the Bruce and Keith oil and gas fields in the prior period of US$76 million also unfavourably impacted Underlying EBITDA. Exchange rates decreased Underlying EBITDA US$34 million.

The following table provides a reconciliation between Underlying EBITDA and the nearest respective IFRS measure. The measures and reconciliations below are included in this section for the financial year ended 30 June 2021 and comparative periods are unaudited and have been derived from the BHP Petroleum Combined Financial Statements.

Financial Year ended 30 June	**Unaudited 2021 US$m**	Unaudited 2020 US$m	Unaudited 2019 US$m
Profit from operations (1)	**234**	660	2,387
Depreciation and amortisation expense	**1,840**	1,457	1,560
Net impairments	**127**	11	21
Other	**37**	36	93
Underlying EBITDA	**2,238**	2,164	4,061

(1) Profit from operations FY2021 and FY2020 has been derived from BHP Petroleum's audited Combined Financial Statements for the financial years ending 30 June 2021 and 2020. Profit from operations FY2019 has been derived from BHP Petroleum's unaudited Combined Financial Statements for the financial year ended 30 June 2019.

Cash flows

Six months ended 31 December 2021 and 2020

Net operating cash flows of US$1,388 million (31 December 2020: US$106 million) reflects higher revenues due to an increase in average realised sales prices of crude oil, natural gas and LNG, coupled with an increase in volumes, partially offset by unfavourable working capital impacts and increased taxes paid during the period.

Financial years ended 30 June 2021, 2020 and 2019

The following table provides a summary of the Combined Cash Flow Statement for the financial years ended 30 June 2021, 2020 and 2019:

Financial year ended 30 June	**2021 US$M**	**2020 US$M**	**Unaudited 2019 US$M**
Net operating cash flows from Continuing operations	1,060	585	2,347
Net operating cash flows from Discontinued operations	—	—	474
Net operating cash flows	**1,060**	**585**	**2,821**
Net investing cash flows from Continuing operations	(1,520)	(1,033)	(944)
Net investing cash flows from Discontinued operations	—	—	(433)
Net investing cash flows	**(1,520)**	**(1,033)**	**(1,387)**
Net financing cash flows from Continuing operations	910	(607)	(10,544)
Net financing cash flows from Discontinued operations	—	—	(13)
Net financing cash flows	**910**	**(607)**	**(10,557)**
Net increase/(decrease) in cash and cash equivalents from Continuing operations	450	(1,055)	(9,141)
Net increase/(decrease) in cash and cash equivalents from Discontinued operations	—	—	18
Proceeds from divestment of Onshore US, net of its cash	—	—	10,427
Cash and cash equivalents, net of overdrafts at the beginning of the financial year	325	1,381	77
Foreign currency exchange rate changes on cash and cash equivalents	1	(1)	—
Cash and cash equivalents, net of overdrafts at the end of the financial year	**776**	**325**	**1,381**

Net operating cash inflows of US$1,060 million in FY2021 increased by US$475 million from FY2020. This reflects higher revenues due to an increase in prices coupled with a decrease in taxes paid.

Net operating cash inflows of US$585 million in FY2020 decreased by US$2,236 million from FY2019. This is primarily due to the divestment of Onshore U.S. and reduced revenue driven by lower prices and volumes in FY20 from continued operations.

Net investing cash outflows of US$1,520 million in FY2021 increased by US$487 million from FY2020. This reflects the investment in an additional 28% working interest in Shenzi of US$480 million, increasing BHP Petroleum's share from 44% to 72%.

Net investing cash outflows of US$1,033 million in FY2020 decreased by US$354 million from FY2019. This primarily relates to the US$443 million divestment of BHP Petroleum's Onshore U.S. assets in FY2019.

Net financing cash inflows of US$910 million in FY2021 increased by US$1,517 million. This reflects a decrease in intercompany finance receivables used to pay down external debt.

Net financing cash outflows of US$607 million in FY2020 decreased by US$9,950 million from FY2019. This relates to a decrease in finance expenses relating to long-term debt repayment and lower interest rates.

3 Other Information

Drilling

The number of wells in the process of drilling and/or completion as of 30 June 2021 was as follows:

	Exploratory wells		Development wells		Total	
	Gross	Net [(1)]	Gross	Net [(1)]	Gross	Net [(1)]
Australia	—	—	—	—	—	—
United States	—	—	27	9	27	9
Other [(2)]	—	—	5	3	5	3
Total	—	—	32	12	32	12

(1) Represents BHP Petroleum's share of the gross well count.
(2) Other is comprised of T&T.

Liquidity and capital resources

BHP Petroleum's policies on debt and liquidity management have the following objectives:

- a strong balance sheet through the cycle; and
- maintain borrowings and excess cash predominantly in U.S. dollars.

Funding Sources

To meet BHP Petroleum's short and long-term liquidity requirements, BHP Petroleum relies primarily on cash generated from operating activities and debt financing from BHP.

At 31 December 2021, BHP Petroleum had cash and cash equivalents of US$992 million (30 June 2021: US$776 million) and long-term debt agreements with BHP of US$10,347 million (30 June 2021: US$10,347 million). The long-term debt agreements balance was recorded as a non-current liability in payables to BHP at 30 June 2021 and was reclassed to a current liability in payables to BHP as it became current at 31 December 2021. At 30 June 2020 and 30 June 2019, BHP Petroleum had cash and cash equivalents of US$325 million and US$1,398 million, respectively, and long-term debt agreements with BHP of US$14,340 million and US$17,340 million, respectively. The non-current portion of the long-term debt agreements as at 30 June 2020 was $10,347 million (30 June 2019: $14,340 million).

BHP Petroleum fulfils its cash management and financing needs through cash from operations and borrowings from BHP, including long-term debt agreements to finance its projects. No new debt was issued in the six months ended 31 December 2021 or during FY2021. These actions enhanced BHP Petroleum's capital structure and extended BHP Petroleum's average debt maturity.

BHP borrowing facilities are not subject to financial covenants. Certain specific financing facilities in relation to specific assets are the subject of financial covenants that vary from facility to facility, as is considered normal for such facilities.

Management believes cash generated by operating activities, along with available borrowing capacity, will be sufficient to support BHP Petroleum's operations for the foreseeable future, as well as short and long-term liquidity requirements.

At 31 December 2021, BHP Petroleum had net amounts payable to BHP of US$1,700 million. Under the terms of the Share Sale Agreement, intra-group funding arrangements are required to be repaid or otherwise eliminated. BHP Petroleum expects to settle intercompany balances with BHP either as a capital injection or loan forgiveness neither of which will involve an outflow of cash in order to satisfy the terms of the Share Sale Agreement. At 31 December 2021, BHP Petroleum does not have any remaining long-term debt obligations.

Capital Requirements

BHP Petroleum's net share of capital development expenditure in the six months ended 31 December 2021, which is presented on a cash basis within this Part, was US$556 million. While the majority of the expenditure for the six months ended 31 December 2021was incurred at its operated Australian, U.S. GOM, and T&T assets, capital expenditure was also incurred by its operating partners at BHP Petroleum's U.S. GOM and Australian non-operated assets. BHP Petroleum's commitments for capital expenditure were US$2,064 million as at 31 December 2021.

On 22 November 2021, BHP Petroleum announced the approval of US$1.5 billion in capital expenditure for development of the Scarborough LNG Project located in the North Carnarvon Basin, Western Australia. The approved capital expenditure represents BHP Petroleum's 26.5% participating interest in Phase 1 of the upstream development. Final Investment Decisions have also been made by Woodside and the Scarborough Joint Venture accounted for at the time of FID.

BHP Petroleum's net share of exploration expenditure in the six months ended 31 December 2021, presented on a cash basis within this section, was US$243 million, of which US$131 million was capitalised. The expenditure is primarily made up of drilling activity in T&T and U.S. GOM.

For leases as at 31 December 2021, BHP Petroleum has current and long-term obligations of US$257 million.

BHP Petroleum's net share of capital development expenditure in FY2021, which is presented on a cash basis within this section, was US$994 million. While the majority of the expenditure in FY2021 was incurred by operating partners at BHP Petroleum's Australian and U.S. GOM non-operated assets, BHP Petroleum also incurred capital expenditure at its operated Australian, U.S. GOM and T&T assets.

Contingent Liabilities

A contingent liability is a possible obligation arising from past events and whose existence will be confirmed only by occurrence or non-occurrence of one or more uncertain future events not wholly within the control of BHP Petroleum. A contingent liability may also be a present obligation arising from past events but is not recognised on the basis that an outflow of economic resources to settle the obligation is not viewed as probable, or the amount of the obligation cannot be reliably measured. The timing and resolution of potential economic outflow relating to BHP Petroleum's contingent liabilities is uncertain. BHP Petroleum's total contingent liabilities for subsidiaries and joint operations as at 31 December 2021 is US$774 million.

Uncertain Tax Matters

BHP Petroleum operates across many tax jurisdictions. Application of tax law can be complex and requires judgement to assess risk and estimate outcomes. The evaluation of tax risks considers both amended assessments received and potential sources of challenge from tax authorities. The status of proceedings for these matters will impact the ability to determine the potential exposure and, in some cases, it may not be possible to determine a range of possible outcomes or a reliable estimate of the potential exposure.

Tax and royalty matters with uncertain outcomes arise in the normal course of business and occur due to changes in tax law, changes in interpretation of tax law, periodic challenges and disagreements with tax authorities and legal proceedings.

Delivery commitments

BHP Petroleum has delivery commitments of natural gas and LNG of approximately 1,070 million Mcf through 2031 and Crude commitments of 8 million barrels through 2024. BHP Petroleum has sufficient proven reserves and production capacity to fulfil these delivery commitments.

BHP Petroleum has obligation commitments of US$33 million for contracted capacity on transportation pipelines and gathering systems through 2025, on which BHP Petroleum is the shipper. The agreements have annual escalation clauses.

4 Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires use of estimates, as well as management's judgements and assumptions regarding matters that are subjective, uncertain or involve a high degree of complexity, all of which affect the results of operations and financial condition for the periods presented. BHP Petroleum believes the following accounting policy is critical to the BHP Petroleum Combined Financial Statements and may involve a higher degree of estimates, judgements and complexity.

Closure and rehabilitation provisions

BHP Petroleum incurs obligations to rehabilitate sites and associated facilities at the end of or, in some cases, during the course of production. BHP Petroleum's largest provisions relate to the cost of removing all unwanted infrastructure associated with an operation and the return of disturbed areas to a safe, stable, productive and self-sustaining condition, consistent with the agreed end land use. The fair value of these obligations are recorded as a liability on a discounted basis. The corresponding cost is capitalised as an asset in the case of operating sites (representing part of the cost of acquiring the future economic benefits of the operation) and reflected as a charge to the income statement for closed sites.

Determining the closure and rehabilitation provision is a complex area requiring significant judgement and estimates, particularly given the timing and long timescale of cash flows, extent of costs associated with future rehabilitation activities, legislative requirements in the applicable jurisdiction, changes to the regulatory environment and the applicable discount rates used.

Reserves

Reserves are estimates of the amount of product that can be demonstrated to be able to be economically and legally extracted from BHP Petroleum's properties. In order to estimate reserves, assumptions are required about a range of technical and economic factors, including quantities, qualities, production techniques, recovery efficiency, production and transport costs, commodity supply and demand, commodity prices and exchange rates.

Estimating the quantity and/or quality of reserves requires the size, shape and depth or oil and gas reservoirs to be determined by analysing geological data, such as drilling samples and geophysical survey interpretations. Economic assumptions used to estimate reserves change from period to period as additional technical and operational data is generated. This process may require complex and difficult geological judgements to interpret the data.

Reserve impact on financial reporting

Estimates of reserves may change from period to period as the economic assumptions used to estimate reserves change and additional geological data is generated during the course of operations. Changes in reserves may affect BHP Petroleum's financial results and financial position in a number of ways, including:

- asset carrying values may be affected due to changes in estimated future production levels;
- depreciation, depletion and amortisation charged in the income statement may change where such charges are determined on the units of production basis or where the useful economic lives of assets change;
- closure and rehabilitation provisions may change where changes in estimated reserves affect expectations about the timing or cost of these activities; and
- the carrying amount of deferred tax assets may change due to changes in estimates of the likely recovery of the tax benefits.

Property, Plant and Equipment

Depreciation

The depreciation method and rates applied to specific assets reflect the pattern in which the asset's benefits are expected to be used by BHP Petroleum. The proved reserves for petroleum assets are used to determine units of production depreciation unless doing so results in depreciation charges that do not reflect the asset's useful life. Where this occurs, alternative approaches to determining reserves are applied, such as using management's expectations of future oil and gas prices rather than yearly average prices to provide a phasing of periodic depreciation charges that better reflects the asset's expected useful life.

Exploration and evaluation

Exploration and evaluation expenditure results in certain items of expenditure being capitalised for an area of interest where a judgement is made that it is likely to be recoverable by future exploitation or sale, or where the activities are judged not to have reached a stage that permits a reasonable assessment of the existence of reserves.

Management makes certain estimates and assumptions as to future events and circumstances, in particular when making a quantitative assessment of whether an economically viable extraction operation can be established. These estimates and assumptions may change as new information becomes available. If, after having capitalised the expenditure under the policy, new information suggests that recovery of the expenditure is unlikely, the relevant capitalised amount is charged to the income statement.

Impairments

Assessment of indicators of impairment or impairment reversal requires significant management judgement. Indicators of impairment may include changes in BHP Petroleum's operating and economic assumptions, including those arising from changes in reserves, updates to the commodity supply, demand and price forecasts, or the possible additional impacts from emerging risks such as those related to climate change and the transition to a lower carbon economy and pandemics similar to COVID-19.

The most significant estimates impacting BHP Petroleum's recoverable amount determinations include but are not limited to:

- Commodity prices;
- Future production volumes;
- Operating costs and capital expenditures; and
- Selection of appropriate discount rates.

Deferred Tax

Judgement is required to determine the amount of deferred tax assets that are recognised based on the likely timing and the level of future taxable profits. Judgement is applied in recognising deferred tax liabilities arising from temporary differences in investments.

BHP Petroleum assesses the recoverability of recognised and unrecognised deferred taxes, on a consistent basis. Estimates and assumptions relating to projected earnings and cash flows as applied in BHP Petroleum's impairment process are used for operating assets.

5 Future Accounting Pronouncements

A number of accounting standards and interpretations have been issued and will be applicable in future periods. While these remain subject to ongoing assessment, no significant impacts have been identified to date. These standards have not been applied in the preparation of the BHP Petroleum Combined Financial Statements.

Part 19 – Depositary Interests

1 Depositary Interests, for the settlement of transactions within CREST

Woodside has established arrangements to enable investors to settle interests in the Woodside Shares through the CREST system on Admission. CREST is a paperless settlement system allowing securities to be transferred from one person's CREST account to another without the need to use share certificates or written instruments of transfer. Securities issued by non-UK companies, such as Woodside, cannot be held directly or transferred electronically in the CREST system. However, Depositary Interests allow those securities to be dematerialised and settled electronically through CREST. Where investors choose to settle interests in the Woodside Shares through the CREST system, and pursuant to depositary arrangements established by Woodside, the Custodian will hold the Woodside Shares and issue dematerialised Depositary Interests representing the underlying Woodside Shares, which will be held on trust for the holders of the Depositary Interests. The Depositary Interests will be independent securities constituted under English law which may be held and transferred through the CREST system. Investors should note that it is the Woodside Shares which will be admitted to trading on the LSE and that it is the Depositary Interests which are transferred for the settlement of those trades through CREST.

The Woodside Constitution is consistent with CREST membership in respect of Depositary Interests and the holding and transfer of Depositary Interests in uncertified form. Under the Corporations Act, companies are not prohibited from issuing shares in book-entry form but shareholders have the right to require the companies to issue physical certificates.

Woodside and the UK Depositary will enter into a UK depositary agreement on or around Admission, the principal terms of which are summarised below.

The Depositary Interests will be created pursuant to, and issued on the terms of, a deed poll that will be executed prior to Admission by the UK Depositary in favour of the holders of the Depositary Interests from time to time. Holders of Depositary Interests should note that they will have no rights against Euroclear UK & International Limited (the operators of CREST) or its subsidiaries in respect of the underlying Woodside Shares or the Depositary Interests representing them.

If a holder of Woodside Shares so requests, its Woodside Shares will be transferred to an account of the UK Depositary or its nominated custodian and the UK Depositary will issue Depositary Interests to participating CREST members.

Each Depositary Interest will be treated as one Woodside Share for the purposes of determining, for example, eligibility for any dividends. The UK Depositary will pass on to holders of Depositary Interests any share or cash benefits received by it as holder of Woodside Shares on trust for the Depositary Interest Holder. Depositary Interest Holders, through the UK Depositary, will also be able to receive notices of meetings of holders of Woodside Shares and other notices issued by Woodside to its shareholders.

The Depositary Interests have the same security code (ISIN) as the underlying Woodside Shares and will not require a separate admission to the Main Market. The Woodside Shares can then be traded on the LSE, and settled within the CREST system in the form of Depositary Interests, in the same way as any other CREST securities. Application will be made for the Depositary Interests to be admitted to CREST with effect from Admission.

If a holder wishes to cancel its Depositary Interest, it will either directly or through its broker instruct the applicable CREST participant to initiate a CREST withdrawal (where that withdrawal is sent to the UK Depositary) for the name that appears on the Register. The Depositary Interest will then be cancelled by the UK Depositary and the related Woodside Shares will be transferred to the account of a nominated CHESS participant or to an issuer sponsored account on the Woodside Register by the Woodside Share Registry. The Woodside Shareholder will then be sent a holding statement reflecting the receipt by them of the underlying Woodside Shares.

The information included within Part 19 *(Depositary Interests)* of this Prospectus relating to the obtaining and cancellation of Depositary Interests by a holder is intended to be a summary only and is not to be construed as legal, business or tax advice. Each investor should consult their own lawyer, financial adviser, broker or tax adviser for legal, financial or tax advice in relation to Depositary Interests.

Deed Poll

The Deed Poll executed by the UK Depositary prior to Admission contains the following provisions:

The UK Depositary will hold (itself or through the Custodian), as bare trustee, the underlying Woodside Shares and all and any rights and other securities, property and cash attributable to the underlying Woodside Shares pertaining to the Depositary Interests for the benefit of the holders of the relevant Depositary Interests as tenants in common. The UK Depositary will re-allocate securities or Depositary Interests distributions allocated to the UK Depositary or Custodian pro rata to the Woodside Shares held for the respective accounts of the holders of Depositary Interests but will not be required to account for fractional entitlements arising from that re-allocation.

Holders of Depositary Interests agree to give any warranties and certifications to the UK Depositary as the UK Depositary may reasonably require. In particular, holders of Depositary Interests warrant, among other things, that the securities in Woodside transferred or issued to the UK Depositary or Custodian on behalf of the UK Depositary for the account of the Depositary Interest Holder are free and clear of all liens, charges, encumbrances or third party interests and that those transfers or issues are not in contravention of the Woodside Constitution or any contractual obligation, or applicable law or regulation binding or affecting that holder, and holders of Depositary Interests agree to indemnify the UK Depositary against any liability incurred as a result of any breach of that warranty.

The UK Depositary and any Custodian will pass on to the Depositary Interest Holders and, so far as they are reasonably able, exercise on behalf of the Depositary Interest Holders all rights and entitlements received or to which they are entitled in respect of the underlying Woodside Shares which are capable of being passed on or exercised. Rights and entitlements to cash distributions, to information, to make choices and elections and to call for, attend and vote at meetings will, subject to the Deed Poll, be passed on in the form in which they are received, together with amendments and additional documentation necessary to effect the passing-on, or, as the case may be, exercised in accordance with the Deed Poll. If arrangements are made which allow a holder to take up rights in Woodside's securities requiring further payment, the holder must put the UK Depositary in cleared funds before the relevant payment date or other date notified by the UK Depositary if it wishes the UK Depositary to exercise those rights.

The UK Depositary will be entitled to cancel Depositary Interests and treat the holders of them as having requested a withdrawal of the underlying securities in certain circumstances, including where a Depositary Interest Holder fails to furnish to the UK Depositary with any certificates or representations as to material matters of fact, including their identity, as the UK Depositary deems appropriate.

The UK Depositary warrants that it is an authorised person under the FSMA and is duly authorised to carry out custodian and other activities under the Deed Poll. It also undertakes to maintain that status and authorisation.

The Deed Poll contains provisions excluding and limiting the UK Depositary's liability. For example, the UK Depositary will not be liable to any Depositary Interest Holder or any other person for liabilities in connection with the performance or non-performance of obligations under the Deed Poll or otherwise except as may result from its negligence, wilful default or fraud or that of any person for whom it is vicariously liable, provided that the UK Depositary will not be liable for the negligence, wilful default or fraud of any Custodian or agent which is not a member of its group unless it has failed to exercise reasonable care in the appointment and continued use and supervision of that Custodian or agent. Except in the case of personal injury or death, any liability incurred by the UK Depositary to a holder under the Deed Poll is limited to the lesser of:

- the value of the Woodside Shares that would have been properly attributable to the Depositary Interests to which the liability relates; and
- that proportion of £5 million which corresponds to the portion which the amount the UK Depositary would otherwise be liable to pay to the holder bears to the aggregate of the amounts the UK Depositary would otherwise be liable to pay to all of those holders in respect of the same act, omission or event which gave rise to that liability or, if there are no amounts of that type, £5 million.

The UK Depositary is entitled to charge holders of Depositary Interests fees and expenses for the provision of its services under the Deed Poll.

Each holder of Depositary Interests is liable to indemnify the UK Depositary and any Custodian (and their agents, officers and employees), and hold each of them harmless, from and against all liabilities arising from or incurred in connection with, or arising from any act related to, the Deed Poll so far as they relate to the property held for the account of that holder, other than those caused by or resulting from the wilful default, negligence or fraud of: (i) the UK Depositary; or (ii) the Custodian or any agent if that Custodian or agent is a member of the UK Depositary's group or if, not being a member of the same group, the UK Depositary will have failed to exercise reasonable care in the appointment and continued use of that Custodian or agent.

The Depositary is entitled to make deductions from the deposited property or any income or capital arising from it, or to sell any deposited property and make deductions from the sale proceeds of it, in order to discharge the indemnification obligations of Depositary Interest Holders.

The UK Depositary may terminate the Deed Poll by giving not less than 90 days' notice. During that notice period, Depositary Interest Holders may cancel their Depositary Interests and withdraw their deposited property and, if any Depositary Interests remain outstanding after termination, the UK Depositary will, as soon as reasonably practicable and amongst other things: (i) deliver the deposited property in respect of the Depositary Interests to the relevant Depositary Interest Holder; or at the UK Depositary's discretion; (ii) sell all or part of that deposited property. It will, as soon as reasonably practicable, deliver the net proceeds of any sale, after deducting any sums due to the UK Depositary, together with any other cash held by it under the Deed Poll, pro rata to the Depositary Interest Holders in respect of their Depositary Interests.

The Depositary or Woodside may require from any holder: (i) information as to the capacity in which Depositary Interests are owned or held by any holders and the identity of any other person with any interest of any kind in those Depositary Interests or the underlying Woodside Shares and the nature and amounts of those interests; (ii) evidence or declaration of nationality or residence of the legal or beneficial owner(s) of Depositary Interests and any information as is required to transfer the relevant Depositary Interests or Woodside Shares to the holder; and (iii) any information as is necessary or desirable for the purposes of the Deed Poll or CREST system, and holders are bound to provide any information requested. The holders of Depositary Interests consent to the disclosure of that information by the Depositary, Custodian or Woodside to the extent necessary or desirable to comply with their respective legal or regulatory obligations.

Furthermore, to the extent that the Woodside Constitution, or any applicable laws or regulations, the Ground Rules for the Management of the FTSE UK Index Series (if applicable), or any court or legal or regulatory authority may require or Woodside deems it necessary or desirable in connection with (including in response to requests for information), the disclosure to Woodside of, or limitations in relation to, beneficial or other ownership of, or interests of any kind whatsoever in Woodside's securities, the UK Depositary Interest Holders are to comply with those provisions and with Woodside's securities, the Depositary Interest Holders are to comply with those provisions and with Woodside's instructions with respect to them, and consent to the disclosure of that information for those purposes.

Holders of Depositary Interests may not have the opportunity to exercise all of the rights and entitlements available to holders of Woodside Shares, including, for example, the ability to vote on a show of hands. In relation to voting, it will be important for holders of Depositary Interests to give prompt instructions to the UK Depositary or its nominated Custodian, in accordance with any voting arrangements made available to them, to vote the underlying Woodside Shares on their behalf or, to the extent possible, to take advantage of any arrangements enabling holders of Depositary Interests to vote those Woodside Shares as a proxy of the UK Depositary or its nominated Custodian.

UK Depositary Agreement

The UK Depositary Agreement entered into between Woodside and the UK Depositary prior to Admission contains the following provisions:

Under the UK Depositary Agreement, Woodside appoints the UK Depositary to constitute and issue from time to time, upon the terms of the Deed Poll, a series of Depositary Interests representing Woodside Shares and to provide certain other services (including depositary services, custody services and dividend services) in connection with those Depositary Interests.

The UK Depositary agrees that it will comply with the terms of the Deed Poll and that it will perform its obligations with reasonable skill and care. The UK Depositary assumes certain specific obligations, including, for example, to arrange for the Depositary Interests to be admitted to CREST as participating securities and provide copies of, and access to, the register of Depositary Interests.

Woodside acknowledges that it will be its responsibility and undertakes to advise the UK Depositary promptly of any securities laws or other applicable laws, rules or regulations in the state of Victoria, Australia with which the UK Depositary must comply in providing the services.

Woodside agrees to provide any assistance, information and documentation to the UK Depositary as is reasonably required by the UK Depositary for the purposes of performing its duties, responsibilities and obligations under the UK Depositary Agreement.

The UK Depositary indemnifies Woodside and its officers and employees from and against any loss (excluding indirect, consequential or special loss) which any of them may incur in any way as a result of or in connection with the fraud, negligence or wilful default of the UK Depositary (or its officers, employees, agents or sub-contractors).

Subject to any earlier termination, the appointment of the UK Depositary will continue until 15 December 2023 and thereafter for a fixed period of two years and then until terminated in accordance with the terms of the UK Depositary Agreement. Should the UK Depositary Agreement be terminated for any reason, other than arising from the UK Depositary's fraud, negligence, wilful default or material breach of a term of the UK Depositary Agreement, Woodside will within 30 days of termination pay to the UK Depositary the UK Depositary's reasonable costs and expenses of transferring the Depositary Interest register to its new registrar. Either party may terminate the UK Depositary Agreement by giving not less than 6 months' notice in writing. Either party may terminate the UK Depositary Agreement with immediate effect by notice in writing if the other party: (i) will be in persistent or material breach of any material term (of the UK Depositary Agreement) and that breach is not remedied within 21 days of a request for that remedy; (ii) goes into insolvency or liquidation or administration or a receiver is appointed over any part of its undertaking or assets, subject to certain provisos; or (iii) will cease to have the appropriate authorisations which permit it lawfully to perform its obligations under the UK Depositary Agreement.

The UK Depositary will be entitled to employ agents for the purposes of carrying out certain of its obligations under the UK Depositary Agreement which the UK Depositary reasonably considers to be of a specialist nature.

Woodside is to pay to the UK Depositary an annual fee for the services. Woodside will pay a fixed fee for the deposit, cancellation and transfer of the Depositary Interests and the compilation of the initial Depositary Interests register. Woodside will in addition reimburse the UK Depositary within 30 days of the UK Depositary's invoice for all network charges, CREST charges, money transmission and banking charges and other out-of-pocket expenses incurred by it in connection with the provision of the services under the UK Depositary Agreement.

Woodside will indemnify the UK Depositary from and against all loss suffered by the UK Depositary as a result of or in connection with the performance of its obligations under the UK Depositary Agreement.

The aggregate liability of the UK Depositary to Woodside over any 12-month period under the UK Depositary Agreement will not exceed twice the amount of the Fees (as defined in the UK Depositary Agreement) payable in any 12-month period in respect of a single claim or in the aggregate.

Corporate Sponsored Nominee ("CSN") agreement

Woodside has arranged for Computershare UK (through its appointed nominee, UK Nominee), to hold Depositary Interests representing Woodside Shares for holders of BHP depositary interests through the existing BHP CSN. This arrangement is designed to enable such Shareholders to hold their entitlement to Woodside Shares in a form that can be traded on the LSE.

Under the CSN Agreement, Computershare UK has agreed to provide registrar services including maintaining records of participants in the CSN Facility, issuing statements of ownership, providing online access to enable participants to view their holdings, processing electronic instructions on their behalf, providing proxy services, processing distributions and providing a dealing facility.

The CSN Agreement includes limitations and exclusions of the UK Nominee's liability, mutual indemnities and provision for the payment of fees and expenses to Computershare UK.

Summary of the principal CSN terms and conditions

Through UK Nominee Computershare UK will hold Depositary Interests for CSN Participants on the CSN Terms and Conditions. Under the CSN Terms and Conditions, CSN Participants are the beneficial owners of the

Depositary Interests to which they relate and may give instructions to transfer the Depositary Interests or underlying Woodside Shares. By participating in the CSN Facility, CSN Participants agree that they will not pledge or charges the Depositary Interests and agree to not give any other person rights or benefits over their Depositary Interests.

Computershare UK agrees to pass on company communications and act on CSN Participants' instructions to exercise voting and other rights in relation to their underlying Woodside Shares (provided that it is put in funds if it is required to make any payment) and to take all reasonable steps to treat CSN Participants, so far as possible, in the same way as a registered holder of Woodside Shares.

UK Nominee, through Computershare UK, is appointed as agent for the CSN Participants to give CREST instructions. Neither Computershare UK nor UK Nominee are responsible for losses incurred from acts or omissions of third parties (including, but not limited to, CREST). CSN Participants are required to indemnify Computershare UK for all losses and expenses which may arise from the failure to give Computershare UK sufficient funds to carry out the CSN Participant's instructions, the CSN's breach of the CSN Terms or any taxes paid on CSN participants behalf arising out of their use of the CSN Facility.

Client money held on behalf of CSN Participants will be held in pooled accounts. Computershare UK will be entitled to set off amounts it owes to a CSN Participant against any amounts owed to it by that CSN Participant. Computershare UK may make deductions in respect of any applicable withholding tax from payments due to a CSN Participant.

Computershare UK may terminate a CSN Participant's participation in the CSN Facility if the CSN Participant breaches the CSN Terms and Conditions, in which case, Computershare UK will instruct the transfer of the underlying Depositary Interests or Woodside Shares to an account nominated by the CSN Participant.

No charges are payable by a CSN Participant other than for services requested by that CSN Participant.

CSN Participants may be required to provide information in relation to their underlying holdings of Depositary Interests on the same basis as such information may be required from a holder of Woodside Shares.

The CSN Terms and Conditions do not restrict a participant's rights under the rules of the Financial Conduct Authority.

The CSN Terms and Conditions are governed by English law.

The CSN Terms and Conditions are available on the Woodside website.

Termination and your right to cancel your participation in the CSN Facility

A CSN Participant may cancel their participation in the CSN Facility by giving Computershare UK written notice within 14 days after normal trading in Woodside Shares commences on the LSE. If a CSN Participant cancels their participation in the CSN Facility, Computershare UK will transfer the underlying Depositary Interests or Woodside Shares to such person as the CSN Participant may nominate and no fees will be charged for such transfer.

Thereafter, a CSN Participant may terminate their participation in the CSN Facility, and a transfer fee and any taxes associated with the withdrawal will apply.

Participation in the CSN Facility is limited to Shareholders in certain jurisdictions

The ability to participate in the CSN Facility may be restricted or made onerous by law in certain jurisdictions. Any Shareholder who has a registered address in a CSN Restricted Jurisdiction will not be entitled to participate in the CSN Facility.

Instead, such Shareholders will be issued their Woodside Shares on the Australian issuer sponsored subregister, with an issuer sponsored holding statement issued reflecting their Woodside shareholding.

Computershare UK will provide a dealing service for CSN Participants. Details of this service are available on the Woodside website.

Movement between the Company's Share and Depositary Interest registers

Subject to the further information outlined below, following Admission, Woodside Shareholders on the Woodside Register will be able to request to have their Shares converted into Depositary Interests in the UK, or vice versa, by contacting Computershare's Global Transaction team in the respective region. Conversions between the two registers are usually completed within 24 hours, depending on the time of lodgement, allowing for time differences and business days in the respective jurisdictions. Cross-border market transaction fees may be charged by any intermediaries.

Moving holdings from Depositary Interests held through the CSN Facility (in the UK) to another UK custodian or broker within CREST

Holders can withdraw from the CSN Facility at any time by completing a CSN Facility withdrawal form (available on request from Computershare UK). If holders wish instead to have their securities held through another UK custodian or broker within CREST the holder must make arrangements, as well as completing the CSN Facility withdrawal form with the UK custodian or broker to agree a matching trade and settlement date with Computershare UK.

Further details in relation to options can be found on the CSN Facility withdrawal form.

To convert holdings from Depositary Interests held through CREST (in the UK) to Woodside Shares held in Australia

Holders will need to submit a Depositary Interest withdrawal instruction to Computershare's Global Transaction team in the UK specifying the account through which they wish to hold the Woodside Shares in Australia. Holders with a custodian or broker account should contact their custodian or broker for assistance.

To convert Woodside Shares into the form of Depositary Interests held through CREST (in the UK)

Holders would first need to engage a suitable UK custodian or broker who is able to trade on the LSE, and who is able to hold and settle Depositary Interests through CREST. Once this arrangement is established, the holder would request their custodian or broker to deliver their Woodside Shares to the Australian custodian of Computershare UK, and submit a Depositary Interest issuance instruction to Computershare's Global Transactions team in Australia.

To convert from holding Woodside ADSs to Woodside Shares

Woodside ADS holders will be entitled to present Woodside ADSs to the Citibank, N.A., the depositary for the Woodside ADSs, for cancellation and then receive the corresponding number of underlying Woodside Shares represented by the surrendered Woodside ADSs at the offices of the custodian, Citicorp Nominees Pty Limited, located at Level 15, 120 Collins Street, Melbourne VIC 30000 (subject in all cases to any restrictions on cancellation or withdrawal that the Woodside depositary may impose from time to time, to payment of taxes and applicable Woodside depositary fees and expenses, and to the provisions of the deposit agreement between Woodside and Citibank, N.A., for the Woodside ADSs). Any withdrawal must also be done in accordance with the procedures of the holder's bank, broker, other financial institution or other DTC participant.

Receipt of dividends

If the way in which a Woodside Shareholder holds their Woodside Shares following Admission permits an election, they will continue to have dividends paid in the currency they have elected prior to Admission.

However, if a Woodside Shareholder has not elected a particular currency prior to Admission or their election is no longer permitted, the way in which they hold their Woodside Shares following Admission will determine the currency in which they receive any dividends.

Holders of Depositary Interest held through CREST

Holders will have amounts in respect of dividends declared by the Company in USD paid to them in Pounds Sterling by default, with the option to receive payments in USD.

Holders of Depositary Interests held through the CSN Facility

Holders will have amounts in respect of dividends declared by the Company in USD paid to them in Pounds Sterling, with the option to receive USD in accordance with the terms and conditions of the CSN Facility.

Holders of Limited Shares on the Limited Share Register in Australia

Holders will have amounts in respect of dividends declared by the Company in USD paid to them in AUD unless their registered address is i) in the United Kingdom, where they will be paid their dividend in GBP, or ii) in the United States, where they will be paid their dividend in US dollars, or iii) in New Zealand, where they will be paid their dividend in NZD.

Shareholders who reside outside of the United States can elect to receive their dividend in USD, payable into a US financial institution account.

Mandatory direct credit applies for all holders with a registered address within Australia, New Zealand, the United Kingdom and the United States.

The Woodside dividend reinvestment plan provides eligible shareholders with a convenient opportunity to reinvest all or part of their dividends to obtain additional Woodside Shares without having to pay brokerage, commission, or other transaction costs to Woodside in respect of shares issued under the dividend reinvestment plan. Shareholders with registered addresses in Australia and New Zealand can elect to participate in the dividend reinvestment plan.

New Woodside ADS Holders

The procedures governing the payment of dividends to Limited ADS holders are governed by the terms of the Limited ADS Deposit Agreement.

Part 20 – Taxation

The information set out below describes the principal UK, Australian and US tax consequences of the acquisition, holding and disposal of the Woodside Shares and is included for general information only. It is not intended to be, nor should it be construed to be, legal or tax advice to any prospective investors. This section does not take into account the individual circumstances of any prospective investors and should not be relied upon by any prospective investor or any other person. Each prospective investor should obtain, and only rely upon, their own professional tax advice regarding the tax consequences of acquiring, holding and disposing of the Woodside Shares under the laws of their country and/or state of citizenship, domicile or residence. This summary is based on tax legislation in force as at the Last Practicable Date, without prejudice to any amendments introduced at a later date and implemented with retroactive effect.

1. UK Taxation

a) Material UK tax considerations

The following statements are intended as a general guide to certain UK tax considerations only, do not purport to be a complete analysis of all potential UK tax consequences of acquiring, holding and/or disposing of Woodside Shares and Depositary Interests and do not constitute legal or tax advice. The following statements are based on UK tax law (including case law) and what is understood to be the current published practice of HMRC as at the Last Practicable Date, both of which may change, possibly with retrospective effect.

Except where expressly stated otherwise, the following statements apply only to Woodside Shareholders, Eligible BHP Shareholders and Depositary Interest Holders who are resident (and in the case of individual Woodside Shareholders, Eligible BHP Shareholders and Depositary Interest Holders, resident and domiciled) solely in the UK for tax purposes, who hold their Woodside Shares, BHP Shares or Depositary Interests respectively as an investment (otherwise than under an individual savings account or pension arrangement), and who are the beneficial owners of their Woodside Shares, BHP Shares or Depositary Interests respectively and any dividends paid in respect of them. The statements further assume that the holders of the Depositary Interests are the beneficial owners of the underlying Woodside Shares.

The following statements do not take into account the tax positions of certain categories of Woodside Shareholders, Eligible BHP Shareholders and Depositary Interest Holders who are subject to special rules (such as persons acquiring Woodside Shares or Depositary Interests in connection with any employment, dealers in securities, insurance companies, trustees and collective investment schemes). Nor do the following statements consider the tax position of: (i) any person holding investments in any HMRC-approved arrangements or schemes (including, but not limited to, the enterprise investment scheme, the venture capital scheme or the seed enterprise investment scheme), (ii) any person able to claim any inheritance tax reliefs, or (iii) any non-UK resident Woodside Shareholder, Eligible BHP Shareholder or Depositary Interest Holder holding Woodside Shares, BHP Shares or Depositary Interests respectively in connection with a trade, profession or vocation carried on in the UK (whether through a branch or agency or, in the case of a corporate Woodside Shareholder, Eligible BHP Shareholder, or a Depositary Interest Holder, a permanent establishment or otherwise).

ELIGIBLE BHP SHAREHOLDERS, WOODSIDE SHAREHOLDERS OR DEPOSITARY INTEREST HOLDERS OR PROSPECTIVE WOODSIDE SHAREHOLDERS OR DEPOSITARY INTEREST HOLDERS WHO ARE IN ANY DOUBT ABOUT THEIR TAX POSITION SHOULD CONSULT THEIR PROFESSIONAL TAX ADVISERS.

b) Implementation and receipt by Eligible BHP Shareholders of New Woodside Shares

Income tax

The Special Dividend should give rise to dividend income for UK income tax purposes equal to the market value on the date of the transfer of New Woodside Shares to Eligible BHP Shareholders of the New Woodside Shares to which they are entitled.

The general tax treatment of dividend income for UK tax purposes is as is as follows:

- all dividend income received by such a Shareholder will form part of the Shareholder's total income for income tax purposes and will represent the highest part of that income;

- a nil rate of income tax applies to the first £2,000 of taxable dividend income received by such Shareholder in a tax year (the "**Nil Rate Amount**"), regardless of what tax rate would otherwise apply to that dividend income;
- where an individual Eligible BHP Shareholder's taxable dividend income for a tax year exceeds the Nil Rate Amount, the excess amount (the "**Relevant Dividend Income**") will be subject to income tax;
- at the rate of 8.75%, to the extent that the Relevant Dividend Income falls below the threshold for the higher rate of income tax;
- at the rate of 33.75%, to the extent that the Relevant Dividend Income falls above the threshold for the higher rate of income tax but below the threshold for the additional rate of income tax; and
- at the rate of 39.35%, to the extent that the Relevant Dividend Income falls above the threshold for the additional rate of income tax.

In determining whether and, if so, to what extent the Relevant Dividend Income falls above or below the threshold for the higher rate of income tax or, as the case may be, the additional rate of income tax, the Eligible BHP Shareholder's total taxable income for the tax year in question (including the part within the Nil Rate Amount) will, as noted above, be treated as the highest part of the Shareholder's total income for income tax purposes.

Corporation tax on income

Eligible BHP Shareholders within the charge to UK corporation tax which are 'small companies' for the purposes of UK taxation of dividends will not generally be subject to UK tax on the Special Dividend.

Other Eligible BHP Shareholders within the charge to UK corporation tax will not be subject to tax on the Special Dividend so long as the Special Dividend falls within an exempt class and certain other conditions (including anti-avoidance conditions) are met. An example of such an exempt class of dividends would include dividends paid to a person holding less than 10% of the issued share capital of the payer (or, if there is more than one class of share, the same class of that share capital in respect of which the dividend is paid) and who is entitled to less than 10% of the profits available for distribution to holders of the same class of share and would be entitled to less than 10% of the assets available for distribution to holders of that same class of share on a winding-up.

*UK Capital gains tax ("**CGT**") and UK corporation tax on chargeable gains*

For the purpose of UK CGT and UK corporation tax on chargeable gains, an Eligible BHP Shareholder will have a base cost in their New Woodside Shares equal to the market value of the New Woodside Shares at the time of the transfer of New Woodside Shares to Shareholders. The Special Dividend should not give rise to a disposal of an Eligible BHP Shareholder's BHP shares nor a reduction in their existing base cost therein.

c) Holding of the shares

Dividends on Woodside Shares

Woodside Shareholders and Depositary Interest Holders within the charge to UK income tax

The general tax treatment of dividends paid by the company on Woodside Shares to Woodside Shareholders or Depositary Interest Holders who are within the charge to UK income tax on such dividends is as follows:

- all dividends received by such a Woodside Shareholder or a Depositary Interest Holder will form part of the Woodside Shareholder's or Depositary Interest Holder's total income for income tax purposes and will represent the highest part of that income;
- a nil rate of income tax applies to the first £2,000 of taxable dividend income received by such Woodside Shareholder or Depositary Interest Holder in a tax year (the "**Nil Rate Amount**"), regardless of what tax rate would otherwise apply to that dividend income;
- where an individual Woodside Shareholder's or Depositary Interest Holder's taxable dividend income for a tax year exceeds the Nil Rate Amount, the excess amount (the "**Relevant Dividend Income**") will be subject to income tax;

- at the rate of 8.75%, to the extent that the Relevant Dividend Income falls below the threshold for the higher rate of income tax;
- at the rate of 33.75%, to the extent that the Relevant Dividend Income falls above the threshold for the higher rate of income tax but below the threshold for the additional rate of income tax; and
- at the rate of 39.35%, to the extent that the Relevant Dividend Income falls above the threshold for the additional rate of income tax.

In determining whether and, if so, to what extent the Relevant Dividend Income falls above or below the threshold for the higher rate of income tax or, as the case may be, the additional rate of income tax, the Woodside Shareholder's or Depositary Interest Holder's total taxable income for the tax year in question (including the part within the Nil Rate Amount) will, as noted above, be treated as the highest part of the Woodside Shareholder's or Depositary Interest Holder's total income for income tax purposes.

Woodside Shareholders and Depositary Interest Holders within the charge to UK corporation tax

Woodside Shareholders and Depositary Interest Holders within the charge to UK corporation tax which are "small companies" (for the purposes of UK taxation of dividends) will not generally be subject to tax on dividends received from the company.

Other Woodside Shareholders and Depositary Interest Holders within the charge to UK corporation tax will not be subject to tax on dividends from the company so long as the dividends fall within an exempt class and certain other conditions (including anti-avoidance conditions) are met. An example of such an exempt class of dividends would include dividends paid to a person holding less than 10% of the issued share capital of the payer (or, if there is more than one class of share, the same class of that share capital in respect of which the dividend is paid) and who is entitled to less than 10% of the profits available for distribution to holders of the same class of share and would be entitled to less than 10% of the assets available for distribution to holders of that same class of share on a winding-up.

Withholding tax in Australia

The Australian withholding tax consequences of dividends paid to UK resident Woodside Shareholders and Depositary Interest Holders are outlined at paragraph 2 of this Part 20.

If Australian dividend withholding tax is payable on dividends from the company, UK resident Woodside Shareholders and Depositary Interest Holders should seek their own tax advice to determine the Australian and UK taxation implications.

Sale of Woodside Shares

Woodside Shareholders and Depositary Interest Holders within the charge to CGT

A disposal or deemed disposal of Woodside Shares or Depositary Interests by an individual Woodside Shareholder or Depositary Interest Holder may give rise to a chargeable gain (or allowable loss) for the purposes of CGT, depending on the circumstances and subject to any available exemption or relief. The CGT annual exemption (which is £12,300 for individuals in the 2022-23 tax year) will be available to exempt any chargeable gain, to the extent it has not already been utilised by the individual Woodside Shareholder or Depositary Interest Holder.

UK CGT will generally be charged at 10% (for tax year 2022-23) to the extent that the total chargeable gains and, generally, total taxable income arising in a tax year, after all allowable deductions (including losses, the income tax personal allowance and the capital gains tax annual exempt amount), fall below the threshold for higher rate of income tax for the tax year. To the extent that any chargeable gains (or part of any chargeable gains) arising in a tax year exceed the threshold for the higher rate of income tax when aggregated with any such income (in the manner referred to above), CGT will generally be charged at 20% (for tax year 2022-23).

Woodside Shareholders and Depositary Interest Holders within the charge to UK corporation tax

A disposal or deemed disposal of Woodside Shares or Depositary Interests may give rise to a chargeable gain (or allowable loss) for the purposes of UK corporation tax (the current rate of which is 19%, however rising to 25% from 1 April 2023 for companies with profits exceeding £250,000), depending on the circumstances and subject to any available exemption or relief.

Australian CGT consequences

Australian CGT consequences of disposals of Woodside Shares or Depositary Interests by UK resident Woodside Shareholders and Depositary Interest Holders are outlined at paragraph 2 of this Part 20. If any tax is payable in Australia on a gain accruing on the disposal of Woodside Shares or Depositary Interests, UK resident Woodside Shareholders and Depositary Interest Holders should seek their own tax advice to determine the Australian and UK taxation implications.

UK Stamp Duty and Stamp Duty Reserve Tax ("SDRT")

The following statements about UK stamp duty and SDRT apply regardless of whether or not a Woodside Shareholder or Depositary Interest Holder is resident, domiciled or deemed domiciled in the UK or elsewhere, and are intended as a guide only to the general UK stamp duty and SDRT position and do not apply to persons such as brokers, dealers or intermediaries in respect of purchases of securities in specified circumstances.

d) No liability to UK stamp duty or SDRT should arise on the issuance of Woodside Shares or Depositary Interests.

A transfer of a Depositary Interest, which will be effected on a paperless basis within CREST, should not be subject to UK stamp duty on the basis that there will not be a written instrument of transfer, and should not be subject to SDRT, provided that:

- Woodside is incorporated outside of the UK and its central management and control is and will continue to be exercised outside of the UK;
- the Woodside Shares are not, and will not be, registered in a register kept in the UK by or on behalf of Woodside; and
- the Woodside Shares are, and will continue to be, listed on a recognised stock exchange (such as the ASX).

UK stamp duty will in principle be payable on any instrument of transfer of Woodside Shares which is executed in the UK or which relates to any property situated, or any matter or thing done or to be done, in the UK. In practice, no stamp duty should be required to be paid on any instrument transferring Woodside Shares. Any agreement to transfer Woodside Shares should also not be subject to SDRT provided that the Woodside Shares are not registered in any register kept in the UK or paired with shares issued or raised by a company incorporated in the UK.

2. Australian Taxation

Set out below is a summary of the Australian income tax, goods and services tax ("**GST**") and stamp duty implications of the Implementation and holding New Woodside Shares for Woodside Shareholders who:

- are also Eligible BHP Shareholders;
- are residents of Australia for Australian income tax purposes or non-residents of Australia for Australian income tax purposes who do not hold BHP Shares, and Woodside Shares (including New Woodside Shares), through a permanent establishment in Australia; and
- hold their BHP Shares and Woodside Shares (including New Woodside Shares) on capital account.

The summary below is not directed at Woodside Shareholders who are not Eligible BHP Shareholders. In addition the summary below does not apply to Woodside Shareholders who are also Eligible BHP Shareholders and who:

- hold their BHP Shares or their Woodside Shares (including New Woodside Shares) as revenue assets (which will generally be the case for applicable Woodside Shareholders who use their BHP Shares or their Woodside Shares in carrying on a business of share trading, banking or insurance) or as trading stock, or have acquired BHP Shares or Woodside Shares (including New Woodside Shares) for the purpose of on-sale at a profit;
- acquired their BHP Shares under any employee share scheme or where New Woodside Shares will be acquired pursuant to any employee share scheme;
- may be subject to special tax rules, including insurance companies, partnerships, tax exempt organisations, trusts (except where expressly stated), superannuation funds (except where expressly stated) or temporary residents; or

- are subject to the "taxation of financial arrangements" provisions in Division 230 of the Income Tax Assessment Act 1997 (Cth). It is noted that Division 230 will generally not apply to the financial arrangements of individuals, unless an election has been made for those rules to apply.

This taxation summary is based on the Australian tax law and administrative practice as it applies at the date of this Prospectus. The comments do not take into account or anticipate changes in Australian tax law, administrative practice or future judicial interpretations of Australian tax law after this time. Future amendments to taxation legislation, or its interpretation by the courts or the taxation authorities, may take effect retrospectively and/or affect the conclusions drawn.

This summary also does not take account of any individual circumstances of any Woodside Shareholder and does not constitute tax advice. It does not purport to be a complete analysis of the potential tax consequences of Implementation and the holding of New Woodside Shares and is intended as a general guide to the Australian tax implications. Woodside Shareholders who participate in the Merger should seek and rely upon specific advice applicable to their own circumstances from their own financial or tax advisers.

The summary in paragraph 2(a) of this Part 20 applies only to New Woodside Shares. The summary in paragraphs 2(b) – 2(e) of this Part 20 applies to New Woodside Shares and in most cases will also apply to existing Woodside Shares. Woodside Shareholders should seek and rely upon specific advice applicable to their own circumstances from their own financial or tax advisers in respect of the holding of Woodside Shares (including New Woodside Shares).

a) Implementation and receipt of New Woodside Shares

Overview of Transaction

BHP intends to distribute the New Woodside Shares to Eligible BHP Shareholders by way of an in-specie dividend (Special Dividend).

The Merger is not expected to qualify for demerger tax rollover relief in relation to the Special Dividend. BHP intends to fully frank the Special Dividend. Although the quantum of the Special Dividend will not be known until the date of distribution it will be based on the market value of New Woodside Shares at that time.

The following comments in this section set out the expected Australian income tax, GST and stamp duty consequences of receiving the Special Dividend for Woodside Shareholders who are also Eligible BHP Shareholders as a result of Implementation. The Australian income tax, GST and stamp duty consequences for those Woodside Shareholders of holding New Woodside Shares, including the receipt of dividends on those shares and the disposal of those shares, are set out below.

Class ruling application

BHP has applied to the Commissioner of Taxation (Commissioner) for a class ruling confirming certain income tax implications of Implementation for Australian resident Eligible BHP Shareholders. The final class ruling will be published by the Commissioner shortly after the Implementation.

The class ruling application is principally concerned with (i) confirming that demerger tax rollover relief will not be available to Eligible BHP Shareholders and (ii) confirming the Australian income tax consequences of the Special Dividend for Eligible BHP Shareholders.

The information below outlines the implications for Woodside Shareholders who are also Eligible BHP Shareholders in circumstances where demerger tax rollover relief does not apply and the Special Dividend is being distributed by way of a 100% dividend (subject to the Commissioner's approval).

Special Dividend

Australian resident shareholders

You should include the amount of the Special Dividend in your assessable income in the income year in which you receive the Special Dividend.

BHP intends to fully frank the Special Dividend and, accordingly, the Special Dividend will have accompanying franking credits.

Generally, provided you are a "qualified person" in relation to the Special Dividend and the Australian Taxation Office ("**ATO**") does not make a determination under the dividend streaming rules to deny the benefit of the franking credits attached to the Special Dividend, you should:

- also include the amount of the franking credits attached to the Special Dividend in your assessable income in the income year in which you receive the Special Dividend; and
- qualify for a tax offset equal to the amount of the franking credits attached to the Special Dividend, which can be applied against your income tax liability for the relevant income year.

You should be a "qualified person" in relation to the Special Dividend if the "holding period rule" and the "related payments rule" are satisfied. Generally:

- to satisfy the "holding period rule", you must have held your BHP Shares "at risk" for at least 45 days (not including the days of acquisition and disposal) within the period beginning on the day after the day on which you acquired them and ending 45 days after they become ex-distribution. This means that once you satisfy the "holding period rule" in relation to a distribution on your BHP Shares you do not need to satisfy it again in relation to those BHP Shares for subsequent distributions, unless you make a "related payment" (refer below); and
- under the "related payments rule", if you are obliged to make a "related payment" (essentially a payment passing on the benefit of the Special Dividend) in respect of the Special Dividend, you must hold your BHP Shares "at risk" for at least 45 days (not including the days of acquisition and disposal) within each period beginning 45 days before, and ending 45 days after, they become ex-distribution.

To be held "at risk", you must retain 30% or more of the risks and benefits associated with holding your BHP Shares. Where you undertake risk management strategies in relation to your BHP Shares (e.g. by the use of limited recourse loans, entering into put or call options in relation to your BHP Shares or other derivatives), your ability to satisfy the "at risk" requirement and thus to be a "qualified person" may be affected.

If you are an individual, you are automatically treated as a "qualified person" for these purposes if the total amount of the tax offsets in respect of all franked amounts to which you are entitled in an income year does not exceed A$5,000. This is referred to as the "small shareholder rule". However, you will not be a "qualified person" under the small shareholder rule if "related payments" have been made, or will be made, in respect of these amounts.

If you are an individual or complying superannuation fund you may be able to receive a cash tax refund from the ATO if the tax offset equal to the franking credits attached to the Special Dividend exceeds the tax payable on your total taxable income.

If you are a company the franking credits attached to the Special Dividend will generally give rise to a franking credit in your franking account. You will not be entitled to a tax refund of the excess franking credits. Rather, the surplus franking credits may be converted to a tax loss which can be carried forward to future years (subject to you satisfying certain loss carry forward rules).

Non-Australian resident shareholders

BHP intends to fully frank the Special Dividend. Accordingly, no part of the Special Dividend should be assessable to you in Australia nor subject to dividend withholding tax.

Cost base and date of acquisition of New Woodside Shares

The first element of the cost base and reduced cost base for each New Woodside Share you acquire on Implementation will be equal to the market value of the New Woodside Share at the time of the transfer of New Woodside Shares to you.

For CGT purposes (including the CGT discount) the date you acquire the New Woodside Shares should be the date of the distribution.

Further information will be provided by BHP to assist you in determining the amount of your Special Dividend and cost base for each New Woodside Share as soon as practical following Implementation.

Cost base of BHP Shares

On the basis that demerger tax roll-over relief does not apply, the Special Dividend will have no impact on the cost base and reduced cost base of your BHP Shares.

GST and stamp duty

No GST or Australian stamp duty should be payable by you in relation to the acquisition of New Woodside Shares as a result of Implementation.

b) Dividends on New Woodside Shares

This section applies to dividends that may be payable by Woodside as distinct from the Special Dividend to be received from BHP under which New Woodside Shares will be received by Eligible BHP Shareholders if the Merger is implemented.

Australian resident shareholders

If you receive a dividend on New Woodside Shares then the amount of the dividend will be included in your assessable income in the income year in which you receive the dividend.

Generally, provided you are a "qualified person" (as summarised above) in relation to a dividend received on the New Woodside Shares and the ATO does not make a determination under the dividend streaming rules to deny the benefit of the franking credits attached to any dividend you receive, you should:

- also include an amount equal to the franking credits attached to the dividend in your assessable income in the income year in which you receive the dividend; and
- qualify for a tax offset equal to the amount of the franking credits attached to the dividend which can be applied against your income tax liability for the relevant income year.

If you are an individual or complying superannuation fund you may be able to receive a cash tax refund from the ATO if the tax offset equal to the franking credits attached to the dividend exceeds the tax payable on your total taxable income.

If you are a company the franking credits attached to the dividend will generally give rise to a franking credit in your franking account. You will not be entitled to a tax refund of the excess franking credits. Rather, the surplus franking credits may be converted to a tax loss which can be carried forward to future years (subject to you satisfying certain loss carry forward rules).

Non-Australian resident shareholders

Dividends will not be subject to withholding tax to the extent the dividends are franked or relate to conduit foreign income.

To the extent an unfranked dividend is paid to you, withholding tax will be payable. The rate of withholding tax is 30%. However, you may be entitled to a reduction in the rate of withholding tax if you are resident in a country which has a double taxation agreement with Australia.

c) Disposal of New Woodside Shares

Australian resident shareholders

The disposal of a New Woodside Share will constitute a disposal for CGT purposes.

On disposal of a New Woodside Share, you will make a capital gain if the capital proceeds from the disposal exceed the cost base of the New Woodside Share. You will make a capital loss if the capital proceeds are less than the reduced cost base of the New Woodside Share.

The capital proceeds on disposal of a New Woodside Share will generally be the money you received, or that you are entitled to receive, in respect of the disposal plus the market value of any other property you received, or that you are entitled to receive, in respect of the disposal.

As set out in the section "*Implementation and receipt of New Woodside Shares – Special Dividend - Cost base and date of acquisition of Woodside Shares,*" the first element of the cost base and reduced cost base of each New Woodside Share you acquire on Implementation will be equal to the market value of the New Woodside Share at the time of the transfer of New Woodside Shares to you. Further information will be provided by BHP to assist you in determining the amount of your Special Dividend and cost base for each New Woodside Share as soon as practical following Implementation.

If you are an individual, trustee or complying superannuation entity that has held New Woodside Shares for 12 months or more at the time of disposal (not including the date of acquisition and disposal), you should be entitled to apply the applicable CGT discount factor to reduce the capital gain (after offsetting available capital losses). The CGT discount factor is 50% for individuals and trustees and 33 ⅓% for complying superannuation entities.

As set out above, you will be taken to have acquired New Woodside Shares for the purposes of the CGT discount on the date of the distribution. Accordingly, to be eligible for the CGT discount, you must have held New Woodside Shares for at least 12 months after the date of the distribution (not including the date of acquisition and disposal).

If you make a capital loss, you can only use that loss to offset other capital gains (i.e. the capital loss cannot be offset against taxable income on revenue account). However, if the capital loss cannot be used in a particular income year, you can carry it forward to use in future income years, providing certain loss utilisation tests are satisfied.

Non-Australian resident shareholders

If you are a non-resident of Australia for Australian income tax purposes and do not use your New Woodside Shares in carrying on a business through an Australian permanent establishment, the whole of any capital gain or capital loss made upon the disposal of your New Woodside Shares will be disregarded unless the New Woodside Shares constitute "indirect Australian real property interests". Your New Woodside Shares will constitute indirect Australian real property interests if:

- you hold a "non-portfolio interest" in Woodside. You will hold a "non-portfolio interest" in Woodside if you (together with your associates) hold 10% or more of the Woodside Shares:
  - at the time of disposal; or
  - throughout a 12-month period during the 24 months preceding the disposal; and
- your New Woodside Shares pass the "principal asset test".

If you are subject to tax on disposal of your New Woodside Shares, the CGT discount will generally not be available to reduce any capital gain that you make.

Non-Australian resident CGT withholding

Where a non-resident of Australia for Australian income tax purposes disposes of certain taxable Australian property, the purchaser is generally required to pay an amount to the ATO.

A purchaser of your New Woodside Shares will generally have an obligation to pay 12.5% of an amount equal to, broadly, the capital proceeds for the disposal of your New Woodside Shares (discussed in the section "*Disposal of Woodside Shares - Australian resident shareholders"*) ("**CGT Withholding Tax**") to the ATO if your New Woodside Shares are "indirect Australian real property interests" (discussed above) and the purchaser:

- knows or reasonably believes that you are a non-resident of Australia; or
- does not reasonably believe that you are an Australian resident, and either:
  - you have an address outside Australia; or
  - the purchaser is authorised to pay the purchase price to a place outside Australia.

However, a purchaser may not be required to pay CGT Withholding Tax if you can make a declaration that:

- as the registered holder of New Woodside Shares, you are an Australian tax resident; or
- your New Woodside Shares are not indirect Australian real property interests.

If a purchaser considers that an obligation to pay CGT Withholding Tax arises, the purchaser is generally permitted to withhold an amount equal to the CGT Withholding Tax from any amount payable to you on disposal. In that instance, you will only receive the net proceeds from the disposal but will be taken to receive the full proceeds. Any CGT Withholding Tax withheld is not a final tax. You will receive a credit for amounts withheld on filing an Australian tax return and you may receive a refund of tax if amounts have been withheld in excess of your actual Australian tax liability.

d) Provision of TFN and/or ABN

Woodside may be required to withhold tax (currently at the rate of 47%) on payments made to you (including payments of dividends that are not fully franked) and remit the amounts withheld to the ATO, unless you have provided a TFN, ABN or you have informed Woodside that you are exempt from quoting your TFN or ABN (including because you are a non-Australian resident).

You are not required to provide your TFN or ABN to Woodside, however you may choose to do so.

e) Other Australian taxes

No GST or stamp duty should be payable by you in relation to the receipt of dividends on New Woodside Shares held by you or in respect of the disposal of New Woodside Shares.

3. US Taxation

a) Holding of the shares

Material U.S. federal income tax considerations

The following describes the material U.S. federal income tax considerations for beneficial owners of BHP Shares or BHP ADSs (together, "**BHP Securities**") that are U.S. Holders of the receipt of Woodside ADSs or Woodside ordinary shares (together, "**Woodside Securities**") pursuant to the Special Dividend and the subsequent ownership and disposition of such Woodside Securities. This discussion applies only to Woodside Securities held as a "capital asset" for U.S. federal income tax purposes (generally property held for investment). This summary is based on the provisions of the Internal Revenue Code of 1986, as amended (the "**Code**"), U.S. Treasury regulations, any tax treaties, administrative rulings, and judicial decisions, all as in effect on the date hereof, and all of which are subject to change and differing interpretations, possibly with retroactive effect. Woodside cannot assure you that any such change or differing interpretation will not significantly alter the tax considerations described in this discussion. Neither Woodside nor BHP has sought or will seek any rulings from the Internal Revenue Service (the "**IRS**") with respect to the statements, positions or conclusions described in the following discussion. Such statements, positions and conclusions are not free from doubt, and there can be no assurance that your or Woodside's tax advisers, the IRS, or a court will agree with such statements, positions, and conclusions. In addition, statements contained herein that BHP or Woodside "believes," "expects," "intends," "anticipates," or other similar phrases are not legal conclusions or opinions of Vinson & Elkins L.L.P.

The following does not purport to be a complete analysis of all potential tax effects resulting from the ownership or disposition of Woodside Securities after the Merger and does not address all aspects of U.S. federal income taxation that may be relevant to individual U.S. Holders in light of their particular circumstances. In addition, this summary does not address the Medicare tax on certain investment income, U.S. federal estate or gift tax laws, any state, local, or non-U.S. tax laws, any tax treaties, or any other tax laws. Furthermore, this summary does not address all U.S. federal income tax considerations that may be relevant to certain categories of U.S. Holders that may be subject to special treatment under the U.S. federal income tax laws, including, but not limited to:

- banks, insurance companies, or other financial institutions;
- tax-exempt or governmental organisations;
- dealers in securities or foreign currencies;
- persons whose functional currency is not the U.S. dollar;
- persons that actually or constructively own 5% or more of any class of Woodside's stock (by vote or by value);
- corporations that accumulate earnings to avoid U.S. federal income tax;
- traders in securities that use the mark-to-market method of accounting for U.S. federal income tax purposes;

- persons subject to the alternative minimum tax;
- entities or arrangements treated as partnerships or other pass-through entities for U.S. federal income tax purposes or holders of interests therein;
- persons deemed to sell Woodside Securities under the constructive sale provisions of the Code;
- real estate investment trusts;
- regulated investment companies;
- persons that hold Woodside Securities as part of a straddle, appreciated financial position, synthetic security, hedge, conversion transaction, or other integrated investment or risk reduction transaction; or
- U.S. Holders of Woodside Securities prior to the Merger.

THIS DISCUSSION IS NOT TAX ADVICE. U.S. HOLDERS SHOULD CONSULT WITH, AND RELY SOLELY UPON, THEIR TAX ADVISERS WITH RESPECT TO THE APPLICATION OF U.S. FEDERAL INCOME TAX LAWS (INCLUDING ANY POTENTIAL CHANGES THERETO) TO THEIR PARTICULAR SITUATIONS, AS WELL AS ANY TAX CONSEQUENCES ARISING UNDER ANY OTHER TAX LAWS, INCLUDING, BUT NOT LIMITED TO, U.S. FEDERAL ESTATE OR GIFT TAX LAWS, THE LAWS OF ANY STATE, LOCAL OR NON-U.S. TAXING JURISDICTION, OR ANY APPLICABLE INCOME TAX TREATY.

b) U.S. Holder Defined

For the purposes of this discussion, the term "U.S. Holder" is used to mean, with respect to BHP or Woodside, respectively a beneficial owner of BHP Securities or Woodside Securities that, for U.S. federal income tax purposes, is:

- an individual who is a citizen or resident of the United States;
- a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organised in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust (A) the administration of which is subject to the primary supervision of a U.S. court and which has one or more "United States persons" (within the meaning of Section 7701(a)(30) of the Code) who have the authority to control all substantial decisions of the trust or (B) that has made a valid election under applicable U.S. Treasury regulations to be treated as a United States person.

If a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds BHP Securities or Woodside Securities, the tax treatment of a partner in such partnership might depend upon the status of the partner or the partnership, upon the activities of the partnership and upon certain determinations made at the partnership or partner level. Accordingly, Woodside urges partners in partnerships (including entities or arrangements treated as partnerships for U.S. federal income tax purposes) holding BHP Securities or Woodside Securities to consult with, and rely solely upon, their own tax advisers regarding the U.S. federal income and other tax considerations to them of the matters discussed below.

c) American Depositary Shares

For U.S. federal income tax purposes, U.S. Holders of BHP ADSs or Woodside ADSs generally should be treated as the beneficial owners of the underlying shares represented by the ADSs and an exchange of ADSs for such underlying shares generally will not be subject to U.S. federal income tax. Throughout the remainder of this discussion, any reference to a holder of Woodside Shares or BHP Shares, respectively, is assumed to includes holders of Woodside ADSs or BHP ADSs.

The U.S. Treasury has expressed concerns that parties to whom American depositary shares are released before delivery of shares to the depositary, or intermediaries in the chain of ownership between U.S. Holders and the issuer of the security underlying the American depositary shares, may be taking actions that are inconsistent with U.S. Holders of the American depositary shares claiming foreign tax credits. These actions could also be inconsistent with the claiming of the reduced rate of tax, described below, applicable to dividends received by certain non-corporate U.S. Holders. Accordingly, the availability of foreign tax credits or the reduced U.S. federal income tax rate for "qualified dividend income," each discussed below, could be affected by actions taken by intermediaries in the chain of ownership between the holder of a Woodside ADS or BHP ADS and Woodside or BHP, respectively, if as a result of such actions the U.S. Holder of a Woodside ADS or BHP ADS is not properly treated as the beneficial owner of the underlying share. Woodside cannot make any assurances to U.S. Holders regarding the actions of such persons or the tax impact of such actions.

d) Material U.S. Federal Income Tax Considerations for U.S. Holders of BHP Securities with Respect to the Receipt of New Woodside Shares Pursuant to the Special Dividend

U.S. Federal Income Tax Consequences of the Special Dividend.

Subject to the discussion of passive foreign investment company ("**PFIC**") taxation below, a U.S. Holder of BHP Securities must include in its gross income the gross amount of any dividend paid by BHP to the extent of its current or accumulated earnings and profits (as determined for U.S. federal income tax purposes). Distributions in excess of current and accumulated earnings and profits, as determined for U.S. federal income tax purposes, are treated as a non-taxable return of capital to the extent of the U.S. Holder's basis in BHP Securities, causing a reduction in the U.S. Holder's adjusted basis in BHP Securities, and thereafter as capital gain. However, BHP does not calculate earnings and profits in accordance with U.S. federal income tax principles. Accordingly, U.S. Holders should expect to treat the entire amount of the Special Dividend as a taxable dividend for U.S. federal income tax purposes.

The amount of the dividend distribution that U.S. Holders must include in their income will be the fair market value (expressed in U.S. dollars) of the New Woodside Securities as of the date of the distribution of the Special Dividend. A U.S. Holder must also include any foreign tax withheld from the dividend payment in the gross amount of the dividend even though the shareholder does not in fact receive the amount withheld. The dividend is taxable to a U.S. Holder when the U.S. Holder receives the dividend, actually or constructively.

Dividends paid to a non-corporate U.S. Holder by certain "qualified foreign corporations" that constitute qualified dividend income are taxable to the shareholder at the preferential rates applicable to long-term capital gains provided that the shareholder holds the BHP Securities for more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. For this purpose, BHP Securities will be treated as stock of a qualified foreign corporation if BHP is eligible for the benefits of an applicable comprehensive income tax treaty with the United States or if such BHP Securities are readily tradeable on an established securities market in the United States. The BHP ADSs are listed on the NYSE, and it is expected that it will be eligible for the benefits of such a treaty. Accordingly, subject to the discussion of PFIC taxation below, it is expected that the dividends it pays with respect to the Special Dividend will constitute qualified dividend income to a non-corporate U.S. Holder, assuming the U.S. Holder's holding period requirements are met. Dividends paid to a corporate U.S. Holder will not be eligible for the dividends-received deduction.

The Australian withholding tax consequences of the Special Dividend paid to non-Australian resident Eligible BHP Shareholders are outlined in the section titled Part 22 *(Definitions and Glossary)*. If Australian dividend withholding tax is payable on the Special Dividend, U.S. Holders should seek their own tax advice to determine the Australian and U.S. taxation implications. Subject to certain limitations, any non-U.S. tax withheld and paid over to a non-U.S. taxing authority (including Australian withholding tax) is eligible for credit against a U.S. Holder's U.S. federal income tax liability except to the extent a refund of the tax withheld is available to the U.S. Holder under non-U.S. tax law or under an applicable tax treaty. Special rules apply in determining the foreign tax credit limitation with respect to dividends that are taxed at the preferential rates applicable to long-term capital gains. The amount allowed to a U.S. Holder as a credit is limited to the amount of the U.S. Holder's U.S. federal income tax liability that is attributable to income from sources outside the U.S. and is computed separately with respect to different types of income that the U.S. Holder receives from non-U.S. sources. To the extent a reduction or refund of the tax withheld is available to a U.S. Holder under non-U.S. law or under an income tax treaty, the amount of tax withheld that could have been reduced or that is refundable will not be eligible for credit against the holder's U.S. federal income tax liability. A U.S. Holder that does not elect to claim a U.S. foreign tax credit may instead claim a deduction for non-U.S. income tax withheld, but only for a taxable year in which the U.S. Holder elects to do so with respect to all non-U.S. income taxes paid or accrued in such taxable year. Dividends will be income from sources outside the U.S. and generally will be "passive category" income for the purpose of computing the foreign tax credit allowable to a U.S. Holder. In general, a taxpayer's ability to use foreign tax credits may be limited and is dependent on the particular circumstances. U.S. Holders should consult their tax advisers with respect to these matters.

BHP PFIC Considerations.

BHP believes that the BHP Securities will not be stock of a PFIC for U.S. federal income tax purposes, but this conclusion is based on a factual determination made annually and thus is subject to change. With certain exceptions, a U.S. Holder's BHP Securities would be treated as stock in a PFIC if BHP were a PFIC at any time during such U.S. Holder's holding period of the BHP Securities.

If BHP Securities were treated as stock of a PFIC with respect to a US Holder, the U.S. Holder would be liable to pay U.S. federal income tax at the highest applicable income tax rates on any dividend income attributable to the Special Dividend and, potentially, interest on all or a portion of such amount as if such dividend had been recognised rateably over the U.S. Holder's holding period of the BHP Securities.

Any dividend income resulting from the Special Dividend would not be eligible for the preferential tax rates applicable to qualified dividend income if BHP were treated as a PFIC in the taxable years in which the dividends are paid or in the preceding taxable year (regardless of whether the U.S. Holder held BHP Securities in such year) but instead would be taxable at rates applicable to ordinary income.

Subject to certain exceptions, BHP would be treated as a PFIC in any taxable year in which, after applying certain look-through rules, either:

i. at least 75% of its gross income for such taxable year, including its pro rata share of the gross income of any corporation in which it is considered to own at least 25% of the shares by value, consists of passive income (which generally includes dividends, interest, rents and royalties (other than rents or royalties derived from the active conduct of a trade or business) and gains from the disposition of passive assets); or

ii. at least 50% of its assets in such taxable year (ordinarily determined based on fair market value and averaged quarterly over the year), including its pro rata share of the assets of any corporation in which BHP is considered to own at least 25% of the shares by value, produce or are held for the production of passive income.

Because the determination of whether a foreign corporation is a PFIC is primarily factual and there is little administrative or judicial authority on which to rely to make such a determination, the IRS might not agree that BHP is not a PFIC.

If BHP were later determined to be a PFIC, you may be unable to make certain advantageous elections with respect to your ownership of BHP Securities (including a "mark-to-market" election or a "qualified electing fund" election) that would mitigate the adverse consequences of BHP's PFIC status, or making such elections retroactively could have adverse tax consequences to you. The remainder of this discussion assumes that BHP will not be treated as a PFIC in the taxable year of the Merger or any prior taxable year. **THE PFIC RULES ARE COMPLEX AND UNCERTAIN. U.S. HOLDERS SHOULD CONSULT WITH, AND RELY SOLELY UPON, THEIR TAX ADVISERS TO DETERMINE THE APPLICATION OF THE PFIC RULES TO THEM AND ANY RESULTANT TAX CONSEQUENCES.**

Cost base of BHP Securities and Woodside Securities.

Given the assumption that the Special Dividend will be treated as a dividend for U.S. federal income tax purposes, it is not expected that the receipt of the Special Dividend should impact a U.S. Holder's basis in its BHP Securities. A U.S. Holder will have an initial tax basis in the Woodside Securities it receives pursuant to the Special Dividend equal to the fair market value (expressed in U.S. dollars) of the New Woodside Securities as of the date of the distribution of the Special Dividend.

e) Material U.S. Federal Income Tax Considerations for U.S. Holders with Respect to the Ownership and Disposition of Woodside Securities

Woodside PFIC Considerations.

Adverse and burdensome U.S. federal income tax rules and consequences apply to U.S. Holders that hold stock in a non-U.S. corporation classified as a PFIC for U.S. federal income tax purposes. In general, Woodside would be treated as a PFIC in any taxable year in which, after applying certain look-through rules, either:

i. at least 75% of its gross income for such taxable year, including its pro rata share of the gross income of any corporation in which it is considered to own at least 25% of the shares by value, consists of passive income (which generally includes dividends, interest, rents and royalties (other than rents or royalties derived from the active conduct of a trade or business) and gains from the disposition of passive assets); or

ii. at least 50% of its assets in such taxable year (ordinarily determined based on fair market value and averaged quarterly over the year), including its pro rata share of the assets of any corporation in which Woodside is considered to own at least 25% of the shares by value, produce or are held for the production of passive income.

While Woodside does not anticipate becoming a PFIC in the current or future taxable years, there can be no assurance that it will not be a PFIC for any taxable year, as PFIC status is tested each taxable year and depends on the composition of its assets and income in such taxable year. If Woodside is classified as a PFIC for any year during which a U.S. Holder holds Woodside Securities, Woodside will generally continue to be treated as a PFIC for all succeeding years during which such U.S. Holder holds Woodside Securities. Because PFIC status is a fact-intensive determination made on an annual basis and depends on the composition of Woodside's assets and income at such time, no assurance can be given that Woodside is not or will not become classified as a PFIC. If Woodside were later determined to be a PFIC, you may be unable to make certain advantageous elections with respect to your ownership of Woodside Securities (including a "mark-to-market" election or a "qualified electing fund" election) that would mitigate the adverse consequences of Woodside's PFIC status or making such elections retroactively could have adverse tax consequences to you. Woodside has not sought and will not seek any rulings from the IRS or any opinion from any tax adviser as to such tax treatment, and the closing of the Merger is not conditioned upon achieving or receiving a ruling from any tax authority or opinion from any tax advisers in regards to, any particular tax treatment. Thus, the anticipated reporting position of Woodside described herein is not free from doubt. Woodside is not representing to you that Woodside will not be treated as a PFIC for the taxable year of the Merger or in any future taxable years.

Consistent with Woodside's expectation, the remainder of this discussion assumes that Woodside will not be treated as a PFIC in the taxable year of the Merger or any subsequent taxable year.

THE PFIC RULES ARE COMPLEX AND UNCERTAIN. U.S. HOLDERS SHOULD CONSULT WITH, AND RELY SOLELY UPON, THEIR TAX ADVISERS TO DETERMINE THE APPLICATION OF THE PFIC RULES TO THEM AND ANY RESULTANT TAX CONSEQUENCES.

Tax Characterisation of Distributions with Respect to Woodside Securities.

If Woodside pays a distribution in cash or other property to U.S. Holders of Woodside Securities, such distribution generally will constitute a dividend for U.S. federal income tax purposes to the extent paid from current or accumulated earnings and profits as determined under U.S. federal income tax principles. Distributions in excess of current and accumulated earnings and profits will constitute a return of capital that will be applied against and reduce (but not below zero) the U.S. Holder's adjusted tax basis in its Woodside Securities. Any remaining excess will be treated as gain realised on the sale of Woodside Securities and will be treated as in the section entitled "*Gain or Loss on Sale or Other Taxable Exchange or Disposition of Woodside Securities*." However, because Woodside does not expect to determine its earnings and profits on the basis of United States federal income tax principles, U.S. holders should expect that any distribution paid will generally be reported to them as a "dividend" for U.S. federal income tax purposes.

The amount of any distribution paid in a foreign currency will be equal to the U.S. dollar value of such currency, translated at the spot rate of exchange on the date such distribution is received, regardless of whether the payment is in fact converted into U.S. dollars at that time. If the distribution is converted into U.S. dollars on the date of receipt, a U.S. Holder should not be required to recognise foreign currency gain or loss in respect of the income attributable to such distribution. A U.S. Holder may have foreign currency gain or loss if the distribution is converted into U.S. dollars after the date of receipt. In general, foreign currency gain or loss will be treated as U.S.-source ordinary income or loss.

Distributions Treated as Dividends.

Dividends paid by Woodside will be taxable to a corporate U.S. Holder at regular rates and will not be eligible for the dividends-received deduction generally allowed to U.S. corporations in respect of dividends received from other U.S. corporations. Dividends Woodside pays to a non-corporate U.S. Holder generally will constitute a "qualified dividend" that will be subject to U.S. federal income tax at the maximum tax rate accorded to long-term capital gains if Woodside Securities are readily tradable on an established securities market in the United

States or if Woodside is eligible for certain benefits under the tax treaty between the United States and Australia and certain holding period and other requirements are met, including that Woodside is not classified as a PFIC during the taxable year in which the dividend is paid or a preceding taxable year. If such requirements are not satisfied, a non-corporate U.S. Holder may be subject to tax on the dividend at regular ordinary income tax rates instead of the preferential rate that applies to qualified dividend income. U.S. Holders should consult with, and rely solely upon, their tax advisers regarding the availability of the lower preferential rate for qualified dividend income for any dividends paid with respect to Woodside Securities.

Woodside believes that it currently is, and anticipates continuing to be, eligible for benefits under the tax treaty between the United States and Australia. Under a published IRS Notice, common or ordinary shares, or ADSs representing such shares, are considered to be readily tradable on an established securities market in the United States if they are listed on the NYSE, as the Woodside ADSs are expected to be so listed. However, based on existing guidance, it is unclear whether the shares underlying the Woodside ADSs will be considered to be readily tradable on an established securities market in the United States, because only the Woodside ADSs will be listed on a securities market in the United States. U.S. Holders are urged to consult with, and rely solely upon, their own tax advisers regarding the availability of the favourable rate applicable to qualified dividend income for any dividends Woodside pays with respect to the Woodside ADSs.

Dividends paid with respect to Woodside Securities generally will constitute foreign source income for U.S. foreign tax credit limitation purposes. Subject to certain complex conditions and limitations, any Australian taxes withheld on any distributions on Woodside Securities may be eligible for credit against a U.S. Holder's federal income tax liability or, at such holder's election, may be eligible as a deduction in computing such holder's U.S. federal taxable income. If a refund of the tax withheld is available under the laws of Australia or under the tax treaty between the United States and Australia, as amended, the amount of tax withheld that is refundable will not be eligible for such credit against a U.S. Holder's U.S. federal income tax liability (and will not qualify for the deduction against U.S. federal taxable income). If the dividends constitute qualified dividend income as discussed above, the amount of the dividend taken into account for purposes of calculating the foreign tax credit limitation will generally be limited to the gross amount of the dividend, multiplied by the reduced rate applicable to the qualified dividend income, divided by the highest rate of tax normally applicable to dividends. The limitation on foreign taxes eligible for the credit is calculated separately concerning specific classes of income. For this purpose, dividends distributed by the Woodside with respect to Woodside Securities will generally constitute "passive category income". The rules relating to the determination of the U.S. foreign tax credit are complex, and U.S. Holders are urged to consult with, and rely solely upon, their tax advisers regarding the availability of a foreign tax credit in their particular circumstances and the possibility of claiming an itemised deduction (in lieu of the foreign tax credit) for any foreign taxes paid or withheld.

Withholding tax in Australia.

The Australian withholding tax consequences of dividends paid to non-Australian resident shareholders are outlined in paragraph 2 of this Part 20. If Australian dividend withholding tax is payable on dividends from Woodside, U.S. Holders should seek their own tax advice to determine the Australian and U.S. taxation implications.

Gain or Loss on Sale or Other Taxable Exchange or Disposition of Woodside Securities.

Upon a sale or other taxable exchange or disposition of Woodside Securities (including any portion of a distribution by Woodside treated as such per the section titled "*—Tax Characterisation of Distributions with Respect to Woodside Securities")*, a U.S. Holder generally will recognise capital gain or loss in an amount equal to the difference between (i) the sum of the amount of cash and the fair market value of any property received in such exchange or disposition and (ii) the U.S. Holder's adjusted tax basis in its Woodside Securities so disposed of. A U.S. Holder's adjusted tax basis in its Woodside Securities generally will equal the fair market value (expressed in U.S. dollars) of the New Woodside Securities as of the date of the distribution of the Special Dividend, less, in the case of a Woodside Security, any prior distributions paid to such U.S. Holder that were treated as a return of capital for U.S. federal income tax purposes. Any such capital gain or loss generally will be long-term capital gain or loss if the U.S. Holder held the Woodside Securities for more than one year. Long-term capital gains recognised by non-corporate U.S. Holders will be eligible to be taxed at reduced rates. In addition, the deductibility of capital losses is subject to limitations.

Gain or loss, if any, realised by a U.S. Holder on the sale or other disposition of Woodside Securities generally will be treated as U.S. source gain or loss for U.S. foreign tax credit limitation purposes. The use of U.S. foreign tax credits relating to any Australian tax imposed upon the sale or other disposition of Woodside Securities may be unavailable or limited and may depend upon the application of the tax treaty between the United States and Australia to such U.S. Holder. U.S. Holders are urged to consult with, and rely solely upon, their own tax advisers regarding the tax consequences if Australian taxes are imposed on or connected with a sale or other disposition of Woodside Securities and their ability to credit any Australian tax against their U.S. federal income tax liability.

Australian CGT consequences.

Australian CGT consequences of disposals of Woodside Shares by U.S. holders are outlined at paragraph 2 of this Part 20. If any tax is payable in Australia on a gain accruing on the disposal of Woodside Shares, U.S. Holders should seek their own tax advice to determine the Australian and U.S. taxation implications.

Information Reporting and Backup Withholding.

The Special Dividend, dividends with respect to Woodside Securities and proceeds from the sale or exchange of Woodside Securities may be subject, under certain circumstances, to information reporting and backup withholding. Backup withholding will not apply, however, to a U.S. Holder that (i) is a corporation or entity that is otherwise exempt from backup withholding (which, when required, certifies as to its exempt status) or (ii) furnishes a correct taxpayer identification number and makes any other required certification on IRS Form W-9. Backup withholding is not an additional tax. Rather, the U.S. federal income tax liability (if any) of persons subject to backup withholding will be reduced by the amount of tax withheld. If backup withholding results in an overpayment of taxes, a refund generally may be obtained, provided that the required information is timely furnished to the IRS.

Additional Information Reporting Requirements.

Certain U.S. Holders may be required to comply with certain reporting requirements relating to the Woodside Securities with respect to the holding of certain foreign financial assets, including stock of foreign issuers (such as Woodside). Penalties can apply if U.S. Holders fail to satisfy such reporting requirements. U.S. Holders are urged to consult with, and rely solely upon, their own tax advisers regarding the application of these rules to their ownership of the Woodside Securities.

THE FOREGOING DISCUSSION IS NOT TAX ADVICE OR A COMPREHENSIVE DISCUSSION OF ALL U.S. FEDERAL INCOME TAX CONSEQUENCES TO U.S. HOLDERS OF WOODSIDE SECURITIES. SUCH HOLDERS SHOULD CONSULT WITH, AND RELY SOLELY UPON, THEIR OWN TAX ADVISERS TO DETERMINE THE SPECIFIC TAX CONSEQUENCES TO THEM OF THE MERGER AND OF OWNING WOODSIDE SECURITIES FOLLOWING THE COMPLETION OF THE MERGER, INCLUDING THE EFFECT OF ANY U.S. FEDERAL, STATE, LOCAL, NON-U.S., OR OTHER TAX LAWS.

Part 21 – Additional Information

1 Responsibility statement

Woodside

Woodside and each of the Directors, whose names appear in Part 25 *(Directors, Secretary, Registered Office and Advisers)* of this Prospectus, accept responsibility for the information contained in this Prospectus. To the best of the knowledge of Woodside and the Directors, the information contained in this Prospectus is in accordance with the facts and this Prospectus makes no omission likely to affect its import.

BHP

BHP accepts responsibility for the BHP Information. To the best of the knowledge of BHP, the BHP Information is in accordance with the facts and the BHP Information makes no omission likely to affect its import.

2 Competent Person's responsibility statement

The Competent Person accepts responsibility for the CPR contained in Annexure 3 of Part 24 *(Competent Person's Report)* of this Prospectus. To the best of the knowledge of the Competent Person, the information contained in the CPR including the estimates of reserves section contained therein, as well as references to them, and statements and information attributed to the Competent Person or extracted from the CPR and included in this Prospectus, is in accordance with the facts and contains no omissions likely to affect the import of such information.

3 The Company

On 17 August 1971, Woodside Petroleum Ltd (to be renamed Woodside Energy Group Ltd prior to Admission[56]) was incorporated, under the Corporations Act with company number 004 898 962. Woodside is domiciled in Australia and is registered in Victoria as a public company and its LEI number is 2549005ZC5RXAOO7FH41. Woodside listed on the ASX on 18 November 1971. Woodside's registered office is Mia Yellagonga, 11 Mount Street, Perth WA 6000 Australia, and the head office and principal place of business of Woodside is at the same location. Woodside's telephone number is +61 8 9348 4000. Woodside's website is accessible at https://www.woodside.com.au/. Information contained on Woodside's website or the contents of any website accessible from hyperlinks on Woodside's website are not incorporated into and do not form any part of this Prospectus.

The principal legislation under which Woodside operates with conformity is the Corporations Act. Woodside operates in conformity with the Woodside Constitution and is duly authorised by the Woodside Constitution in respect of the Admission.

Woodside has all necessary statutory consents in connection with its Admission.

4 Share Capital of Woodside

As at the Last Practicable Date, Woodside had an issued share capital of 983,980,823. The issued share capital of Woodside immediately after Admission is expected to be 1,898,749,771 Woodside Shares[57]. The liability of each Woodside Shareholder is limited to the amount, if any, unpaid on the shares held by that shareholder. The Woodside Shares are fully paid and freely transferable. The Woodside Share have no par value.

The Woodside Shares will be registered and are held in uncertificated form (by way of Depositary Interests) on the LSE.

On Admission, it is expected that approximately 89% of the Woodside Shares will be held in public hands (within the meaning of LSE Listing Rule 14.2.2(4)).

As at 31 December 2021, the total securities of Woodside in issue were as follows:

(i) 969,631,826 issued and fully paid Woodside Shares;

(ii) 5,649,783 equity rights;

(iii) 1,109,471 performance rights;

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56 Subject to approval by the Woodside Shareholders at the Woodside Shareholders' Meeting.

57 Based on number of Woodside Shares in issue as at the Last Practicable Date and assumes no additional Woodside Shares are issued between the Last Practicable Date and Implementation.

(iv) 647,765 variable pay rights; and

(v) 1,819,744 Woodside Shares reserved for employee share plans.

Contributed Equity (as at 31 December 2021)	Number of Woodside Shares	Total Value on Balance Sheet US$m
Issued and fully paid Woodside Shares	969,631,826	9,409
Woodside Shares reserved for employee share plans (includes Restricted Shares and unallocated shares held in Woodside's employee share plan trust)	1,819,744	(30)

Ordinary shares are classified as equity and recorded at the value of consideration received. The cost of issuing shares is shown in share capital as a deduction, net of tax, from the proceeds.

During the period covered by the Historical Financial Information, there have been the following changes to Woodside's issued share capital:

	Shares Issued
Balance at 31 December 2017	842,444,903
Issued at A$27.00 per ordinary share under a fully underwritten pro rata accelerated renounceable entitlement offer	93,706,646
Balance at 31 December 2018	936,151,549
Issued at A$31.34 per ordinary share under the Woodside Dividend Reinvestment Plan	6,135,351
Balance at 31 December 2019	942,286,900
Issued at A$25.61 per ordinary share under the Woodside Dividend Reinvestment Plan	12,072,034
Issued at A$18.79 per ordinary share under the Woodside Dividend Reinvestment Plan	6,091,035
Issued at A$18.27 per ordinary share under Woodside's employee incentive schemes	1,775,845
Balance at 31 December 2020	962,225,814
Issued at A$24.77 per ordinary share under the Woodside Dividend Reinvestment Plan	1,354,072
Issued at A$19.47 per ordinary share under the Woodside Dividend Reinvestment Plan	6,051,940
Balance as at the end of the year 2021	969,631,826

In the period following the year covered by the Historical Financial Information, there have been the following changes to the Company's issue share capital

Movement in share capital	31 December 2021 to the Last Practicable Date
Balance at 31 December 2021	969,631,826
Issued at A$31.27 per ordinary share under the Woodside Dividend Reinvestment Plan	14,348,997
Total issued share capital as at the Last Practicable Date	**983,980,823**

5 Australian takeover provisions

Woodside is incorporated in and has its head office and central place of management in Australia. Accordingly, the following Australian legislation and regulations in relation to takeovers apply to Woodside:

- the Corporations Act, particularly Chapter 6 (the relevant provisions of which are outlined below);
- the Foreign Acquisitions and Takeovers Act 1975 (Cth) ("**FATA**"); and
- the Competition and Consumer Act 2010 (Cth).

The main Australian regulatory bodies are:

- ASIC which is responsible for administering and enforcing the Corporations Act;
- the Australian Takeovers Panel, which is the principal forum for resolving disputes relating to a takeover during the bid period; and
- the ASX.

If a proposed investor is a foreign company for the purposes of FATA, the acquisition may need to be approved by the Treasurer of Australia acting on the advice of the FIRB.

If competition issues are likely to arise, the Australian Competition and Consumer Commission ("**ACCC**") may become involved. The ACCC administers the Competition and Consumer Act 2010 (Cth).

Chapter 6 of the Corporations Act

Takeover prohibition

Section 606 of the Corporations Act prohibits a person from acquiring a "relevant interest" in voting shares in a listed company or an unlisted company with more than 50 shareholders if, because of the acquisition, that person's or someone else's voting power increases:

- from 20% or below to more than 20%; or
- from a starting point that is above 20% and below 90%.

A person generally has a "relevant interest" in a share if they hold the share, have the power to exercise or control the exercise of the voting power attached to the share, or have the power to dispose of or control the disposal of the share. The term "voting power" is defined in broad terms and captures any relevant interest in shares held by a person's "associates".

These concepts are broad and, for example, a person can have a relevant interest and voting power in a share as a result of an agreement to purchase the share (even a conditional agreement) or a call option to acquire the share.

The concept of "associates" is complex, and generally includes:

(1) a person with whom the primary person is acting, or proposing to act, in concert in relation to the company's affairs;

(2) persons with whom the primary person has entered or proposed to enter into an agreement for the purpose of controlling or influencing the composition of the company's board or the conduct of the company's affairs; and

(3) companies that the primary person controls, that control the primary person, or that are controlled by an entity that controls the primary person.

Exceptions to the Australian takeovers prohibition

If a person wishes to acquire more than 20% of a company or increase a holding which is already above 20% (but less than 90%), the person must do so under an exception. There are four principal exceptions to the general prohibition under section 606 of the Corporations Act which are relevant in this context:

(1) Takeover bids;

(2) Schemes of arrangement;

(3) "Creeping" acquisitions; and

(4) Shareholder approved acquisitions.

Proportional takeover provisions

In addition to these takeover offer requirements, the Corporations Act provides that a listed entity may include provisions in its constitution which effectively require disinterested shareholder approval of any proposed takeover bid that is for less than all of the voting securities issued by the entity (other than those held by the bidder). In effect, this mean that a transfer of shares in relation to a proportional takeover bid must not be registered unless shareholders pass a resolution to approve the bid. The Woodside Constitution includes provisions of this type. It provides that where an offer has been made under a proportional takeover bid (meaning an off-market bid for a specified proportion of the securities in the bid class) in respect of shares included in a class of shares in Woodside, registration of a transfer to effect a contract resulting from the acceptance of an offer made under the proportional takeover bid is prohibited unless and until a resolution to approve the proportional takeover bid is passed in accordance with the Woodside Constitution. The Woodside Board must convene a meeting of the persons entitled to vote on a resolution to approve the proportional takeover bid for the purposes of considering and, if thought fit, passing the resolution. Any shareholder that (i) is not the bidder or an associate of the bidder and (ii) at the end of the day on which the first offer under the proportional takeover bid was made, held shares included in that class, is entitled to vote on the resolution. A resolution to approve the proportional takeover bid is taken to have been passed if a majority of votes validly cast in favour of the resolution is greater than 50%. The Woodside Board must ensure that the meeting to consider the resolution to approve the proportional takeover bid is convened, and voted on in accordance with the Woodside Constitution, before the approving resolution deadline in relation to the proportional takeover bid. The approving resolution deadline is the 14th day before the last day of the bid period and during which the offers under the proportional takeover bid remain open or a later day allowed by ASIC. The proportional takeover provisions do not apply to full takeover bids and must be refreshed every 3 years by a special resolution of shareholders. The proportional takeover bid provisions in Woodside's Constitution were adopted on 2 May 2019, and the Company is seeking renewal of the proportional takeover bid provisions at the Woodside Shareholders' Meeting.

Foreign investment

FATA

Foreign investment in, and ownership of, Australian businesses, entities and land is regulated under the FATA. The FATA is administered by the Foreign Investment Review Board Secretariat a division of the Treasury Department of the Australian Government. The ultimate responsibility for making decisions on foreign investment proposals rests with the Treasurer of the Australian Government.

Investment proposals by foreign persons may need to be notified to the Australian Government and may require prior approval from the Treasurer in accordance with the FATA. In general, private sector foreign persons investors must notify the Australian Government and get prior approval before acquiring a substantial interest in an Australian entity that is valued above certain monetary thresholds. Notification may also be required in relation to acquisitions of interests in a foreign entity that is a national security business under the FATA or is an Australian land-rich entity, or in respect of a foreign government investor, the acquisition of an interest in a foreign entity that holds a substantial interest in Australian subsidiaries valued above the applicable monetary thresholds.

The FATA and regulations under the FATA provide the relevant monetary thresholds that apply. From 1 January 2021, a A$0 monetary threshold applies to acquisitions by foreign investors of interests in national security businesses and national security land. Acquisitions of interests in a "national security business" or "national security land" are referred to as national security actions. A business is a national security business if it is carried on wholly or partly within Australia, whether in anticipation of profit or gain, and it is a reporting entity (responsible entity or a direct interest holder) in relation to a critical infrastructure asset (within the meaning of the Security of Critical Infrastructure Act 2018 as enacted).

As Woodside is considered a reporting entity of a critical gas asset within the meaning of the Security of Critical Infrastructure Act 2018, it is considered a "national security business" under the FATA. Investments of a 10% or more (or less than 10% with an ability to influence, participate in or control the entity/business) interest by all foreign investors in a national security business must be notified to the Australian Government and require prior approval from the Australian Treasurer in accordance with the FATA. Accordingly, acquisitions of interests of 10% or more (or investments of less than 10% with an ability to influence, participate in or control the entity/business) in Woodside, would require prior approval from the Australian Treasurer.

6 Minority Shareholders

The Corporations Act also provides protection for minority shareholders where the conduct of a company's affairs or an act or omission (including a resolution of members or a class or members) by a company is contrary to the interests of the members as a whole, or oppressive to, unfairly prejudicial to, or unfairly discriminatory against a member or a group of members.

7 Substantial holdings

Under the Corporations Act, a person has a "substantial holding" if that person and his/her associates have a relevant interest in 5% or more of voting shares in a company. A person who begins to or ceases to have a substantial holding in a company or has a substantial holding in a company and there is movement in that holding by at least 1%, must give notice to the company and to the ASX. The contents of this notice are prescribed in section 671B(3) and (4) of the Corporations Act.

Under the Disclosure Guidance and Transparency Rules, specifically DTR 5, shareholders must notify a company of the percentage of voting rights they hold as shareholder (or hold or are deemed to hold through their direct or indirect holding of financial instruments) if, as a result of an acquisition or disposal of shares or financial instruments, the percentage of those voting rights reaches, exceeds or falls below 5%, 10%, 15%, 20%, 25%, 30%, 50% and 75%. This obligation is in addition to the obligation to notify Woodside and the ASX under the Corporations Act.

8 Australian disclosure requirements

Periodic disclosure

The Corporations Act and ASX Listing Rules set out the Australian periodic disclosure requirements that apply to Woodside. For example, Woodside must prepare and lodge half-year and full-year financial reports and must prepare and lodge an annual report to Woodside Shareholders.

Continuous disclosure

ASX Listing Rule 3.1 provides that once Woodside is aware or becomes aware of any information concerning it that a reasonable person would expect to have a material effect on the price or value of Woodside's securities, it must immediately tell ASX that information, subject to the limited exceptions outlined below.

Immediate disclosure under ASX Listing Rule 3.1 can only be delayed under ASX Listing Rule 3.1A if each of the following is satisfied:

(1) a reasonable person would not expect the information to be disclosed; and

(2) the information is confidential and ASX has not formed the view that the information has ceased to be confidential; and

(3) one or more of the following applies:

- (a) it would be a breach of a law to disclose the information;
- (b) the information concerns an incomplete proposal or negotiation;
- (c) the information comprises matters of supposition or is insufficiently definite to warrant disclosure;
- (d) the information is generated for internal management purposes of Woodside;
- (e) the information is a "trade secret."

Disclosure in relation to false markets

ASX Listing Rule 3.1B provides that if ASX considers that there is, or is likely to be, a false market in an entity's securities, and requests information from the entity to correct or prevent the false market, the entity must immediately give ASX that information.

Information must be given to ASX first

ASX Listing Rule 15.7 requires that an entity must not release information that is for release to the market to anyone until it has given the information to ASX and has received an acknowledgement from ASX that the information has been released to the market.

However, ASX Listing Rule 15.7.1 provides that an entity may release information that is for release to the market, if it becomes available outside the hours of operation of the ASX Market Announcements Office, to an overseas stock exchange that requires it. In that case, the entity must give the information to the ASX Market Announcement Office at the same time, together with advice that is has released it.

SEC Disclosure Requirements

Woodside is a "foreign private issuer" under the securities laws of the United States and the NYSE Listing Rules. Under the securities laws of the United States, "foreign private issuers" are subject to different disclosure requirements than U.S. registrants.

Woodside intends to take all actions necessary to maintain compliance as a foreign private issuer under the applicable corporate governance requirements of the Sarbanes-Oxley Act, the rules adopted by the SEC and NYSE listing standards. Subject to certain exceptions, the NYSE Listing Rules permit a "foreign private issuer" to comply with its home country rules in lieu of the listing requirements of the NYSE.

Additionally, because Woodside qualifies as a "foreign private issuer" under the Exchange Act, it is exempt from certain provisions of the securities rules and regulations in the United States that are applicable to U.S. domestic issuers, including: (i) the rules under the Exchange Act requiring the filing with the SEC of quarterly reports on Form 10-Q or current reports on Form 8-K; (ii) the sections of the Exchange Act regulating the solicitation of proxies, consents, or authorisations in respect of a security registered under the Exchange Act; (iii) the sections of the Exchange Act requiring insiders to file public reports of their stock ownership and trading activities and liability for insiders who profit from trades made in a short period of time; and (iv) the selective disclosure rules by issuers of material non-public information under Regulation FD.

Woodside will be required to file an annual report on Form 20-F within four months of the end of each fiscal year. Press releases relating to financial results and material events will also be furnished to the SEC on Form 6-K.

NYSE Disclosure Requirements

The NYSE Listing Rules also require listed companies to disclose, amongst other things, news or information which might reasonably be expected to materially affect the market for the listed company's securities.

Subject to certain exceptions, the NYSE Listing Rules permit a "foreign private issuer" to comply with its home country rules in lieu of the corporate governance requirements of the NYSE. Foreign private issuers listed on the NYSE must disclose in their Annual Report on Form 20-F any significant ways in which their corporate governance practices differ from those followed by U.S. domestic companies under the NYSE Listing Rules.

Tax Implications for certain BHP Shareholders

Part 20 *(Taxation)* of this Prospectus contains a general outline of the taxation implications for certain Eligible BHP Shareholders and BHP ADS Holders that are tax resident in Australia, the United Kingdom, or the United States in respect of the Implementation and holding Woodside Shares.

This does not constitute tax advice. This Prospectus does not take into account Eligible BHP Shareholders' or BHP ADS Holders' individual investment objectives, financial situation or needs. This Prospectus is not a complete analysis of all taxation laws which may apply in relation to the Implementation and holding Woodside Shares for Eligible BHP Shareholders and BHP ADS Holders. All Eligible BHP Shareholders and BHP ADS Holders should consult with their own independent taxation advisers regarding the taxation implications of the Merger given the particular circumstances which apply to them.

This outline relates solely to matters governed by, and should be interpreted in accordance with, the laws of the various countries as in force and as interpreted at 9:00am (AEDT) on the Last Practicable Date.

This outline does not take into account or anticipate changes in the law (by legislation or judicial decision) or practice (by ruling or otherwise) after that time. Future amendments to taxation legislation, or its interpretation by the courts or the taxation authorities may take effect retrospectively and/or affect the conclusions drawn.

9 Constitution and Certificate of Incorporation

The rights and liabilities attaching to the Woodside Shares (including the New Woodside Shares which will be issued as Share Consideration) are set out in the Woodside Constitution, and are also subject to the Corporations Act and ASX Listing Rules.

Approval for the issue of the New Woodside Shares for the purposes of ASX Listing Rule 7.1 (and for all other purposes) is being proposed at a meeting of Woodside Shareholders to be held on 19 May 2022. Woodside

Shareholders on the Woodside Share register as at 5.00pm (Perth time) on 17 May 2022 will be entitled to vote on the resolution, either in person at the meeting or by proxy. The resolution needs to be approved by a simple majority of the votes cast on the resolution.

The New Woodside Shares will be issued fully paid and will rank equally for dividends and other rights with existing Woodside Shares, with effect from their date of issue.

Under the Corporations Act, the Woodside Constitution has effect as a contract between:

- Woodside and each Woodside Shareholder;
- Woodside and each director and company secretary of Woodside; and
- a Woodside Shareholder and each other Woodside Shareholder.

Accordingly, if you hold Woodside Shares (including if you receive New Woodside Shares pursuant to the Merger), you are taken to receive them subject to the terms of the Woodside Constitution and you will be bound by the terms of the Woodside Constitution. The following is a non-exhaustive summary of the provisions of the Woodside Constitution, including the main rights and liabilities attaching to Woodside Shares. This summary does not purport to be exhaustive or to constitute a definitive statement of all of the rights and liabilities attaching to Woodside Shares. Those rights and liabilities involve complex questions of law arising from the interaction of the Woodside Constitution and statutory and common law requirements. Please see paragraph 28 of Part 21 *(Additional Information)* of this Prospectus for details on how to obtain a full copy of the Woodside Constitution.

Objects and purpose

The Woodside Constitution does not contain any limitations on Woodside's objects and purposes.

Powers of Woodside and Woodside Directors

General powers

Woodside may exercise in any manner permitted by the Corporations Act, any power which a public company limited by shares may exercise under that legislation. The business of Woodside is managed by or under the direction of the Woodside Directors. The Woodside Directors may exercise all the powers of Woodside except any powers that the Corporations Act or the Woodside Constitution requires Woodside to exercise in a general meeting.

Execution of documents

Woodside may execute a document with or without the common seal so long as the fixing of the seal is witnessed by, or the document is signed by, either two directors or a director and a company secretary of Woodside.

Share capital

Woodside in general meeting may reduce or alter its share capital in any manner allowed or provided for by the Corporations Act and the ASX Listing Rules. The Woodside Board may do anything which is required to give effect to any resolution authorising reduction or alteration of the share capital of Woodside. The ISIN of the Woodside Shares is currently AU000000WPL2 and is expected to change prior to Admission following Woodside's change of name.

As at the Last Practicable Date there were 983,980,823 Woodside Shares in issue and it is estimated that immediately following the Implementation there will be 1,898,749,771 Woodside Shares in issue[58]. The Woodside Shares have no par value. On Admission, all of the Woodside Shares will be fully paid or credited as fully paid.

Depositary Interests

On Admission, holders of Woodside Shares will be able to hold and transfer interests in Woodside Shares within CREST pursuant to a depositary interest arrangement established by Woodside. The Woodside Shares will not themselves be admitted to CREST; rather, the UK Depositary will issue the Depositary Interests in respect of underlying Woodside Shares.

[58] Based on number of Woodside Shares in issue as at the Last Practicable Date and assumes no additional Woodside Shares are issued between Last Practicable Date and Implementation.

The Depositary Interests are independent securities constituted under English law, which are held and transferred directly through the CREST system. Depositary Interests have the same ISIN as the underlying Woodside Shares and do not require a separate admission to trading on the LSE. The Depositary Interests were created and issued pursuant to a Deed Poll issued and executed by the UK Depositary.

Meetings of Woodside Shareholders and notices

Woodside Shareholders' rights to attend and vote at shareholder meetings are primarily prescribed by the Corporations Act and the Woodside Constitution. Subject to certain exceptions, each Woodside Shareholder is entitled to receive notice of, attend (whether or not entitled to vote) and vote at general meetings and to receive all notices and other documents required to be sent to Woodside Shareholders under the Woodside Constitution, the Corporations Act and ASX Listing Rules.

A general meeting of Woodside Shareholders must be called by a notice of at least 28 days of notice for a meeting of shareholders in accordance with the Corporations Act. The notice of meeting of Woodside Shareholders must be given to the ASX, each Woodside Shareholder (whether or not such shareholder is entitled to vote at the meeting), each Woodside Director (other than an alternate director) and Woodside's auditor. The notice must set out the date and time of the meeting (if virtual meeting technology is to be used in holding the meeting, that virtual meeting technology must be reasonable and allow Woodside Shareholders to exercise orally and in writing any rights of Woodside Shareholders to ask questions and make comments), the general nature of the business of the meeting, the date and time at which persons will be taken for the purpose of the meeting to hold Woodside Shares and any other information or documents specified by the Corporations Act and the ASX Listing Rules.

Woodside may give a notice of meeting to Woodside Shareholders by serving it personally, sending it by post to, or leaving it at, the address shown in the Woodside Register or any other address, or by sending it by fax or electronically to the address provided by the Woodside Shareholder for the purpose of giving notices.

Woodside must hold an annual general meeting in accordance with the Corporations Act and the ASX Listing Rules. Under the Corporations Act, every public company that has more than one member must hold an annual general meeting at least once in each calendar year, and within five months after the end of its financial year.

Voting rights

Subject to any rights or restrictions attached to Woodside Shares, the terms of the Woodside Constitution and voting exclusions under the ASX Listing Rules or the Corporations Act, each outstanding Woodside Share entitles the Woodside Shareholder to one vote on each matter properly submitted to Woodside Shareholders for their vote. At a general meeting of Woodside Shareholders, every Woodside Shareholder entitled to vote in person or by proxy, attorney or representative has:

- one vote on a show of hands; and
- one vote on a poll for every Woodside Share held.

The quorum for a meeting of Woodside Shareholders is three eligible Woodside Shareholders entitled to vote. If more than one joint holder of a Woodside Share is present at a meeting in person or by proxy, attorney or representative and tenders a vote, the vote of the Woodside Shareholder named first in the Woodside Register will be accepted to the exclusion of the others. Each Woodside Shareholder may vote in person or by proxy. A proxy appointed to attend and vote may exercise the rights of the Woodside Shareholder on the basis and subject to the restrictions provided in the Corporations Act but not otherwise, but may not cast a vote by direct vote (i.e. by casting a vote by sending it to Woodside before the meeting).

A proxy is not revoked by the appointing Woodside Shareholder attending and taking part in the meeting, unless the appointing Woodside Shareholder actually votes at the meeting on the resolution for which the proxy is proposed to be used. A resolution at a general meeting must be decided on a show of hands unless a poll is demanded. A poll may be demanded on any resolution (except a resolution concerning the election of the chair of the meeting or, unless the chair otherwise determines, the adjournment of a meeting).

If the votes on a proposed resolution are equal, the chair of the meeting has a casting vote.

Dividend rights and distributions in kind

The Woodside Directors may pay any dividend (including an interim, final or special dividend) that they think the financial position of Woodside justifies, and fix the date for payment.

The Woodside Directors may direct payment of a dividend by the distribution of specific assets (including paid-up shares of Woodside or of another body corporate) either generally or to specific Woodside Shareholders.

The Woodside Directors may implement a dividend reinvestment plan on any terms as they think fit, under which any dividend due to Woodside Shareholders who participate in the plan may be applied in subscribing for Woodside Shares, subject to the rules of the relevant dividend reinvestment plan.

Redemption and preferences

Woodside may issue preference shares, but Woodside has not issued and currently has no intention to issue any preference shares.

As at the date of this Prospectus, all Woodside Shares have the same rights and preferences. Woodside Shareholders are not entitled to any pre-emptive or preferential rights to acquire additional Woodside Shares.

Issue of further Woodside Shares

Subject to the Corporations Act, ASX Listing Rules and the Woodside Constitution, Woodside may issue, allot or grant options over or rights in respect of, or otherwise dispose of, shares in Woodside or other securities of Woodside and decide, amongst others, the terms, rights and restrictions of the securities, as determined by the Woodside Board from time to time.

Transfer of Woodside Shares

Subject to the Woodside Constitution and the rights attached to Woodside Shares under ASX Listing Rules or the Corporations Act or other applicable legislation, Woodside Shareholders may transfer Woodside Shares by any means permitted by the Corporations Act or by applicable law.

Woodside Directors may refuse to register a transfer of Woodside Shares in circumstances set out in the Woodside Constitution (including but not limited to, those permitted under ASX Listing Rules or ASX Settlement Operating Rules). Where Woodside Directors refuse to register a transfer, Woodside must give written notice of the refusal and the reasons for refusal within the maximum period permitted by the ASX Listing Rules.

Proportional takeover provisions

The Woodside Constitution requires Woodside Shareholder approval in relation to any proportional takeover bid. These provisions will cease to apply unless they are renewed by Woodside Shareholders passing a special resolution by the third anniversary of either the date that those rules were adopted or the date those rules were last renewed (the rules were adopted on 2 May 2019).

Variation of rights

The Corporations Act provides that the rights attached to a class of shares may be varied or cancelled only:

- with the written consent of members with at least 75% of the votes of the affected class; or
- by special resolution passed at a meeting of the holders of the issued shares of that class.

Number of Woodside directors

Unless otherwise determined by Woodside Shareholders in general meeting, Woodside must have at least 3 directors and not more than 12 directors. The Woodside Directors may from time to time determine the number of directors but the maximum applying at any time cannot be reduced except with the approval of Woodside Shareholders in general meeting.

Subject to the Woodside Constitution, the Corporations Act and the number of directors as determined by the Woodside Board (being a number of not more than 12 unless otherwise approved by Woodside Shareholders in general meeting), Woodside Shareholders may by ordinary resolution elect any natural person as a director. Any director appointed by the Woodside Board may hold office only until the next annual general meeting during which if no election of Directors is schedule to occur then one director must retire from office at the annual general meeting.

Removal and resignation of Woodside Directors

Woodside Directors may be removed in accordance with Corporations Act and ASX Listing Rules. The Corporations Act provides that Woodside may by ordinary resolution passed at a general meeting remove any Director, and if thought fit, appoint another person in place of that Director.

A Woodside Director may resign from office by giving Woodside notice in writing.

Director remuneration

As remuneration for services, each Woodside Non-Executive Director is to be paid or provided with the amount determined by the Woodside Board, which will be payable or provided at the time and in the manner determined by the Woodside Board, but the aggregate remuneration paid or provided to all the Woodside Non- Executive Directors in any financial year may not exceed an amount fixed by Woodside in general meeting

Any Woodside Director who devotes special attention to the business of Woodside, or who otherwise performs services which in the opinion of the Woodside Board are outside the scope of the ordinary duties of a director, or who at the request of the Woodside Board engages in any journey on the business of Woodside, may be paid extra remuneration as determined by the Woodside Board, subject to the terms of the Woodside Constitution.

The ASX Listing Rules provide limited exceptions to issuing or permitting the issue of equity securities to an executive director made, or taken to have been made, in circumstances without the approval of the holders of the entity's ordinary securities. In addition, the ASX Listing Rules provide that any issuance, or agreement to issue, equity securities under an employee incentive scheme count for the purposes of calculation of the maximum percentage of equity securities that can be issued in any 12-month period without the approval of the holders of the entity's ordinary shares unless the incentive scheme itself has been approved by those holders within the prior three year period.

Disqualification and retirement of Woodside Directors

A Woodside Director (other than a Woodside Director who is the Managing Director) must retire from office at the third annual general meeting after the Woodside Director was elected or most recently re-elected.

An election of Woodside Directors must be held at the annual general meeting each year. If no election of Woodside Directors is scheduled to occur at an annual general meeting, then the Woodside Director longest in office since last being elected must retire.

The office of a Woodside Director is vacated on the Woodside Director:

(a) becoming an insolvent under administration, suspending payment generally to creditors or compounding with or assigning such director's estate for the benefit of creditors;

(b) becoming a person of unsound mind or a person who is a patient under laws relating to mental health or whose estate is administered under laws relating to mental health;

(c) being absent from meetings of the Woodside Board during a period of three consecutive calendar months without leave of absence from the Woodside Board where the Woodside Board has not, within 14 days of having been served by the company secretary with a notice giving particulars of the absence, resolved that leave of absence be granted;

(d) resigning office by notice in writing to Woodside;

(e) being removed from office under the Corporations Act

(f) being prohibited from being a Woodside Director under the Corporations Act; or

(g) themselves, or on any partner, employer or employee of the Director, accepting or holding the office of auditor of Woodside.

The office of a Woodside Director who is an employee of Woodside or any of its subsidiaries becomes vacant on the Woodside Director ceasing to be employed but the person concerned is eligible for reappointment or re-election as a Director of Woodside in accordance with the Woodside Constitution.

Conflict of interest

A Woodside Director may:

(1) hold any office or position (except as auditor) in Woodside, on any terms and at a remuneration as the Woodside Board approves not being a commission on or percentage of turnover; or

(2) be or become a director or hold an office or position in any corporation promoted by Woodside, or in which Woodside may be interested, or any other corporation or organisation,

and the Woodside Director is not accountable for any benefits received as a shareholder, director or holder of any other office or position in any other corporation or organisation.

Each Woodside Director must comply with the Corporations Act in relation to:

(1) disclosure of matters involving material personal interests and voting on matters involving material personal interests; and

(2) being present, and voting, at a Woodside Board meeting that considers a matter in which the Director has a material personal interest.

If a Woodside Director discloses their interest before the transaction is entered into, subject to the Corporations Act:

(1) a Woodside Director may be counted in a quorum at a Woodside Board meeting that considers, and may vote on, any matter in which that Director has an interest;

(2) Woodside may proceed with any transaction that relates to the interest;

(3) the Woodside Director may participate in the execution of any relevant document by or on behalf of Woodside;

(4) the Woodside Director may retain benefits under the transaction even though the Director has the interest; and

(5) Woodside cannot avoid the transaction merely because of the existence of the Woodside Director's interest.

A Woodside Director must give to Woodside the information which Woodside is required to disclose to ASX in respect of:

(1) notifiable interests of the Director; and

(2) changes to the notifiable interests of the Director.

Alternate Woodside Directors

Subject to the Woodside Constitution and with the approval of a majority of the other Woodside Directors, a Woodside Director may appoint a person as an alternate director for a stated period or until the happening of a specified event. The alternate Woodside Director may be removed or suspended from office on receipt of notice from the appointing Woodside Director.

Proceedings of Woodside Directors

The Woodside Board may meet, adjourn and otherwise regulate their meetings as they think fit. The Woodside Board may at any time, and the company secretary on the request of any Woodside Director must, convene a Board meeting. Unless otherwise determined by the Woodside Board, three Woodside Directors form a quorum. Subject to the Corporations Act, an interested Woodside Director is to be counted in a quorum despite the interest.

A resolution of Woodside Directors is passed if more votes are cast in favour of the resolution than against it. Subject to the Corporations Act, the ASX Settlement Operating Rules, and the ASX Listing Rules the chairperson of that meeting (except when only two Woodside Directors are present or except when only two Woodside Directors are competent to vote on the question then at issue) has a second or casting vote on that resolution.

A resolution in writing signed by all Woodside Directors or a resolution in writing of which notice has been given to all Woodside Directors and which is signed by a majority of the Woodside Directors entitled to vote on the resolution (not being less than the number required for a quorum at a meeting of the Woodside Board) is as valid as if it had been passed at a meeting of the Woodside Board duly called and constituted and may consist of several documents in the same form each signed by one or more of the Woodside Directors.

Chair

The Woodside Board may elect a chair or deputy chair of its meetings and determine the period for which each is to hold office. If no chair or deputy chair is elected or if at any meeting the chair and the deputy chair are not present at the time specified for holding the meeting, the directors present may choose one of their number to be chair of the meeting.

Meetings by telephone or other means of communication

The Woodside Board may meet either in person, by telephone, by video conferencing facility or by using any other technology consented to by all the Woodside Directors. A consent may be a standing one. A Woodside Director may only withdraw consent within a reasonable period before the meeting. A meeting conducted by telephone, video conference or other means of communication is deemed to be held at the place agreed on by the Woodside Directors attending the meeting if at least one of the Woodside Directors present at the meeting was at that place for the duration of the meeting.

Woodside Managing Director

The Woodside Board may appoint a person as a managing director either for a specified term (but not for life) or without specifying a term. The Woodside Board may delegate any of the powers of the Woodside Board to the Managing Director on the terms and subject to any restrictions the Woodside Board decides, so as to be concurrent with, or to the exclusion of, the powers of the Woodside Board. The Woodside Board can revoke the delegation at any time.

Woodside Company Secretary

The Woodside company secretary is to be appointed by the Woodside Directors.

Officer's indemnity

Woodside must, to the extent the person is not otherwise indemnified, indemnify every officer and employee of Woodside and its wholly owned subsidiaries and may indemnify its auditor against a liability incurred as a Woodside officer, employee or auditor to a person (other than Woodside or a related body corporate) including a liability incurred as a result of appointment or nomination by Woodside or any subsidiary as a trustee or as an officer of another corporation or body (including a statutory authority), unless the liability arises out of conduct involving a lack of good faith.

Capitalising profits

Woodside may capitalise and distribute among Woodside Shareholders undivided profits and other amounts available for distribution. Woodside Shareholders are entitled to participate in that capital distribution if entitled to receive dividends and in the same proportions.

Reduction of capital

Woodside in general meeting may reduce or alter its share capital in any manner allowed or provided for by the Corporations Act and the ASX Listing Rules. An equal reduction of capital must be approved by Woodside Shareholders by way of an ordinary resolution. A selective reduction of capital must be approved by Woodside Shareholders by way of a special resolution.

Winding up

If Woodside is wound up, a liquidator may divide among all or any of the contributories, as the liquidator thinks fit, in specie or kind, any part of the assets of Woodside, and may vest any part of the assets of Woodside in trustees on any trusts for the benefit of all or any of the contributories as the liquidator thinks fit. Any division may be otherwise than in accordance with the legal rights of the contributories and, in particular, any class may be given preferential or special rights or may be excluded altogether or in part, but if any division otherwise than in accordance with the legal rights of the contributories is determined, any contributory who would be prejudiced by the division has a right to dissent and ancillary rights as if the determination were a special resolution passed under the Corporations Act relating to the sale or transfer of Woodside's assets by a liquidator in a voluntary winding up.

10 Major Shareholders

As at the Last Practicable Date, Woodside is aware of the following persons who (together with their associates), directly or indirectly, hold interests in 5% or more of the Woodside Shares or voting rights as notified to Woodside under the Corporations Act. The table below also shows what these interests are expected to be on Admission, which will be following the issuance of the New Woodside Shares as part of Implementation:

Name	Number of Woodside Shares (pre-Implementation)	Percentage of issued share capital (pre-Implementation)[1]	Anticipated number of Woodside Shares (post-Implementation)	Anticipated percentage of issued share capital on Admission (post-Implementation)[2]
Blackrock Group (Blackrock Inc. and subsidiaries)	57,411,550[3]	5.83	120,866,917[4]	6.37
State Street Corporation and subsidiaries	50,409,641[5]	5.12	91,004,737[6]	4.79[2 3]

1 Based on number of Woodside Shares on issue as at the Last Practicable Date.

2 Based on the estimated number of Woodside Shares on issue at Implementation being 1,898,749,771.

3 This information is derived from the Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 30 May 2019, indicating ownership of Woodside's shares as of such date.

4 This information is derived from the Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 30 May 2019, indicating ownership of Woodside's shares as of such date and a Notice of Change of Interests of Substantial Holder filed by the Blackrock Group with the ASX on 31 January 2022, indicating ownership of BHP shares as of such date.

5 This information is derived from the Notice of Initial Substantial Holder filed by State Street Corporation with the ASX on 8 November 2021, indicating ownership of Woodside's shares as of such date.

6 This information is derived from the Notice of Initial Substantial Holder filed by State Street Corporation with the ASX on 8 November 2021, indicating ownership of Woodside's shares as of such date and information provided by BHP to Woodside dated 14 February 2022 relating to the number of shares held by State Street Corporation.

Save as disclosed above, insofar as is known to the Directors, there is no other person who is or will be immediately following Admission, directly or indirectly, interested in 5% or more of the issued share capital of the Merged Group, or any other person who can, will or could, directly or indirectly, jointly or severally, exercise control over the Merged Group.

The Directors have no knowledge of any arrangements the operation of which may at a subsequent date result in a change of control of Woodside

Substantial Shareholders do not have voting rights that differ from those of any other holders of Woodside Shares.

11 Directors' and Key Management Personnel's Interests

At the Last Practicable Date, the Shares held by the Directors and Key Management Personnel (all of which are held beneficially unless otherwise stated) are as follows. This does not include Restricted Shares which are set out below at paragraph 14 of Part 21 (*Additional Information)* of this Prospectus:

Name	Number of Shares	Percentage of existing total issued share capital of Woodside[59]	Expected percentage of total issued share capital of the Merged Group following Implementation
Executive Director			
Meg O'Neill	147,463	0.0%	0.0%
Non-Executive Directors			
Richard Goyder, AO	23,634	0.0%	0.0%
Larry Archibald	13,524	0.0%	0.0%
Frank Cooper, AO	14,242	0.0%	0.0%
Swee Chen Goh	13,424	0.0%	0.0%
Ian Macfarlane	10,637	0.0%	0.0%
Christopher Haynes, OBE	15,372	0.0%	0.0%
Ann Pickard	15,870	0.0%	0.0%
Gene Tilbrook	7,949	0.0%	0.0%
Sarah Ryan	12,599	0.0%	0.0%
Ben Wyatt	898	0.0%	0.0%
Key Management Personnel			
Graham Tiver	—	0.0%	0.0%
Shaun Gregory	18,648	0.0%	0.0%
Fiona Hick	10,994	0.0%	0.0%

Details of outstanding incentive awards granted to the CEO and other Key Management Personnel are set out in paragraph 14 of Part 21 (*Additional Information)* of this Prospectus. The minimum shareholding requirements policy requires the CEO and Key Management Personnel to have acquired and maintained Woodside Shares for a minimum total purchase price of at least 100% of their fixed remuneration after a period of five years and, in the case of the CEO, a minimum of 200% of fixed remuneration.

Non-Executive Directors are required to have acquired shares for a total purchase price of at least 100% of their pre-tax annual fee after five years on Woodside Board. The Non-Executive Directors may utilise the NEDSP to acquire the Woodside Shares on market at market value. As the Shares are acquired with net fees the Shares in the NEDSP are not subject to any forfeiture conditions.

Woodside's own equity instruments, which are reacquired for later use in employee share-based payment arrangements (reserved shares), are deducted from equity. No gain or loss is recognised in the income statement on the purchase, sale, issue or cancellation of Woodside's own equity instruments.

12 Directors' and Key Management Personnel's service agreements

CEO and Key Management Personnel – service agreements

The CEO and each Key Management Personnel has entered into a service agreement. The below table summarises the key contractual provisions. The total remuneration paid to, or in respect of, the CEO and each Key Management Personnel is set out in the table in paragraph 13 of this Part 21 (*Additional Information*) of this Prospectus below.

[59] Based on 983,980,823 shares outstanding which is the number of issued and fully paid Woodside Shares as of the Last Practicable Date

	Employing Company	Contract date	Contract duration	Termination notice period-company	Termination notice period executive
Executive Director					
Meg O'Neill (CEO)	Woodside Energy Ltd	1 November 2021	Unlimited	6 months	6 months
Key Management Personnel					
Graham Tiver	Woodside Energy Ltd	14 December 2021	Unlimited	6 months	6 months
Shaun Gregory	Woodside Energy Ltd	1 June 2011	Unlimited	6 months	3 months
Fiona Hick	Woodside Energy Ltd	1 June 2016	Unlimited	6 months	3 months

Notes:

(1) Woodside may choose to terminate the contract immediately by making a payment in lieu of notice equal to the fixed remuneration the CEO or the Key Management Personnel (as applicable) would have received during the "Company Notice Period". In the event of termination for serious misconduct or other nominated circumstances, the CEO or the Key Management Personnel (as applicable) is not entitled to this termination payment. Any payments made in the event of a termination of an executive contract will be consistent with the Corporations Act.

(2) On termination of employment, the CEO or the Key Management Personnel (as applicable) will be entitled to the payment of any fixed remuneration calculated up to the termination date, any leave entitlement accrued at the termination date and any payment or award permitted under the EIS and Equity Award Rules. The CEO and the Key Management Personnel are restrained from certain activities for specified periods after termination of their employment in order to protect Woodside's interests.

Non-Executive Directors – letters of appointment

All new non-executive directors are required to sign a letter of appointment which sets out the key terms and conditions of their appointment, including duties, rights and responsibilities, the time commitment envisaged and the Board's expectations regarding their involvement with committee work. On resignation, retirement or removal, non-executive directors are entitled to payment of any directors' fees calculated up to the end date. Non-executive directors do not receive any other benefits on resignation, retirement or removal.

Induction training is provided to all new directors. It includes a comprehensive induction manual, discussions with the CEO and senior executives and the option to visit Woodside's principal operations either upon appointment or with the Board during its next site tour. The induction materials and discussions include information on Woodside's strategy, culture and values; key corporate and Board policies; the company's financial, operational and risk management position; the rights and responsibilities of directors; the role of the Board and its committees; meeting arrangements; and if required, key accounting matters and directors' responsibilities in relation to Woodside's financial statements.

Questionnaires are completed annually to assess each director's skills and knowledge required to discharge their obligations to the company. Woodside considers at least annually the need for new and existing directors to undertake professional development to develop and maintain the skills and knowledge needed to perform their role as directors effectively and provides directors who require professional development the opportunity to develop and maintain the required skills and knowledge. Directors attend continuing professional education sessions including industry seminars and approved education courses which are paid for by the company, where appropriate. In addition, the company provides the Board with regular educational information papers and presentations on industry related matters and new and emerging developments with the potential to affect Woodside.

13 Directors' and Key Management Personnel's remuneration

Remuneration Policy

Woodside aims to deliver affordable energy solutions and superior outcomes to stakeholders. To do so, Woodside must be able to attract and retain executive capability in a globally competitive market. The Woodside Board structures remuneration so that it rewards those who perform, is valued by executives, and is strongly aligned with Woodside's corporate governance framework, strategic direction and the creation of value for all stakeholders through efficient and safe operations and the development of new, value-creating projects.

Executive remuneration is comprised of two components (further details of which are set out in paragraph 14 of Part 21 (*Additional Information)* below):

- Fixed Annual Reward ("**FAR**") is determined having regard to the scope of the executive's role and their level of knowledge, skills and experience.
- Variable Annual Reward ("**VAR**") at target is structured to reward the executives for achieving challenging yet realistic targets set by the Board which deliver short-term and long-term growth for Woodside. VAR aligns shareholder and executive remuneration outcomes by ensuring a significant portion of executive remuneration is at risk, while rewarding performance.

Executive remuneration is reviewed annually, having regard to the accountabilities, experience, and performance of the individual. FAR and VAR are compared against domestic and international competitors at target, to maintain Woodside's competitive advantage in attracting and retaining talent and to ensure appropriate motivation is provided to executives to deliver on Woodside's strategic objectives.

Total Key Management Personnel's remuneration and benefits

The following table details the total remuneration of the Key Management Personnel for the year ended 31 December 2021, including any contingent or deferred compensation and any benefits in kind, for their services, in all capabilities, to Woodside.

The remuneration and benefits reported are presented in the table in U.S. dollars, unless otherwise stated. This is consistent with the functional and presentation currency of Woodside. Compensation for Australian-based employees is paid in Australian dollars and, for reporting purposes, converted to U.S. dollars based on the applicable exchange rate at the date of payment. Valuation of equity awards is converted at the spot rate applying when the equity award is granted.

Compensation of CEO and Key Management Personnel for the year ended 31 December 2021

	Fixed Annual Reward			Variable Annual Reward						
	Short-term		Post	Cash	Share-based payments			Total remuneration[60]		Performance related [61]
Name	Salaries[62]	Benefits[63]	Super annuation[64]	Cash[65]	Share plans[66]	Long service leave[67]	Benefits on termination	(USD)	(A$)	%
Executive Director										
Meg O'Neill (CEO)	1,431,531	52,614		337,421	1,515,992	129,123		3,466,681	4,633,501	53
Key Management Personnel										
Graham Tiver	0	0	0	0	0	0	0	0	0	0
Shaun Gregory	588,690	15,788	29,403	261,699	557,279	18,260	—	1,471,119	1,971,787	56
Fiona Hick	540,368	29,989	22,742	128,875	390,418	11,742	—	1,124,134	1,503,402	46

Non-Executive Director remuneration structure

Non-Executive Director remuneration consists of base Woodside Board fees and committee fees, plus statutory superannuation contributions or payments in lieu (currently 10%). Other payments may be made for additional

60 The total remuneration in AUD is converted from USD using the average exchange rate for the period. This non-IFRS information is included for the purposes of showing the total annual cost of benefits to Woodside in Australian dollars for the service period

61 Performance related outcome percentage is calculated as total Variable Annual Reward divided by the total USD remuneration figure.

62 Includes fees and allowances. Sums are in USD.

63 Sums are in USD. Reflects the value of allowances and non-monetary benefits (including relocation, travel, car parking and any associated fringe benefit tax)

64 Contributions from the company to superannuation. Sums are in USD.

65 The amount represents the cash incentive earned in the respective year, which is actually paid in the following year. Amounts were translated to USD using the closing spot rate on 31 December. Sums are in USD.

66 'Share plans' incorporate all equity-based plans (including legacy equity plans previously utilised by Woodside). In accordance with the requirements of AASB 2 Share-based Payment, the fair value of rights as at their date of grant has been determined by applying the Black-Scholes option pricing technique or applying the binomial valuation method combined with a Monte Carlo simulation. The fair value of rights is amortised over the vesting period from the commencement of the service period, such that 'total remuneration' includes a portion of the fair value of unvested equity compensation during the year. The portion of the expense relating to the 2021 EIS has been measured using estimated fair values. The amount included as remuneration is not related to or indicative of the benefit (if any) that individual Senior Executives may ultimately realise should these equity instruments vest. Sums are in USD.

67 Sums are in USD.

services outside the scope of Woodside Board and Committee duties. Non-Executive Directors do not earn retirement benefits other than superannuation and are not entitled to any form of performance-linked remuneration in order to preserve their independence.

The below table shows the annual base Woodside Board and committee fees for Non-Executive Directors. In addition to these fees, Non-Executive Directors are entitled to reimbursement of reasonable travel, accommodation and other expenses incurred attending meetings of the Board, committees or shareholders, or while engaged on Woodside business. Non-Executive Directors are not entitled to compensation on termination of their directorships. An allowance is paid to any Non-Executive Director required to travel internationally to attend Woodside Board commitments, compensating for factors related to long-haul travel. Where travel is between six and ten hours, an allowance of A$5,000 gross per trip is paid. Where travel exceeds 10 hours, an allowance of A$10,000 gross per trip is paid. Woodside Board fees are not paid to the CEO, as the time spent on Woodside Board work and the responsibilities of Woodside Board membership are considered in determining the remuneration package provided as part of the normal employment conditions.

Annual base fee

Position	Woodside Board (A$)	Audit & Risk Committee (A$)	Human Resources & Compensation Committee (A$)	Sustainability Committee (A$)	Nominations & Governance Committee (A$)
Chair of the Woodside Board	723,300				
Non-Executive Directors	219,178				
Committee chair		59,360	52,000	47,400	Nil
Committee member		31,964	26,500	23,700	Nil

Notes:

1. Non-Executive Directors receive Woodside Board and committee fees plus statutory superannuation (or payments in lieu where statutory superannuation is not required to be paid).
2. The fees received by Chair of the Woodside Board are inclusive of committee work.
3. The fees received by Non-Executive Directors mean the fees paid to Non-Executive Directors other than the Chair.
4. The fees received from Human Resources & Compensation Committee are annual fees from 1 July 2018, the fees received from Woodside Board and other committees are annual fees from 1 July 2019.
5. Other benefits for NEDs include due diligence fees paid to Frank Cooper, Ben Wyatt and Larry Archibald of A$20,000 in FY2022 (FY2021; A$20,000).

The following table provides a breakdown of the components of the remuneration for each Non-Executive Director for the year ended 31 December 2021, including any contingent or deferred compensation and any benefits in kind, for their services, in all capabilities, to Woodside:

Name	Fees (US$)	Woodside contributions to superannuation (US$)	Total (US$)
Richard Goyder, AO	578,950	16,990	595,940
Larry Archibald	241,462	—	241,462
Frank Cooper, AO	244,013	22,327	266,340
Swee Chen Goh	223,680	—	223,680
Christopher Haynes, OBE	226,447	—	226,447
Ian Macfarlane	217,522	4,423	221,945
Ann Pickard	241,472	—	241,472
Sarah Ryan	206,330	20,117	226,447
Gene Tilbrook	227,575	22,189	249,764
Ben Wyatt	129,586	16,082	145,668

14 Incentive Arrangements

14.1 CEO and other Senior Executive incentive arrangements

Woodside's remuneration structure for the CEO and other Senior Executives is comprised of two components:

Fixed Annual Reward	Variable Annual Reward
• Based upon the scope of the executive's role and their individual level of knowledge, skill and experience. • Benchmarked for competitiveness against domestic and international peers to enable Woodside to attract and retain superior executive capability.	• Executives are eligible to receive a single variable reward linked to challenging individual and company annual targets set by the Woodside Board. • 12.5% of the variable reward is paid in cash. • 27.5% is allocated in Restricted Shares, subject to a three-year deferral period. • 30% is allocated in Restricted Shares, subject to a five-year deferral period. • 30% is allocated in Performance Rights which are subject to a RTSR test five years after the date of grant; with one-third tested against a comparator group that comprises the ASX 50 index and the remaining two-thirds against a group of international oil and gas companies determined by the Woodside Board.

The key VAR features are summarised below:

Allocation methodology	Restricted Shares and Performance Rights are allocated using a face value allocation methodology. The number of Restricted Shares and Performance Rights is calculated by dividing the value by the VWAP in December each year.
Dividends	Executives are entitled to receive dividends on Restricted Shares. No dividends are paid on Performance Rights prior to vesting. For Performance Rights that do vest, a dividend equivalent payment will be paid by Woodside for the period between allocation and vesting.
Clawback provisions	The Woodside Board has the discretion to reduce unvested entitlements including where: an executive has acted fraudulently or dishonestly or is found to be in material breach of their obligations; there is a material misstatement or omission in the financial statements; or the Woodside Board determines that circumstances have occurred that have resulted in an unfair benefit to the executive.
Control event	The Woodside Board has the discretion to determine the treatment of any EIS award on a change of control event. If a change of control occurs during the 12-month performance period, an executive will receive at least a pro-rata cash payment in respect of the unallocated cash and Restricted Share components of the EIS award for that year, assessed at target. If a change of control occurs during the vesting period for equity awards, Restricted Shares will vest in full whilst Performance Rights may, at the discretion of the Woodside Board, vest on an at least pro-rata basis.
Cessation of employment	During a performance period, should an executive provide notice of resignation or be terminated for cause, no EIS award will be provided. In any other case, Woodside will have regard to performance against target and the portion of the performance period elapsed in determining the form of any EIS award.
No retesting	There will be no retest applied to EIS awards. Performance Rights will lapse if the required RTSR performance is not achieved at the conclusion of the five-year period.

As at the Last Practicable Date, the Restricted Shares, Performance Rights and VPRs held by the Directors and Key Management Personnel (all of which are held beneficially unless otherwise stated) are as follows:

Summary of CEO and Key Management Personnel's Equity Incentives (as at the Last Practicable Date)

Name	Type of equity	Rights allocated under the EIS and EIP (VPR and Performance Rights)	Rights allocated under the SWEP	Restricted Shares Granted
M O'Neill	**Rights**	55,366		
	Shares			82,189
G Tiver	**Rights**	—	124,381	—
	Shares	—		—
S Gregory	**Rights**	58,976		
	Shares			94,978
F Hick	**Rights**	49,053		
	Shares			73,086

14.2 Employee incentive arrangements

Woodside provides employees with the opportunity to participate in ownership of shares in the company and uses equity to support a competitive base remuneration position. This section sets out the employee equity incentives currently in issue and the details of equity incentives held by Senior Executives. In addition to the plans set out below, the Board may approve the discretionary awards of Restricted Shares, Performance Rights or Equity Rights to other executives and employees.

Executive Incentive Scheme

The EIS was introduced in 2018. The scheme remunerates executives for delivering results against measurable criteria aimed at safe, efficient operations, delivery of new projects and an effective financial structure. Performance Rights and Restricted Shares are awarded under the EIS.

Each Senior Executive's award is based upon two weighted components: individual performance against challenging KPIs (30%) and the company's performance against the Corporate Scorecard (70%). This results in an individual performance factor (IPF) which ranges from 0 to 1.6 for Senior Executives. The Corporate Scorecard targets and individual KPIs are designed to promote short- and long-term shareholder value. Performance against individual KPIs is assessed by the Board in the case of the CEO, and by the CEO and the Human Resources & Compensation Committee of the Woodside Board in the case of Senior Executives. Exceeding targets may result in an increased award, whereas under-performance will result in a reduced award. The minimum award that a Senior Executive can receive is zero if the performance conditions are not achieved. The decision to pay or allocate an EIS award is subject to the overriding discretion of the Board, which may adjust outcomes in order to better reflect shareholder outcomes, and company or management performance.

During a performance period, should a Senior Executive provide notice of resignation or be terminated for cause, no EIS award will be provided. In any other case, Woodside will have regard to performance against target and the portion of the performance period elapsed in determining the form of any EIS award.

During a vesting period, should a Senior Executive provide notice of resignation or be terminated for cause, any EIS award will be forfeited or lapse. In any other case, any Restricted Shares will vest in full from a date determined by the Board while any Performance Rights will remain on foot and vest in the ordinary course subject to the satisfaction of applicable conditions. The Board will have discretion to accelerate the vesting of unvested equity awards, subject to termination benefits laws.

Restricted Shares

Restricted Shares are existing Woodside Shares that are awarded to Senior Executives. No amount is payable by the executive on the grant or vesting of a Restricted Share. An award of Restricted Shares is divided into two tranches. The first tranche is 27.5% of the award and subject to a three-year deferral period. The second tranche is 30% of the award and subject to a five-year deferral period. There are no further performance conditions attached to these awards. This element creates a strong retention proposition for Senior Executives as vesting is subject to employment not being terminated with cause or by resignation during the deferral period. The deferral ensures that awards remain subject to fluctuations in share price across the three and five-year periods, which is intended to reflect the sustainability of performance over the medium- and long-term and support increased alignment between Senior Executives and Shareholders. As at 24 March 2022, Woodside had 1,982,924 unvested Restricted Shares outstanding.

Performance Rights

Performance Rights are awarded to Senior Executives and are divided into two portions with each portion subject to a separate RTSR performance hurdle tested over a five-year period. Performance is tested after five years as Woodside operates in a capital-intensive industry with long investment timelines. For each award of Performance Rights, one-third is tested against a comparator group that comprises the entities within the ASX 50 index. The remaining two-thirds is tested against an international group of oil and gas companies. RTSR outcomes are calculated by an external adviser on or after the fifth anniversary of the allocation of the Performance Rights. The outcome of the test is measured against the schedule below. For EIS awards, any Performance Rights that do not vest will lapse and are not retested.

Woodside RTSR percentile position within peer group	Vesting of Performance Rights
Less than 50th percentile	No vesting
Equal to 50th percentile	50% vest
Vesting between the 50th and 75th percentile	Vesting on a pro-rata basis
Equal to or greater than 75th percentile	100% vest

Executive Incentive Plan ("EIP")

The EIP is a legacy plan which operated as Woodside's Senior Executive incentive framework until the end of 2017, after which the Board introduced the EIS. Eligible Senior Executives were granted Variable Pay Rights (VPRs). Awards were divided into two portions with each portion subject to a separate RTSR performance hurdle tested over a four-year period. One-third of an award is tested against a comparator group that comprises the entities within the ASX 50 index. The remaining two-thirds is tested against an international group of oil and gas companies. RTSR outcomes are calculated by an external adviser on the fourth anniversary of the allocation. For plans awarded from 2017 onwards, any VPRs that do not vest will lapse and are not retested. Plans awarded prior to 2017 are allowed for a retest in the following year. VPRs that do not vest following the re-test will lapse.

Woodside Equity Plan ("WEP")

The WEP is available to all permanent employees except EIS participants. The purpose of the WEP is to enable eligible employees to build up a holding of equity in the company as they progress through their career at Woodside.

The number of Equity Rights ("**ERs**") offered to each eligible employee is determined by the Board and based on individual performance as assessed under the performance review process. There are no further ongoing performance conditions from the date of grant. The linking of performance to an allocation allows Woodside to recognise and reward eligible employees for high performance.

Each ER entitles the participant to receive a Woodside share on the vesting date three or five years after the effective grant date.

For offers prior to 2019, each ER entitled the participant to receive a Woodside Share on the vesting date three years after the effective grant date. For the 2019 and 2020 awards, the Board amended the terms of the WEP to allow for 75% vesting of the ERs three years after the effective grant date and the remaining 25% of ERs five years after the effective grant date.

ERs lapse if an employee is terminated with cause or resigns prior to the vesting.

Supplementary Woodside Equity Plan ("SWEP")

The Woodside Board approved the establishment of the SWEP to enable the offering of targeted retention awards of equity rights for key capability. The SWEP was designed to be offered to a small number of employees identified as being retention critical. The SWEP awards have service conditions and no performance conditions. Each equity right entitles the participant to receive a Woodside Share on the vesting date three years after the effective grant date.

Equity rights under both the WEP and the SWEP may vest prior to the vesting date on a change of control or on a pro rata basis, in the discretion of the CEO, limited to the following circumstances; redundancy, retirement (after six months' participation), death, termination due to illness or incapacity or total and permanent disablement of a participating employee. An employee whose employment is terminated by resignation or for cause prior to the vesting date will forfeit all of their equity rights.

15 Superannuation Arrangements

All employees of the Woodside Group are entitled to benefits on retirement, disability or death from the Woodside Group's superannuation plan. The majority of employees are party to a defined contribution scheme and receive fixed contributions from Woodside Group companies and the Woodside Group's legal or constructive obligation is limited to these contributions. Contributions to defined contribution funds are recognised as an expense as they become payable. Prepaid contributions are recognised as an asset to the extent that a cash refund or a reduction in the future payment is available. The Woodside Group also operates a defined benefit superannuation scheme, the membership of which is now closed. The total amount set aside or accrued by Woodside to provide pension, retirement or similar benefits for the Directors and Senior Executives for the year ended 31 December 2021 was US$33 million. The net defined benefit plan asset at 31 December 2020 was US$19 million.

16 Insurance

Woodside has paid a premium under a contract insuring each Woodside Director, officer, secretary and employee who is concerned with the management of Woodside or its subsidiaries against liability incurred in that capacity. Disclosure of the nature of the liability covered by and the amount of the premium payable for such insurance is subject to a confidentiality clause under the contract of insurance.

17 Material Contracts

The following is a summary of contracts (not being entered into in the ordinary course of business) which have been entered into by the Woodside Group or BHP Petroleum: (i) within the two years immediately preceding the date of this Prospectus and are, or may be material; or (ii) which contain any provision under which the Woodside Group has any obligation or entitlement which is material to the Woodside Group or BHP Petroleum at the date of this Prospectus:

17.1 Woodside Group

Share Sale Agreement

Please refer to paragraph 14 of Part 10 *(Summary of the Merger)* of this Prospectus for further information regarding the Share Sale Agreement.

Deed Poll

Please refer to paragraph 1 of Part 19 *(Depositary Interests)* of this Prospectus for further information regarding the Deed Poll.

CSN Agreement

Please refer to paragraph 1 of Part 19 *(Depositary Interests)* of this Prospectus for further information regarding the CSN Agreement.

UK Depositary Agreement

Please refer to paragraph 1 of Part 19 *(Depositary Interests)* of this Prospectus for further information regarding the UK Depositary Agreement.

Integration and Transition Services Agreement

Simultaneously with the execution of the Share Sale Agreement, Woodside and BHP entered into the Integration and Transition Services Agreement ("**ITSA**") which provides for the terms under which:

- BHP will undertake certain activities to separate BHP Petroleum from BHP prior to Implementation;
- Woodside and BHP will undertake activities in preparation on and from the date of signing the ITSA until Implementation, for integration of BHP Petroleum into Woodside to form the Merged Group; and
- BHP will provide certain transition services to the Merged Group following Implementation.

The term of the ITSA shall cease upon the earlier of (i) expiration of the transition period (including any extension) for the transition service with the longest transition period, (ii) completion of the separation of the BHP Petroleum systems from BHP, or (iii) termination of the ITSA in accordance with the early termination provisions of the ITSA (provided, in any case, that the term will not continue beyond 12 months post Implementation). The early termination provisions permit termination of the ITSA: (x) by the non-defaulting party (subject to a cure period) in the event of a default with respect to a material condition (which includes obligations with respect to a material condition (which includes obligations with respect to confidential information and intellectual property rights as well as Woodside's obligations to pay termination service fees) or (y) automatically in the event of termination of the Share Sale Agreement.

The objective of the activities under the ITSA is to, among other things, seek to ensure uninterrupted operations and minimise disruptions of the parties involved, maximise certainty as to operating methodologies in the Merged Group and seek to identify opportunities to improve efficiency and reduce costs of the Merged Group (as compared to the separate cost structures of BHP Petroleum and Woodside prior to Implementation).

BHP is responsible under the ITSA for all activities which are necessary to separate BHP Petroleum from the BHP systems, processes and structures. BHP must use its reasonable endeavours to complete these activities prior to Implementation and complete any carry-over separation activities following Implementation. The ITSA contains a reporting process for monitoring the progress of those separation activities and managing any delays. A specific regime applies in respect of the activities required to separate the systems and data of BHP Petroleum from BHP systems and data, and integrate such systems and data with Woodside systems and data. All costs associated with separation activities shall be borne by BHP (including for any carry-over separation activities), except for costs associated with certain systems and data separation which shall be shared equally by the parties up to US$150 million, following which such costs shall be borne by BHP without contribution by Woodside.

Activities which are required to integrate BHP Petroleum into Woodside Group on Implementation will be developed, coordinated and undertaken by a team comprised of both Woodside and BHP personnel in accordance with an agreed upon plan and budget.

Transition services must be developed, scoped and budgeted by the parties as part of the ITSA process. The transition services will then be provided by BHP to the Merged Group following Implementation in consideration for the fees payable by Woodside to be agreed upon by the parties in respect of each category of transition service, taking into account, among other things, the prevailing rates of the current BHP services arrangements and on a cost pass through basis for services performed by third party contractors. The service term for each transition service must be agreed upon by the parties and extended as may be required and agreed, provided that no transition service shall be performed beyond 12 months post Implementation.

Scarborough Put Option Deed

On 17 August 2021, Woodside Energy Ltd, Woodside Energy Scarborough Pty Ltd ("**WES**") and certain subsidiaries of BHP entered into a 'Put Option Deed' relating to the Scarborough, Jupiter and Thebe Projects ("**Scarborough Put Option Deed**"). Woodside is operator of all three projects. WES is the majority stakeholder of the Scarborough project, with a 73.5% interest, with BHP Petroleum (Australia) Pty Ltd ("**BHP (Australia)**") holding the remaining 26.5% interest. WES and BHP (Australia) each hold a 50% interest in the Jupiter and Thebe Projects.

Specific terms of the Scarborough Put Option Deed are as follows:

- Woodside grants to BHP an irrevocable option to sell its interests in the Scarborough, Jupiter and Thebe Projects, including interests in certain key contracts and petroleum titles, to Woodside.
- If BHP exercises the option, BHP (Australia) must sell its interest in the Scarborough, Jupiter and Thebe Projects to Woodside in accordance with the terms of the Sale and Purchase Agreement attached to the Scarborough Put Option Deed.
- The option can only be exercised by BHP after 1 July 2022 and prior to 31 December 2022 and lapses if it is not exercised during this period.

Indenture

On 3 November 2003, Woodside, Woodside Finance Limited (the "**Issuer**"), Woodside Energy Ltd and the Bank of New York (the "**Trustee**") entered into an indenture ("**Indenture**") pursuant to which the Issuer may issue unsecured debentures, notes or other securities ("**Securities**").

In accordance with the Indenture, the Issuer can issue an unlimited principal amount of Securities in one or more series by providing an officer's certificate which includes the specific terms of the Securities to be issued, including but not limited to details of the principal amount of the Securities, the interest to be paid in respect of the Securities, the maturity date of the Securities and any redemption price applicable to the Securities.

Any Securities issued in accordance with the Indenture will, subject to the terms set out in any relevant officer's certificate, be redeemable at the election of:

- the Issuer, by giving at least 60 days' notice to the Trustee; or
- the Trustee, by giving no less than 30 days' notice by the Trustee.

Pursuant to the Indenture, Woodside and certain of its subsidiaries are restricted from incurring, issuing, assuming or guaranteeing any indebtedness which is secured by a mortgage, security interest or other encumbrance, subject to certain requirements and exceptions. The Indenture also specifies typical events of default, including any failure to comply with payment or other obligations specified in the Indenture or an insolvency event occurring in respect of Woodside, the Issuer or Woodside Energy Ltd.

Both Woodside and Woodside Energy Ltd are parties to the Indenture as 'Guarantors'. Each of the Guarantors guarantee, in favour of the Trustee and the holders of the Securities, the due and punctual payment of all amounts in connection with issued Securities as well as other amounts payable by the Issuer in accordance with the terms of the Indenture.

The Indenture, the Securities and the guarantee provided by the Guarantors are all governed by the laws of the State of New York, other than in respect of matters regarding the authorisation and execution of those documents by the Issuer or the Guarantors, which are governed by the laws of the State of Victoria, Australia.

Details of the Securities currently in issue are set out in paragraph 25 of Part 7 *(Overview of Woodside)* of this Prospectus under the heading "Unsecured bonds".

17.2 BHP Petroleum

Share Sale Agreement

Please refer to paragraph 14 of Part 10 *(Summary of the Merger)* of this Prospectus for further information regarding the Share Sale Agreement.

Integration and Transition Services Agreement

Please refer to paragraph 17.1 of this Part 21 (*Additional Information*) for further information regarding the Integration and Transition Services Agreement.

Scarborough Put Option Deed

Please refer to paragraph 17.1 of this Part 21 (*Additional Information*) for further information regarding the Scarborough Put Option Deed.

Shenzi Membership Interest Purchase and Sale Agreement

On 5 October 2020, BHP and Hess entered into a Membership Interest Purchase and Sale Agreement, pursuant to which BHP agreed to acquire an additional 28% working interest in the Shenzi field in the deepwater U.S. GOM for a total consideration of US$505 million, subject to customary adjustments. BHP is the operator of the Shenzi field and the transaction increased its working interest from 44% to 72%, with Repsol holding the remaining 28% working interest.

The transaction completed on 6 November 2020, with an effective date of 1 July 2020.

Neptune Purchase and Sale Agreement

On 6 April 2021, BHP Billiton Petroleum (Deepwater) Inc., BHP Billiton Petroleum (GOM) Inc. and EnVen entered into a Purchase and Sale Agreement, pursuant to which EnVen agreed to acquire BHP's entire 35% ownership interest and operatorship of the Neptune field in the deepwater GOM. The transaction increased EnVen's ownership interest in the Neptune field from 30% to 65%.

The transaction completed on 20 May 2021, with an effective date of 1 July 2020.

18 Licences and Leases

The table below lists the exploration titles expected to be held by the Merged Group as at the Implementation Date. Following the Implementation Date, the Merged Group will continue to assess the titles and licences it holds in line with its strategy. Note this table does not include licences associated with the producing and growth projects previously disclosed in Part 7 *(Overview of Woodside)* and Part 8 *(Overview of BHP Petroleum)* of this Prospectus where exploration activities may also be undertaken.

Location	Titles and Licences	Titles and Licences	Titles and Licences
Australia	WA-356-P	WA-404-P	WA-550-P
	WA-526-P	WA-28-P	
	NT/P86	WA-536-P	
Barbados	Bimshire	Carlisle Bay	
Canada – Newfoundland-Labrador	EL 1157	EL 1158	
Congo – Deep-water	Marine XX		
Egypt – Red Sea	Block 1	Block 3 (pending Gov approval)	Block 4 (pending Gov approval)
Ireland – Porcupine Basin	FEL 5/13		
Myanmar – Deep-water Bay of Bengal[1]	AD-1	AD-7	AD-8
	A-7		
Senegal – Deep-water	Rufisque Offshore	Sangomar Offshore	Sangomar Offshore Deep
South Korea – Deep-water	Block 6-1N	Block 8	
T&T	TTDAA 5		

(1) On 27 January 2022, Woodside decided to withdraw from its interests in Myanmar. Woodside has commenced arrangements to formally exit all Blocks in which it participates in Myanmar including AD-7, A-7, AD-1, AD-8 and A-6.

Location	Titles and Licences	Titles and Licences	Titles and Licences
United States – Alaminos Canyon	AC 034	AC 079	AC 125
	AC 035	AC 080	AC 126
	AC 036	AC 081	AC 127
	AC 039	AC 082	AC 170
	AC 078	AC 083	
United States – Desoto Canyon	DC 579	DC 802	DC 803
	DC 667		
United State – East Breaks	EB 655	EB 742	EB 871
	EB 656	EB 785	EB 872
	EB 699	EB 786	EB 914
	EB 700	EB 830	EB 915
	EB 701	EB 870	
United States – Garden Banks	GB 574	GB 677	GB 805
	GB 575	GB 716	GB 806
	GB 619	GB 721	GB 851
	GB 630	GB 760	GB 852
	GB 672	GB 762	GB 895
	GB 676	GB 772	
United States – Green canyon	GC 080	GC 123	GC 124
	GC 168	GC 237-BOTTOM	GC 238-BOTTOM
	GC 282-BOTTOM	GC 564	GC 608-MIDDLE
	GC 679[2]	GC 738	GC 768-MIDDLE
	GC 870		
United States – Mississippi Canyon	MC 368	MC 412	MC 798
	MC 369	MC 455	MC 842
	MC 411	MC 456	

(2) BHP Petroleum owns all of block GC 679 from 16,048' to 99,999' (deep rights).

19 Statutory Auditors

The auditors of Woodside for the financial years ended on 31 December 2019, 31 December 2020 and 31 December 2021 have been Ernst & Young, whose registered address is at 11 Mounts Bay Road, Perth, WA 6000. Ernst & Young is registered to carry out audit work by ASIC and has no material interest in the Company.

Ernst & Young have audited the annual consolidated financial statements for Woodside, which have been prepared in accordance with Australian Accounting Standards and comply with International Reporting Standards as issued by the International Accounting Standards Board.

On 14 October 2021, the Woodside Board selected PricewaterhouseCoopers to be the Company's auditor from the 2022 fiscal year. Such selection and change in auditor was adopted at the proposal of the Audit and Risk Committee following a competitive tender process. This selection must be approved by Woodside Shareholders at the Woodside Shareholders' Meeting to be held on 19 May 2022. Accordingly, Ernst & Young, will retire as Company's auditor subject to regulatory approval from ASIC.

20 Working Capital

Woodside is of the opinion that the working capital available to the Group is sufficient for the Group's present requirements, that is, for at least the next 12 months following the date of this Prospectus.

21 No Significant change

Woodside Group

The financial performance of the Woodside Group has benefited from increases in commodity prices since 31 December 2021. There has been no other significant change in the financial performance or financial position of the Woodside Group since 31 December 2021, being the end of the last financial period of the Woodside Group for which audited consolidated financial statements have been published, to the date of this Prospectus.

BHP Petroleum

The financial performance of BHP Petroleum has benefited from increases in commodity prices since 31 December 2021. There has been no other significant change in the financial performance or financial position of BHP Petroleum since 31 December 2021, being the end of the last financial period of BHP Petroleum for which interim financial statements have been published, to the date of this Prospectus.

22 The Competent Person's Report

Woodside confirms that no material changes have occurred since the effective date of the Competent Person's Report, being 31 December 2021, the omission of which would make the Competent Person's Report misleading.

23 Related Party Transactions

All transactions with related parties are conducted on an arms' length term basis in accordance with normal business terms. Transactions between related parties that are Woodside subsidiaries are eliminated on consolidation. Details of contractual arrangements to give effect to the Merger are described in Part 10 *(Summary of the Merger)* of this Prospectus. Related party matters, including joint ventures, associates, joint operations and transactions with Senior Executives of Woodside can be found in note E.2, E3 and E.6 to the Woodside Historical Financial Information.

Save as disclosed in Part 15 (*Unaudited Pro Forma Financial Information*) of this Prospectus there were no related party transactions between Woodside and BHP Petroleum Group Members that were entered into during the financial years ended 31 December 2021, 2020 and 2019.

24 Legal Proceedings

Woodside Group

The Woodside Group is involved from time to time in legal proceedings and governmental investigations of a character normally incidental to its businesses, including claims and pending actions against the Woodside Group seeking damages, or clarification or prosecution of legal rights and regulatory inquiries regarding business practices. Insurance or other indemnification protection may offset the financial impact of any successful claim.

Save as disclosed below, there are no governmental, legal or arbitral proceedings (including any such proceedings which are pending or threatened and of which Woodside is aware) which may have, or have had, during the 12 months prior to the date of this Prospectus, a significant effect on Woodside's financial position or profitability.

Woodside notes the following litigation matters:

- In March 2016, Armada Balnaves Pte Ltd ("**AB**") commenced proceedings in the Supreme Court of Western Australia against Woodside claiming damages (up to US$184.6m Woodside share) in respect of Woodside's termination of AB's contract. In January 2020, the Court dismissed AB's action. AB appealed, and the appeal was heard in July 2021, and judgement is currently reserved.
- In December 2020, the Conservation Council of Western Australia filed applications seeking judicial review of decisions in respect of approvals under section 45C of the Environmental Protection Act (WA) granted for each of the North West Shelf and Pluto Gas Plant. Each approval was granted in July 2019. The Supreme Court of Western Australia dismissed the proceedings in March 2022.
- In November 2021 Woodside was served with a further proceeding commenced by the Conservation Council of Western Australia in the Supreme Court of Western Australia seeking judicial review of a decision by the CEO of the Western Australian Department of Water and Environmental Regulation to grant Woodside a works approval for the Pluto Train 2 project granted in May 2021.

BHP Petroleum

BHP Petroleum is also involved from time to time in legal proceedings and governmental investigations of a character normally incidental to its business, on the basis described above in relation to the Woodside Group.

There are no governmental, legal or arbitral proceedings (including any such proceedings which are pending or threatened and of which BHP Petroleum is aware) which may have, or have had, during the 12 months prior to the date of this Prospectus, a significant effect on BHP Petroleum's financial position or profitability.

25 Consents

The following persons have given, and have not, before the date of issue of this Prospectus, withdrawn their consent to be named in this Prospectus in the form and context in which they are named:

- Morgan Stanley as Woodside's financial adviser;
- King & Wood Mallesons as Woodside's Australian and English legal adviser;
- Gaffney Cline & Associates Limited as the Competent Person;
- Computershare Investor Services PLC as Woodside's UK Depositary;
- Computershare Investor Services Pty Limited as Woodside Share Registry; and
- Wood Mackenzie who has provided Woodside with expert industry information.

For the purpose of Rule 5.3.9R of the Prospectus Regulation Rules, the Competent Person has authorised the contents of such parts of this Prospectus that comprise the Competent Person's Report.

Ernst & Young has given and has not withdrawn its written consent to the inclusion in this Prospectus of its report as set out in Section B of Part 15 (*Unaudited Pro Forma Financial Information*) and has authorised the contents of this report as part of this document for the purposes of UK Prospectus Regulation Rule 5.3.2R(2)(f) and item 1.3 of Annex 1 of the UK Prospectus Delegated Regulation.

Morgan Stanley (in its capacity as financial adviser to the Company) has given and not withdrawn its written consent to the inclusion in this Prospectus of its name in the form and context in which it is included and has authorised the contents of such parts of this Prospectus.

Wood Mackenzie has given and not withdrawn its written consent to the inclusion in this Prospectus of its name in the form and context in which it is included and has authorised the contents of such parts of this Prospectus.

Other than as specifically outlined above, each party referred to in this paragraph 25 has not caused or authorised the issue of this Prospectus and does not make or purport to make any statement in this Prospectus or any statement on which a statement in this Prospectus is based and takes no responsibility for any part of this Prospectus other than any reference to its name. None of the parties referred to in this paragraph has a material interest in Woodside.

26 Rights of Holders Through CREST

Please refer to Part 19 *(Depositary Interests)* of this Prospectus for further information regarding CREST.

27 Miscellaneous

Estimated transaction costs in connection with the Merger are US$410 million (excluding integration costs).

Woodside confirms that all third-party information contained in this Prospectus has been accurately reproduced and, so far as Woodside is aware and is able to ascertain from information published by such third parties, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where third party information has been used in this Prospectus, the source of such information has also been identified. While industry surveys, publications, consultant surveys and forecasts generally state that the information contained therein has been obtained from sources believed to be reliable, the accuracy and completeness of such information is not guaranteed. Woodside has not independently verified any of the data from third party sources, nor has Woodside ascertained the underlying economic assumptions relied upon therein. Similarly, internal surveys, industry forecasts and market research, which Woodside believes to be reliable based upon the Directors' knowledge of the industry, have not been independently verified. Statements as to Woodside's market position are based on recently available data.

28 Documents available for inspection

Copies of the following documents may be inspected at the offices of KWM Europe LLP during normal business hours on any Business Day in England as well as via Woodside's website (https://www.woodside.com.au/) for the 12 months following the date of this Prospectus:

- the Certificate of Incorporation;
- the Woodside Constitution;
- the Competent Person's Report;
- the annual consolidated financial statements of the Woodside Group for the financial years ended 31 December 2021, 31 December 2020 and 31 December 2019;
- the financial statements in respect of BHP Petroleum for (i) the half year ended 31 December 2021 (together with the half year ended 31 December 2020 for comparatives purposes) and, (ii) the financial years ended 30 June 2021, 30 June 2020 and 30 June 2019; and
- this Prospectus.

Copies of the following documents may be inspected at the offices of KWM Europe LLP during normal business hours on any Business Day in England for the 12 months following the date of this Prospectus:

- Commodity Report, Global Gas Demand dated October 2021 by Wood Mackenzie; and
- Macro Oils, Long-term 2021 Outlook to 2050 Report dated November 2021 by Wood Mackenzie.

Inspection of the above documents in person may only take place in accordance with any prevailing measures at the time in connection with the COVID-19 pandemic.

AASB	Australia Accounting Standards Board
ACCC	Australian Competition and Consumer Commission
Additional Share Consideration	a number of Woodside Shares calculated in accordance with the Share Sale Agreement as being a notional entitlement to DRP Shares issued after the Effective Time
Admission	the admission of all of the Woodside Shares to the standard segment of the Official List and to trading on the Main Market for listed securities
ADSs or American Depositary Shares or American Depositary	American depositary shares
Algerian Assets	the assets comprising BHP Petroleum's effective 28.85% interest in the Rhourde Ouled Djemma Integrated Development
ASIC	Australian Securities and Investments Commission
ASX	ASX Limited or the securities exchange that it operates, as the context requires
ASX Listing Rules	the listing rules of the ASX
ASX Recommendations	the ASX Corporate Governance Council's Corporate Governance Principles and Recommendations (4th Edition)
ATO	Australian Taxation Office
BHP	BHP Group Limited, ACN 004 028 077 which, prior to Implementation, is the ultimate parent company of BHP Petroleum
BHP ADS Holders	Eligible BHP Shareholders holding BHP ADSs on the Distribution Record Date
BHP ADSs	American Depositary Shares representing BHP Shares; each BHP ADS represents two BHP Shares
BHP Board	the directors of BHP from time to time acting as a board
BHP Competing Proposal	a proposal which, if entered into or completed, would result in one or more parties other than Woodside directly or indirectly acquiring shares in BHP Petroleum or a substantial part of its business or assets (or would result in a similar outcome), or which would require BHP to abandon or not proceed with the Merger
BHP CSN	the facility arranged by BHP to enable certain investors to hold their interest in BHP ordinary shares in a form which will enable them to trade those shares on the LSE
BHP Group	BHP and its direct and indirect subsidiaries from time to time
BHP Group Member	a member of the BHP Group
BHP Information	the information contained in: (a) paragraph B2 of Part 1 (*Summary*) under the headings "*BHP Petroleum Historical Financial Information*" and "*Changes since end of last financial period — BHP Petroleum*";

(b) the following statement in paragraph 1.2a of Part 2 (*Risk Factors*): "which for the year ended 31 December 2021, was approximately 63% natural gas, comprising LNG, LPG and pipeline gas, and 37% oil and condensate (excluding Algeria and Neptune production)";

(c) Part 3 (*Presentation of Financial and Other Information*) under the heading "*BHP Petroleum non-IFRS financial measures*";

(d) Part 8 (*Overview of BHP Petroleum*);

(e) paragraph 1 of Part 9 *(Industry Overview)* under the heading "*BHP Petroleum Overview*";

(f) paragraph 3 of Part 10 (*Summary of the Merger*) under the heading "*BHP and BHP Petroleum"* and paragraph 4 of Part 10 (*Summary of the Merger*) under the heading "*BHP rationale*";

(g) paragraph 4 of Part 10 (*Summary of the Merger*) under the heading "*Greater scale and diversity of geographies, products and end markets through an attractive and long-life conventional gas and high-margin oil portfolio*" to the extent that the combined production and reserves information of the Merged Group is derived from information relating to BHP Petroleum;

(h) the following statement in paragraph 13 of Part 10 (*Summary of the Merger*): "BHP intends to fully frank the Special Dividend and, accordingly the Special Dividend will have accompanying franking credits.";

(i) the tables "The Merged Group's Net Reserves as at 31 December 2021" and "The Merged Group's Net Contingent Resources as at 31 December 2021" in paragraph 3 of Part 11 (Overview of the Merged Group) to the extent that the rows include information for interests in projects held by BHP Petroleum only, and then only to the extent that such information relies on, or is derived from, information prepared or provided by BHP;

(j) paragraph 5.2 of Part 11 (*Overview of the Merged Group*);

(k) Part 14 (*Historical Financial Information of the Merged Group*) under the heading "*BHP Petroleum Historical Financial Information*";

(l) Part 15 (*Unaudited Pro Forma Financial Information*) contained in:

   (i) the column titled "BHP Petroleum Income Statement 30 June 2021 US$m" in the table set out in Note 2 (*BHP Petroleum*) to the Unaudited Pro Forma Income Statement For The Year Ended 31 December 2021; and

   (ii) the column titled "BHP Petroleum Statement of Net Assets 31 December 2021 US$m" in the table set out in Note 2 (*BHP Petroleum*) to the Unaudited Pro Forma Statement of Net Assets As At 31 December 2021;

(m) Part 18 (*Operating and Financial Review of BHP Petroleum*);

(n) the following statements contained in paragraph 2 of Part 20 (*Taxation*):

   (i) "BHP intends to distribute the New Woodside Shares to Eligible BHP Shareholders by way of an in-specie dividend (Special Dividend)".

   (ii) "The Merger is not expected to qualify for demerger tax rollover relief in relation to the Special Dividend. BHP intends to fully frank the Special Dividend. Although the quantum of the Special Dividend will not be known until the date of distribution it will be based on the market value of New Woodside Shares at that time".

   (iii) "BHP has applied to the Commissioner of Taxation (Commissioner) for a class ruling confirming certain income tax implications of Implementation for Australian resident Eligible BHP Shareholders.

	The final class ruling will be published by the Commissioner shortly after the Implementation”. (iv) “The class ruling application is principally concerned with (i) confirming that demerger tax rollover relief will not be available to Eligible BHP Shareholders and (ii) confirming the Australian income tax consequences of the Special Dividend for Eligible BHP Shareholders”. (v) “BHP intends to fully frank the Special Dividend and, accordingly, the Special Dividend will have accompanying franking credits.”;’ (vi) “BHP intends to fully frank the Special Dividend.”; and (vii) “Further information will be provided by BHP to assist you in determining the amount of your Special Dividend and cost base for each New Woodside Share as soon as practical following Implementation.”; (o) the following statements contained in paragraph 3 of Part 20 (*Taxation*): (i) “However, BHP does not calculate earnings and profits in accordance with U.S. federal income tax principles. Accordingly, U.S. Holders should expect to treat the entire amount of the Special Dividend as a taxable dividend for U.S. federal income tax purposes.”; (ii) “The BHP ADSs are listed on the NYSE”; and (iii) “BHP believes that the BHP Securities will not be stock of a PFIC for U.S. federal income tax purposes, but this conclusion is based on a factual determination made annually and thus is subject to change.”; (p) Part 21 (*Additional Information*) contained in: (i) paragraph 1 under the heading “*BHP*”; (ii) paragraph 17.2; (iii) paragraph 21 under the heading “*BHP Petroleum*”; and (iv) paragraph 24 under the heading “*BHP Petroleum*”; (q) the exploration titles held by BHP Petroleum contained in paragraph 18 of Part 21 (*Additional* Information); and (r) Annexure 2 (BHP Petroleum Historical Financial Information).
BHP Petroleum	BHP Petroleum International Pty Ltd (with registration number 006 923 897) and, unless context otherwise requires, its subsidiaries, presented on a post-Restructure basis and excludes the Restructure Entities. References to “BHP Petroleum International Pty Ltd” are to “BHP Petroleum International Pty Ltd” excluding its subsidiaries
BHP Petroleum Group Member	a reference to ‘BHP Petroleum Group Member’ or a ‘member of BHP Petroleum’ is to BHP Petroleum or any of its Subsidiaries on a post-Restructure basis
BHP Petroleum Historical Financial Information	the financial statements in respect of BHP Petroleum for (i) the half year ended 31 December 2021 (together with the half year ended 31 December 2020 for comparatives purposes) (unaudited), (ii) the financial years ended 30 June 2021 and 30 June 2020 (audited) and (iii) the financial year ended 30 June 2019 (unaudited) as referred to in Part 14 (Historical Financial Information of the Merged Group of this Prospectus and appended at Annexure 2 of Part 24 of this Prospectus
BHP Shares	fully paid ordinary shares in the capital of BHP, including shares held by the custodian in respect of which BHP ADSs have been issued

BHP Shareholders	a holder of BHP Shares
Board	the Directors acting as a board
Browse	the Browse Project located in the offshore Browse Basin, approximately 425 km north of Broome in Western Australia, comprising the Brecknock, Calliance and Torosa fields
Business Day in England	a day other than a Saturday, Sunday or public holiday in England when banks in London are open for business
Certificate of Incorporation	the certificate of incorporation of the Company, as amended and restated from time to time
CFIUS	the Committee on Foreign Investment in the United States
CGT	capital gains tax
Chair or Chair of the Woodside Board	the Chair of the Woodside Board from time to time
Chaoyang	Chaoyang Petroleum (Trinidad) Block 2C Limited
Chevron	Chevron Corporation and / or any one or more of its subsidiaries, as the context requires
CNOOC	CNOOC Limited and / or any one or more of its subsidiaries, as the context requires
Completion Payment	the Woodside Dividend Payment, plus or minus the Locked Box Payment (as appropriate) and any other adjustments in accordance with the Share Sale Agreement
Competent Person	Gaffney Cline & Associates Limited
Computershare UK	the operator of the CSN Facility being Computershare Investor Services PLC
Conditions	the conditions precedent to Implementation as set out in the Share Sale Agreement and as detailed in paragraph 6 of Part 10 *(Summary of the Merger)* of this Prospectus
Corporations Act	Corporations Act 2001 (Cth)
CPR or Competent Persons Report	the Competent Persons Report produced by the Competent Person as appended at Annexure 3 of Part 24 *(Competent Persons Report)* of this Prospectus
CREST	the relevant system in respect of which Euroclear UK & International Limited is the operator (as defined in the CREST Regulations)
CREST Regulations	the Uncertificated Securities Regulations 2001 (SI 2001 No. 3755), as amended
CSN	Corporate Sponsored Nominee
CSN Agreement	the agreement in relation to nominee service between Computershare UK and Woodside, summarised in Part 19 *(Depositary Interests)* of this Prospectus pursuant to which Computershare UK will provide the CSN Facility to CSN Participants
CSN Facility	the facility arranged by Woodside with Computershare UK to enable certain Shareholders to receive their interests in Woodside Shares in a form which will enable them to trade those shares and admit the shares to trading on the LSE, as described in paragraph 1 of Part 19 *(Depositary Interests)* of this Prospectus

CSN Participant	a participant in the CSN Facility
CSN Restricted Jurisdictions	the jurisdictions not detailed as permitted countries in the CSN Terms and Conditions, in which participation in the CSN Facility is not permitted
CSN Terms and Conditions	the terms and conditions under which Computershare UK provides the CSN Facility, as amended from time to time, which are summarised in Part 19 *(Depositary Interests)* of this Prospectus, a copy of which is made available on Woodside's website at www.woodside.com.au
Custodian	Computershare Clearing Pty Limited (ABN 16 063 826 228) or a subsidiary or third party appointed by the UK Depositary to provide the custody services
Dated Brent	pricing marker for physical cargo of North Sea Brent light crude oil, which has been allocated a specific forward-loading date.
Deed Poll	the deed poll executed by the UK Depositary in favour of the holders of the Depositary Interests from time to time
Depositary Interests	the dematerialised depositary interests issued by the UK Depositary in respect of the underlying Woodside Shares
Depositary Interest Holders	Holders of the Depositary Interests through CREST
Directors or Woodside Directors	the directors of Woodside from time to time, who, as at the date of this Prospectus, are those set out in paragraph 12 of Part 7 *(Overview of Woodside)* and who, as at the Implementation Date, are expected to be those set out in Part 12 (*Directors, Senior Executives and Corporate Governance)* of this Prospectus
Distribution Record Date	the time determined by the BHP Board as the date for determining BHP Shareholders' entitlement to the distribution of the Share Consideration
DRP Shares	Woodside Shares issued to Woodside Shareholders on account of their participation in the dividend reinvestment plan conducted by Woodside
DTR or Disclosure Guidance and Transparency Rules	the disclosure guidance and transparency rules made by the FCA under section 73A of FSMA, as amended
Effective Time	11:59 p.m. (Melbourne time) on 30 June 2021, being the effective time of the Merger
EIP	the Executive Incentive Plan
EIS	the Executive Incentive Scheme
Eligible BHP Shareholder	a BHP Shareholder whose address is shown in the BHP Register (as determined by BHP) on the Distribution Record Date as being in one of the following jurisdictions: • Australia, Canada, Chile, France, Germany, Ireland, Italy, Japan, Jersey, Luxembourg, Malaysia, New Zealand, Netherlands, Norway, Singapore, Spain, Sweden, Switzerland, United Arab Emirates, the United Kingdom and the United States; and • any other jurisdiction in respect of which BHP determines (acting reasonably and following consultation with Woodside) that it is not prohibited or unduly onerous or impractical to transfer or distribute New Woodside Shares to the BHP Shareholders in those jurisdictions And certain South African BHP Shareholders who validly elect to receive New Woodside Shares in accordance with arrangements to be outlined by BHP

Employees	the employees of Woodside from time to time
EnVen	EnVen Energy Ventures, LLC
Equity Award Rules	the rules approved by the Woodside Board in February 2018 that govern offers of incentive securities to eligible employees
ESG	environmental, social and governance
Exchange Act	the U.S. Securities Exchange Act of 1934, as amended
Executive Committee	Woodside's executive committee (including the Executive Directors) whose members, as at the date of this Prospectus, are those set out in paragraph 12 of Part 7 *(Overview of Woodside)* and, whose members, as at the Implementation Date, are expected to be those set out in Part 12 (*Directors, Senior Executives and Corporate Governance)* of this Prospectus.
Existing Woodside Shareholders	Woodside Shareholders immediately prior to Implementation
Existing Woodside Shares	the Woodside Shares on issue immediately prior to Implementation
ExxonMobil	Exxon Mobil Corporation and / or any one or more of its subsidiaries, as the context requires
FAR	Fixed Annual Reward
FATA	the Foreign Acquisitions and Takeovers Act 1975 (Cth)
FCA	the Financial Conduct Authority
FIRB	Foreign Investment Review Board
FSMA	the Financial Services and Markets Act 2000, as amended
FY	(a) with respect to BHP Petroleum, its financial year ended 30 June; and (b) with respect to Woodside, its financial year ended 31 December
GIP	Global Infrastructure Partners
Greater Sunrise	the Greater Sunrise Project, which comprises the Sunrise and Troubadour gas and condensate fields, collectively known as Greater Sunrise, located between Australia and Timor- Leste
GST	Goods and services tax
Hess	Hess Corporation and / or any one or more of its subsidiaries, as the context requires
Historical Financial Information	the historical financial information of Woodside and the historical financial information of BHP Petroleum, being the financial statements and the accompanying notes contained in this Prospectus, as referred to in Part 14 *(Historical Financial Information)* of this Prospectus
Historical Financial Information Period	the period covered by the Woodside Historical Financial Information
HMRC	Her Majesty's Revenue and Customs
HSR Act	the Hart–Scott–Rodino Antitrust Improvements Act of 1976, as amended

IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
Implementation	completion of the Merger pursuant to the Share Sale Agreement
Implementation Date	the date on which Implementation occurs
Independent Expert	KPMG, being the independent expert appointed by Woodside
Independent Expert's Report	the report issued by the Independent Expert assessing the fairness of the Merger to Woodside Shareholders, including the Independent Technical Specialist Report completed by Gaffney Cline & Associates Limited annexed thereto
Independent Technical Specialist Report	the report issued by the Independent Technical Expert and annexed to the Independent Expert's Report
Ineligible Foreign BHP Shareholders	BHP Shareholders who are not Eligible BHP Shareholders
Inpex	Inpex Corporation and / or any one or more of its subsidiaries, as the context requires
IRS	the U. S. Internal Revenue Service
ISIN	International Securities Identification Number
ITSA or Integration and Transition Services Agreement	the Integration and Transition Services Agreement between BHP and Woodside dated 22 November 2021
JKM	Japan Korea Marker
Key Management Personnel	those Senior Executives that are relevant in establishing that the Company has appropriate expertise and experience for the management of the Company's business
KPI	key performance indicator
KPMG	KPMG Financial Advisory Services (Australia) Pty Ltd
KUFPEC	Kuwait Foreign Petroleum Exploration Company K.S.C. and/ or any one or more of its subsidiaries, as the context requires
Last Practicable Date	24 March 2022, being the last practicable date before the date of this Prospectus
LEI	Legal Entity Identifier
Locked Box Payment	has the meaning given in the Share Sale Agreement, being in general terms the net cash flow of BHP Petroleum (subject to various adjustments) as calculated in accordance with the Share Sale Agreement
London Stock Exchange or LSE	London Stock Exchange plc, a public limited company incorporated in England & Wales with company number 02075721 and having its registered office at 10 Paternoster Square, London EC4M 7LS
LSE Listing Rules	the listing rules made by the FCA under section 73A of FSMA
Main Market	the Main Market for listed securities of the London Stock Exchange
MAR	the European Union Market Abuse Regulation (596/2014) as it forms part of domestic law by virtue of the European Union (Withdrawal) Act 2018 and as amended

Merged Group	the Group following Implementation, which will comprise Woodside and its subsidiaries (including BHP Petroleum)
Merged Group Board	the board of directors of the Merged Group
Merger	the acquisition of BHP Petroleum by a member of Woodside Group pursuant to the Share Sale Agreement
Merger Commitment Deed	the Merger Commitment Deed between Woodside and BHP dated 17 August 2021, with an effective date of 1 July 2021
Merger Consideration	the consideration payable by Woodside to BHP in respect of the Merger pursuant to the Share Sale Agreement, having the same meaning as "Purchase Price"
Merger Resolution	the ordinary resolution of Woodside Shareholders to approve the issue of the New Woodside Shares comprising the Share Consideration under the Merger for the purposes of ASX Listing Rule 7.1 and for all other purposes
MIMI	Japan Australia LNG (MIMI) Pty Ltd and / or any one or more of its subsidiaries, as the context requires
Mitsui	Mitsui E&P Australia Pty Ltd and / or any one or more of its subsidiaries, as the context requires
Morgan Stanley	Morgan Stanley & Co. International plc
National Gas Company	The National Gas Company of Trinidad and Tobago and / or any one or more of its subsidiaries, as the context requires
NEDSP	the Non-Executive Director Share Plan
New Woodside ADSs	new Woodside ADSs issued in respect of New Woodside Shares
New Woodside Shares	Woodside Shares to be issued on Implementation as Share Consideration
Non-Executive Director	a non-executive director of Woodside from time to time who, as at the date of this Prospectus, are those set out in paragraph 12 of Part 7 *(Overview of Woodside)* and who, as at the Implementation Date, are expected to be those set out in Part 12 (*Directors, Senior Executives and Corporate Governance)* of this Prospectus
North West Shelf Project	the North West Shelf project consisting of several offshore conventional gas and condensate fields in the Carnarvon Basin off the Pilbara coast of Western Australia and associated offshore and onshore infrastructure
NYSE	the New York Stock Exchange
NYSE Listing Rules	the listing rules of the NYSE
Official List	the Official List of the FCA
OPEC	the Organization of the Petroleum Exporting Countries
OPEC+	refers to the OPEC group of 13 members and 10 of the world's major non-OPEC oil-exporting nations
Performance Right	a right to receive a Woodside Share (or, at the Board's discretion, a cash equivalent). No amount is payable by the executive on the grant or vesting of a Performance Right

Permitted Equity Raise	A specified form of Woodside equity raise permitted the Share Sale Agreement, undertaken by Woodside after 17 August 2021, which may have the effect of increasing the number of Woodside Shares comprising the Share Consideration
Petrosen	Société Des Pétroles Du Sénégal and / or any one or more of its subsidiaries, as the context requires
Premium Listing	a listing on the premium segment of the Official List
PRMS	2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers (SPE)/World Petroleum Council (WPC)/American Association of Petroleum Geologists (AAPG)/Society of Petroleum Evaluation Engineers (SPEE)/Society of Exploration Geophysicists (SEG)/Society of Petrophysicists and Well Log Analysts (SPWLA)/European Association of Geoscientists and Engineers (EAGE)
Prospectus	the prospectus (together with any supplementary prospectus required to be published by Woodside pursuant to article 23 of the UK Prospectus Regulation) prepared by Woodside in accordance with the UK Prospectus Regulation Rules in connection with the Admission
Purchase Price	has the meaning given in the Share Sale Agreement, being the consideration payable by Woodside to BHP in respect of the Merger pursuant to the Share Sale Agreement (defined as the "Purchase Price" in the Share Sale Agreement) comprising: • the Share Consideration; • plus the Woodside Dividend Payment; • plus the Locked Box Payment (if payable by Woodside) or less the Locked Box Payment (if payable by BHP, in which case if the Locked Box Payment exceeds the Woodside Dividend Payment then BHP will pay Woodside the difference); as adjusted in accordance with the Share Sale Agreement.
Put Option	BHP's option to sell to Woodside its interests in the Scarborough, Jupiter and Thebe Projects on agreed terms and conditions pursuant to the Scarborough Put Option Deed.
Relevant Small Parcel BHP Shareholder	a Small Parcel BHP Shareholder who validly elects (in accordance with the instructions to be issued by BHP) to have the New Woodside Shares to which they will be entitled (pursuant to Merger and the subsequent distribution of New Woodside Shares) sold by the Sale Agent under the sale facility.
Repsol	Repsol, S.A. and / or any one or more of its subsidiaries, as the context requires
Restricted Shares	Woodside Shares that are awarded to executives as the deferred component of their short-term award or as a part of their VAR under the EIS. No amount is payable by the executive on the grant or vesting of a Restricted Share
Restructure	the transfer out of BHP Petroleum of the Restructure Entities to members of the BHP Group which do not otherwise form part of BHP Petroleum
Restructure Entities	the following entities which hold non-oil and gas and/or legacy assets and operations BHP BK Limited, BHP Billiton Petroleum Great Britain Limited, BHP Mineral Resources Inc., BHP Copper Inc., Resolution Copper Mining LLC, BHP Resolution Holdings LLC, and BHP Capital Inc
RTSR	relative total shareholder return

Sale Agent	a nominee appointed by BHP following consultation with Woodside to receive and sell New Woodside Shares comprising the Share Consideration attributable to the Ineligible Foreign BHP Shareholders and Relevant Small Parcel BHP Shareholders (if applicable)
Sangomar Oil Field Development	the greenfield Sangomar Oil Field Development Phase 1 Project offshore Senegal
Santos	Santos Limited and / or any one or more of its subsidiaries, as the context requires
SARB	South African Reserve Bank
Scarborough Put Option Deed	the 'Put Option Deed' dated 17 August 2021 between Woodside Energy Ltd, Woodside Energy Scarborough Pty Ltd and certain subsidiaries of BHP relating to the Scarborough, Jupiter and Thebe Projects
SDRT	UK stamp duty reserve tax
SEC	the U.S. Securities and Exchange Commission, an independent agency of the U.S. federal government
Securities Act	the U.S. Securities Act of 1933, as amended
Senior Executive	a member of the Executive Committee
Share Consideration	the number of New Woodside Shares to be issued as part of the Merger Consideration determined in accordance with the following formula: $A = ((48 / 52) X B) + C + D$ where: A is the number of Woodside Shares. B is the agreed number of Woodside Shares at the Effective Time, being 970,598,757. C is the Additional Share Consideration. D is the number of Woodside Shares determined in accordance with the Share Sale Agreement as compensation for the Permitted Equity Issue (taking account of the issue price discount).
Share Sale Agreement	the Share Sale Agreement between Woodside and BHP dated 22 November 2021
Shareholders or Woodside Shareholders	a holder of Woodside Shares from time to time
Shell	Shell plc and / or any one or more of its subsidiaries, as the context requires
Small Parcel BHP Shareholders	BHP Shareholders (other than an Ineligible Foreign BHP Shareholder): • who are registered on the BHP Australian principal share register and hold 1,000 BHP shares or less or on the BHP depositary interest register and hold 1,000 BHP depositary interests or less; • whose registered address in the BHP Australian principal share register or BHP depositary interests register is in any of Australia, Canada, Chile, France, Germany, Ireland, Japan, Jersey, Luxembourg, Malaysia, New Zealand, Norway, Spain, Sweden, Switzerland, the United Arab Emirates and the United Kingdom; and • who are not, and are not acting for the account or benefit of persons, in the United States

SPE PRMS	the Petroleum Resources Management System, 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, and which provides a set of standards and guidance to estimate, classify and categorise petroleum resources
Special Dividend	the special dividend by which BHP intends to distribute the New Woodside Shares to Eligible BHP Shareholders
Standard Listing	a listing on the standard segment of the Official List
Subsidiaries	the subsidiaries (both direct and indirect) of the Company from time to time, details of which are set out at Part 21 (*Additional Information*) of this Prospectus
T&T	Republic of Trinidad and Tobago
UK Depositary	Computershare Investor Services PLC in its capacity as depositary appointed for the holders of Depositary Interests
UK Depositary Agreement	the agreement entered into between the Company and the UK Depositary appointing the UK Depositary
UK Nominee	Computershare Company Nominees Limited or one of Computershare Investor Services PLC's group companies which may be nominated by it to provide the services, in its capacity as nominee in respect of the CSN Facility
UK Prospectus Delegated Regulation	Regulation (EU) 2019/980 supplementing the UK Prospectus Regulation, as it forms part of domestic law by virtue of the European Union (Withdrawal) Act 2018 and as amended
UK Prospectus Regulation	Regulation (EU) 2017/1129 of the European Parliament and Council of 14 June 2017 as it forms part of domestic law by virtue of the European Union (Withdrawal) Act 2018 and as amended
UK Prospectus Regulation Rules	the prospectus regulation rules made by the FCA under section 73A of FSMA, as amended
Unaudited Pro Forma Financial Information	the unaudited pro forma financial information of the Merged Group and the accompanying notes contained in Part 15 *(Unaudited Pro Forma Financial Information)* of this Prospectus
U.S. GOM	United States Gulf of Mexico
U.S. Holder	see "U.S. Holder Defined" in paragraph 3 of Part 20
U.S. Registration Statement	Woodside's registration statement on Form F-4 in respect of the distribution of the New Woodside Shares under U.S. securities laws
U.S. Treasury	the U.S. Department of the Treasury
VAR	Variable Annual Reward
Variable Pay Right or VPR	a right to receive a fully paid Woodside Share (or, at the Woodside Board's discretion, a cash equivalent), of a type granted under the EIP prior to 2018. No amount is payable by the executive on the grant or vesting of a Variable Pay Right
VWAP	volume weighted average price
Woodside	Woodside Petroleum Ltd (to be renamed Woodside Energy Group Ltd, subject to approval by Woodside Shareholders at the Meeting) ACN 004 898 962

Woodside Group or Group	Woodside and its subsidiaries, which, following Implementation, will include BHP Petroleum, and a reference to 'Woodside Group Member' or a 'member of the Woodside Group' is to Woodside or any of its subsidiaries
Woodside ADSs	American Depositary Receipts representing Woodside Shares; each Woodside ADS represents one Woodside Share
Woodside Board	see "Board"
Woodside Competing Proposal	a proposal which, if entered into or completed, would result in a party other than BHP directly or indirectly: • acquiring Woodside or a substantial part of its business or assets (or would result in a similar outcome); or • acquiring a relevant interest (as defined by the Corporations Act) in 15% or more of Woodside Shares, or which would require Woodside to abandon or not proceed with the Merger
Woodside Constitution	the constitution of Woodside, as amended or replaced from time to time
Woodside Directors	see "Directors"
Woodside Dividend	each dividend declared by Woodside that has a record date that occurs following the Effective Time, but prior to Implementation
Woodside Dividend Payment	the aggregate amount of all dividend payments in respect of all Woodside Dividends (excluding franking credits) where the dividend payment for each Woodside Dividend is the amount equal to: (1) the Equity Ratio (as defined in the Share Sale Agreement) at the time the Woodside Dividend is paid multiplied by the total amount of that Woodside Dividend (in respect of all Woodside Shares); less (2) the value of the Woodside Shares issued under Woodside's dividend reinvestment plan after the Effective Time, determined in accordance with the Share Sale Agreement
Woodside Historical Financial Information	the historical financial information of the Group as derived from the annual consolidated financial statements of the Group for the financial years ended 31 December 2021, 31 December 2020 and 31 December 2019 (in each case, prepared in accordance with Australian Accounting Standards and comply with International Financial Reporting Standards as issued by the International Accounting Standards Board) as referred to in Part 14 (*Historical Financial Information of the Merged Group*) of this Prospectus and appended at Annexure 1 or Part 24 of this Prospectus
Wood Mackenzie	Wood Mackenzie (Australia) Pty Ltd
Woodside Register	the register of members of Woodside maintained under the Corporations Act
Woodside Share Registry	Computershare Investor Services Pty Limited
Woodside Shareholder	see "Shareholder"
Woodside Shareholder Approval	approval of the Merger Resolution by Woodside Shareholders
Woodside Shareholders' Meeting	the meeting of Woodside shareholders to consider, amongst others, the Merger Resolution
Woodside Shares or Shares	fully paid ordinary shares in the capital of Woodside

Part 23 – Glossary of Technical Terms

1P	Proved reserves
2C	Best Estimate of Contingent resources
2P	Proved plus Probable reserves
AUD or A$	Australian dollars
APPEA	Australian Petroleum Production & Exploration Association
Appraisal well	A well drilled to follow up a discovery and evaluate its commercial potential
Average unit cash sales	Average unit cash cost of sales includes production costs, cost of royalty and excise, shipping and direct sales costs, carbon costs and insurance; excludes exploration and evaluation, general administrative and other costs, depreciation and amortisation, PRRT and income tax
Brent	Intercontinental Exchange (ICE) Brent Crude deliverable futures contract (oil price)
Cash margin	Revenue from sale of produced hydrocarbons less production costs, royalties and excise, insurance and shipping and direct sales costs, divided by revenue from sale of produced hydrocarbons
CHF	Swiss francs
Condensate	Hydrocarbons that are gaseous in a reservoir but that condense to form liquids as they rise to the surface
cps	Cents per share
EBIT	Calculated as a profit before income tax, PRRT and net finance costs
EBITDA	Calculated as a profit before income tax, PRRT, net finance costs, depreciation and amortisation and impairment
EBITDAX	Calculated as a profit before income tax, PRRT, net finance costs, depreciation and amortisation, impairment and exploration and evaluation expense
EPS	Earnings per share
Equity lifted LNG	The proportion of LNG which Woodside is entitled to lift and sell, in its own right, as a result of its participating interest in the relevant project
FID	Final Investment Decision
FX	Foreign exchange
Flaring	The controlled burning of gas found in oil and gas reservoirs
FPSO	Floating production storage and offloading
FPU	Floating production unit
Free cashflow	Cashflow from operating activities less cashflow from investing activities

FVLCD	Fair value less costs to dispose
GDP	Gross domestic product
Gearing	Net debt divided by the sum of Net debt and equity attributable to the equity holders of the relevant entity, expressed as a percentage
GPA	Gas processing agreement
Gross margin	Gross profit divided by operating revenue. Gross profit excludes income tax, PRRT, net finance costs, other income and other expenses
GSPA	Gas sale and purchase agreement
GWF	Greater Western Flank
H1, H2	Halves of the calendar year (H1 is 1 January to 30 June and H2 is 1 July to 31 December)
HSEQ	Health, safety and environment and quality
Infill well	Well drilled for the purpose of increasing production
ISO	International Organisation for Standardisation
JCC	Japanese Crude Cocktail, being the average price of customs-cleared crude oil imports into Japan as reported in customs statistics
JV	Joint venture
KGP	Karratha Gas Plant
Liquidity	Calculated as the sum of cash on hand and undrawn committed debt facilities
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTIF	Lost time injury frequency
MCF	thousand cubic feet
MOU	Memorandum of understanding
Net debt	Total debt and lease liabilities less cash and cash equivalents
NGL	natural gas liquids
NOC	government-backed national oil company
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NOPTA	National Offshore Petroleum Titles Administrator
NPAT	Net profit after tax
NT	Northern Territory

NWS	North West Shelf
OPEC	Organization of Petroleum Exporting Countries
ORO	Other resource owners
PEP	Petroleum exploration permit
PRRT	Petroleum Resources Rent Tax
PSC	Production sharing contract
PSE	Process safety event
Q1, Q2, Q3, Q4	Quarters of the calendar year (Q1 is 1 January to 31 March, Q2 is 1 April to 30 June, Q3 is 1 July to 30 September, Q4 is 1 October to 31 December)
RAP	Woodside's Reconciliation Action Plan
Return on equity	Return on shareholder funds is calculated as NPAT (excluding non-controlling interests) divided by equity attributable to the equity holders of the parent
RFSU	Ready for start-up
ROACE	Return on average capital employed, calculated as EBIT divided by average non-current liabilities and average equity attributable to equity holders of the parent
RSSD	Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore
Spudded	Commenced well-drilling process
Tier 1 PSE	A typical Tier 1 process safety event is loss of containment of hydrocarbons greater than 500 kg (in any one-hour period)
Tier 2 PSE	A typical Tier 2 process safety event is loss of containment of hydrocarbons greater than 50 kg but less than 500 kg (in any one-hour period)
TRIR	Total recordable injury rate. The number of recordable injuries (fatalities, lost workday cases, restricted workday cases and medical treatment cases) per 1,000,000 work hours
TSR	Total shareholder return
Unit production	Production cost (US$ million) divided by production volume (MMboe)
U.S., USA or the United States	United States of America
USD or US$	US dollars
WA	Western Australia
WTI	West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States

Units of measure	
bbl	Barrel
bbl/d	barrels per day
Bcf	billion cubic feet
boe	barrel of oil equivalent
CO_2-e	carbon dioxide equivalent
kPa	thousand Pascals
km	kilometres
kt	thousand tonnes
MMbbl	million barrels
MMbbl/d	million barrels per day
MMboe	million barrels of oil equivalent
MMBtu	million British thermal units
MMscf	million standard cubic feet
MMscf/d	million standard cubic feet per day
MPa	million Pascals
Mtpa	million tonnes per annum
psi	pounds per square inch
PJ	petajoule
t	tonnes
Tcf	trillion cubic feet
TJ	terajoules

Conversion factors[68]		
Product	**Factor**	**Conversion factors[68]**
Pipeline natural gas	1 TJ	163.6 boe
Liquefied natural gas (LNG)	1 tonne	8.9055 boe
Condensate	1 bbl	1.000 boe
Oil	1 bbl	1.000 boe
Liquefied petroleum gas (LPG)	1 tonne	8.1876 boe
Natural gas	1 MMBtu	0.1724 boe
Dry gas	1 MMboe	5.7 Bcf

[68] Minor changes to some conversion factors can occur over time due to gradual changes in the process stream. Except as otherwise disclosed, the conversion factors in this table are applied in this Prospectus.

Part 24 – Annexures

ANNEXURE 1 – WOODSIDE HISTORICAL FINANCIAL INFORMATION

a) HISTORICAL FINANCIAL INFORMATION FOR YEAR END 31 DECEMBER 2019

b) HISTORICAL FINANCIAL INFORMATION FOR YEAR END 31 DECEMBER 2020

c) HISTORICAL FINANCIAL INFORMATION FOR YEAR END 31 DECEMBER 2021

FINANCIAL STATEMENTS

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Significant changes in the current reporting period

The financial performance and position of the Group were particularly affected by the following events and transactions during the reporting period:

- On 10 February 2021, the Group redeemed the $700 million 2021 US bond (refer to Note C.2).
- On 18 May 2021, the Group exited its 50% non-operated participating interest in the Kitimat LNG development. A net expense of $33 million, reflecting various exit costs, was recognised in the period (refer to Note A.1).
- On 7 July 2021, the Group completed the acquisition of FAR Senegal RSSD SA's interest in the Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore (RSSD) Joint Venture (refer to Note B.5).
- On 15 November 2021, the Group entered into a sale and purchase agreement with Global Infrastructure Partners for the sale of 49% of the Pluto Train 2 Joint Venture. As at 31 December 2021, the transaction has not been completed. Pluto Train 2 assets of $252 million have been reclassified to non-current assets held for sale as at 31 December 2021 (refer to Note B.6).
- On 22 November 2021, the Group took unconditional FID on the Scarborough and Pluto Train 2 developments. Related exploration and evaluation assets were transferred to oil and gas properties (refer to Notes B.2 and B.3). In addition, FID triggered contingent payments of $300 million and $150 million to ExxonMobil and BHP Group respectively, which have been capitalised to oil and gas properties (refer to Note B.3).
- The Group decided to withdraw from its interests in Myanmar and capitalised costs of $209 million were expensed (refer to Note B.2).
- The Group recognised impairment reversals of $1,058 million (refer to Note B.4).
- The Group hedged an increased percentage of its exposure to commodity price and foreign exchange risk through commodity swaps and foreign exchange forward derivatives (refer to Note D.6).

CONSOLIDATED INCOME STATEMENT

for the year ended 31 December 2021

	Notes	2021 US$m	2020 US$m
Operating revenue	A.1	**6,962**	3,600
Cost of sales	A.1	**(3,845)**	(2,985)
Gross profit		**3,117**	615
Other income	A.1	**139**	(36)
Other expenses	A.1	**(811)**	(481)
Impairment losses	A.1	**(10)**	(5,269)
Impairment reversals	A.1	**1,058**	-
Profit/(loss) before tax and net finance costs		**3,493**	(5,171)
Finance income		**27**	58
Finance costs	A.2	**(230)**	(327)
Profit/(loss) before tax		**3,290**	(5,440)
Petroleum resource rent tax (expense)/benefit	A.5	**(297)**	439
Income tax (expense)/benefit	A.5	**(957)**	1,026
Profit/(loss) after tax		**2,036**	(3,975)
Profit/(loss) attributable to:			
Equity holders of the parent		**1,983**	(4,028)
Non-controlling interest	E.8	**53**	53
Profit/(loss) for the period		**2,036**	(3,975)
Basic earnings/(losses) per share attributable to equity holders of the parent (US cents)	A.4	**206.0**	(423.5)
Diluted earnings/(losses) per share attributable to equity holders of the parent (US cents)	A.4	**204.1**	(423.5)

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

for the year ended 31 December 2021

	2021 US$m	2020 US$m
Profit/(loss) for the period	**2,036**	(3,975)
Other comprehensive income/(loss)		
Items that may be reclassified to the income statement in subsequent periods:		
Loss on cash flow hedges (refer to Note D.6 for more details)	**(390)**	(136)
Loss on cash flow hedges reclassified to the income statement	**66**	52
Tax recognised within other comprehensive income	**(5)**	25
Items that will not be reclassified to the income statement in subsequent periods:		
Remeasurement gains on defined benefit plan	**13**	2
Other comprehensive income/(loss) for the period, net of tax	**(316)**	(57)
Total comprehensive income/(loss) for the period	**1,720**	(4,032)
Total comprehensive income/(loss) attributable to:		
Equity holders of the parent	**1,667**	(4,085)
Non-controlling interest	**53**	53
Total comprehensive income/(loss) for the period	**1,720**	(4,032)

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

as at 31 December 2021

	Notes	2021 US$m	2020 US$m
Current assets			
Cash and cash equivalents	C.1	**3,025**	3,604
Receivables	D.2	**368**	303
Inventories	D.3	**202**	125
Other financial assets	D.6	**320**	172
Other assets		**109**	48
Non-current assets held for sale	B.6	**254**	-
Total current assets		**4,278**	4,252
Non-current assets			
Receivables	D.2	**686**	423
Inventories	D.3	**19**	40
Other financial assets	D.6	**107**	54
Other assets		**34**	55
Exploration and evaluation assets	B.2	**614**	2,045
Oil and gas properties	B.3	**18,434**	15,267
Other plant and equipment		**215**	199
Deferred tax assets	A.5	**1,007**	1,304
Lease assets	D.7	**1,080**	984
Total non-current assets		**22,196**	20,371
Total assets		**26,474**	24,623
Current liabilities			
Payables	D.4	**639**	505
Interest-bearing liabilities	C.2	**277**	776
Other financial liabilities	D.6	**411**	37
Other liabilities		**86**	136
Provisions	D.5	**605**	500
Tax payable	A.5	**413**	46
Lease liabilities	D.7	**191**	94
Total current liabilities		**2,622**	2,094
Non-current liabilities			
Interest-bearing liabilities	C.2	**5,153**	5,438
Deferred tax liabilities	A.5	**878**	549
Other financial liabilities	D.6	**161**	34
Other liabilities		**36**	42
Provisions	D.5	**2,219**	2,407
Lease liabilities	D.7	**1,176**	1,184
Total non-current liabilities		**9,623**	9,654
Total liabilities		**12,245**	11,748
Net assets		**14,229**	12,875
Equity			
Issued and fully paid shares	C.3	**9,409**	9,297
Shares reserved for employee share plans	C.3	**(30)**	(23)
Other reserves	C.4	**683**	1,403
Retained earnings		**3,381**	1,398
Equity attributable to equity holders of the parent		**13,443**	12,075
Non-controlling interest	E.8	**786**	800
Total equity		**14,229**	12,875

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

for the year ended 31 December 2021

	Notes	2021 US$m	2020 US$m
Cash flows from operating activities			
Profit/(loss) after tax for the period		**2,036**	(3,975)
Adjustments for:			
Non-cash items			
Depreciation and amortisation		**1,582**	1,730
Depreciation of lease assets		**108**	94
Change in fair value of derivative financial instruments		**31**	31
Net finance costs		**203**	269
Tax expense/(benefit)		**1,254**	(1,465)
Exploration and evaluation written off	B.2	**265**	2
Impairment losses	B.4	**10**	5,269
Impairment reversals	B.4	**(1,058)**	-
Restoration		**68**	28
Onerous contracts provision		**(95)**	347
Other		**30**	(12)
Changes in assets and liabilities			
(Increase)/decrease in trade and other receivables		**(39)**	41
(Increase)/decrease in inventories		**(4)**	51
Increase in lease assets		**(16)**	-
(Decrease)/increase in provisions		**(75)**	155
(Decrease)/increase in lease liabilities		**(25)**	40
Increase in other assets and liabilities		**(128)**	(137)
Increase/(decrease) in trade and other payables		**75**	(121)
Cash generated from operations		**4,222**	2,347
Purchases of shares and payments relating to employee share plans		**(47)**	(32)
Interest received		**11**	64
Dividends received		**6**	4
Borrowing costs relating to operating activities		**(91)**	(180)
Income tax paid		**(271)**	(331)
Payments for restoration		**(38)**	(23)
Net cash from operating activities		**3,792**	1,849
Cash flows used in investing activities			
Payments for capital and exploration expenditure		**(2,406)**	(1,418)
Borrowing costs relating to investing activities		**(126)**	(57)
Advances to other external entities		**(206)**	(110)
Proceeds from disposal of non-current assets		**9**	-
Payments for acquisition of joint arrangements	B.5	**(212)**	(527)
Net cash used in investing activities		**(2,941)**	(2,112)
Cash flows used in financing activities			
Proceeds from borrowings	C.2	**-**	600
Repayment of borrowings	C.2	**(784)**	(83)
Borrowing costs relating to financing activities		**(15)**	(21)
Repayment of lease liabilities		**(155)**	(71)
Borrowing costs relating to lease liabilities		**(89)**	(86)
Contributions to non-controlling interests		**(92)**	(111)
Dividends paid (net of DRP)		**(289)**	(454)
Net proceeds from share issuance		**-**	23
Net cash used in financing activities		**(1,424)**	(203)
Net decrease in cash held		**(573)**	(466)
Cash and cash equivalents at the beginning of the period		**3,604**	4,058
Effects of exchange rate changes		**(6)**	12
Cash and cash equivalents at the end of the period	C.1	**3,025**	3,604

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
for the year ended 31 December 2021

	Issued and fully paid shares	Shares reserved for employee share plans	Employee benefits reserve	Foreign currency translation reserve	Hedging reserve	Distributable profits reserve	Retained earnings	Equity holders of the parent	Non-controlling interest	Total equity
Notes	C.3	C.3	C.4	C.4	C.4	C.4			E.8	
	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m
At 1 January 2021	**9,297**	**(23)**	**219**	**793**	**(71)**	**462**	**1,398**	**12,075**	**800**	**12,875**
Profit for the period	**-**	**-**	**-**	**-**	**-**	**-**	**1,983**	**1,983**	**53**	**2,036**
Other comprehensive income/(loss)	**-**	**-**	**13**	**-**	**(329)**	**-**	**-**	**(316)**	**-**	**(316)**
Total comprehensive income/(loss) for the period	**-**	**-**	**13**	**-**	**(329)**	**-**	**1,983**	**1,667**	**53**	**1,720**
Dividend Reinvestment Plan	**112**	**-**	**-**	**-**	**-**	**-**	**-**	**112**	**-**	**112**
Employee share plan purchases	**-**	**(47)**	**-**	**-**	**-**	**-**	**-**	**(47)**	**-**	**(47)**
Employee share plan redemptions	**-**	**40**	**(40)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Share-based payments (net of tax)	**-**	**-**	**40**	**-**	**-**	**-**	**-**	**40**	**-**	**40**
Dividends paid	**-**	**-**	**-**	**-**	**-**	**(404)**	**-**	**(404)**	**(67)**	**(471)**
At 31 December 2021	**9,409**	**(30)**	**232**	**793**	**(400)**	**58**	**3,381**	**13,443**	**786**	**14,229**
At 1 January 2020	9,010	(39)	211	793	(12)	-	6,654	16,617	792	17,409
Transfers	-	-	-	-	-	710	(710)	-	-	-
Profit/(loss) for the period	-	-	-	-	-	-	(4,028)	(4,028)	53	(3,975)
Other comprehensive income/(loss)	-	-	2	-	(59)	-	-	(57)	-	(57)
Total comprehensive income/(loss) for the period	-	-	2	-	(59)	-	(4,028)	(4,085)	53	(4,032)
Dividend Reinvestment Plan	264	-	-	-	-	-	-	264	-	264
Shares issued	23	-	-	-	-	-	-	23	-	23
Employee share plan purchases	-	(32)	-	-	-	-	-	(32)	-	(32)
Employee share plan redemptions	-	48	(48)	-	-	-	-	-	-	-
Share-based payments (net of tax)	-	-	54	-	-	-	-	54	-	54
Dividends paid	-	-	-	-	-	(248)	(518)	(766)	(45)	(811)
At 31 December 2020	9,297	(23)	219	793	(71)	462	1,398	12,075	800	12,875

The accompanying notes form part of the Financial Statements.

NOTES TO THE FINANCIAL STATEMENTS
for the year ended 31 December 2021

About these statements
Woodside Petroleum Ltd and its controlled entities (Woodside or the Group) is a for-profit entity limited by shares, incorporated and domiciled in Australia. Its shares are publicly traded on the Australian Securities Exchange. The nature of the operations and the principal activities of the Group are described in the Directors' Report and in the segment information in Note A.1.

The financial statements were authorised for issue in accordance with a resolution of the directors on 17 February 2022.

Statement of compliance
The financial statements are general purpose financial statements, which have been prepared in accordance with the requirements of the *Corporations Act 2001*, Australian Accounting Standards (AASBs) and other authoritative pronouncements of the Australian Accounting Standards Board. The financial statements comply with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

The accounting policies are consistent with those disclosed in the 2020 Financial Statements, except for the impact of all new or amended standards and interpretations adopted with effect from 1 January 2021. The adoption of these standards and interpretations did not result in any significant changes to the Group's accounting policies, with the exception of AASB 2020-8 *Amendments to Australian Accounting Standards - Interest Rate Benchmark Reform* (refer to Note E.9(c)).

Estimates and judgements reflect current market conditions, including the impact of COVID-19. Estimates used for impairment assessments and the measurement of onerous contracts are disclosed in Notes B.4 and D.5 respectively. Given ongoing economic uncertainty, these assumptions could change in the future.

Currency
The functional and presentation currency of Woodside Petroleum Ltd and all its subsidiaries is the US dollar.

Transactions in foreign currencies are initially recorded in the functional currency of the transacting entity at the exchange rates ruling at the date of transaction. Monetary assets and liabilities denominated in foreign currencies at the reporting date are translated at the rates of exchange ruling at that date. Exchange differences in the consolidated financial statements are taken to the income statement.

Rounding of amounts
The amounts contained in these financial statements have been rounded to the nearest million dollars under the option available to the Group under Australian Securities and Investments Commission (ASIC) Corporations (Rounding in Financial/Directors' Reports) Instrument 2016/191 dated 24 March 2016, unless otherwise stated.

Basis of preparation
The financial statements have been prepared on a historical cost basis, except for derivative financial instruments and certain other financial assets and financial liabilities, which have been measured at fair value or amortised cost adjusted for changes in fair value attributable to the risks that are being hedged in effective hedge relationships. Where not carried at fair value, if the carrying value of financial assets and financial liabilities does not approximate their fair value, the fair value has been included in the notes to the financial statements.

The financial statements comprise the financial results of the Group as at 31 December each year (refer to Note E.8).

Subsidiaries are fully consolidated from the date on which control is obtained by the Group and cease to be consolidated from the date at which the Group ceases to have control.

The subsidiaries of the Group have the same reporting period and accounting policies as the parent company. All intercompany balances and transactions, including unrealised profits and losses arising from intra-group transactions, have been eliminated in full.

Non-controlling interests are allocated their share of the net profit after tax in the consolidated income statement and their share of other comprehensive income net of tax in the consolidated statement of comprehensive income, and are presented within equity in the consolidated statement of financial position, separately from parent shareholders' equity.

The consolidated financial statements provide comparative information in respect of the previous period. Where required, a reclassification of items in the financial statements of the previous period has been made in accordance with the classification of items in the financial statements of the current period.

Financial and capital risk management
The Board of Directors has overall responsibility for the establishment and oversight of the Group's risk management framework, including review and approval of the Group's risk management strategy, policy and key risk parameters. The Board of Directors and the Audit and Risk Committee have oversight of the Group's internal control system and risk management process, including oversight of the internal audit function.

The Group's management of financial and capital risks is aimed at ensuring that available capital, funding and cash flows are sufficient to:

- meet the Group's financial commitments as and when they fall due;
- maintain the capacity to fund its committed project developments;
- pay a reasonable dividend; and
- maintain a long-term credit rating of not less than 'investment grade'.

The Group monitors and tests its forecast financial position against these criteria and, in general, will undertake hedging activity only when necessary to ensure that these objectives are achieved.

Other circumstances that may lead to hedging activities include the management of exposures relating to trading activities and the underpinning of the economics of a new project. It is, and has been throughout the period, the Group Treasury policy that no speculative trading in financial instruments shall be undertaken. Refer to the Risk section of Corporate on pages 51-54 for more information on the Group's objectives, policies and processes for managing financial risk.

The below risks arise in the normal course of the Group's business. Risk information can be found in the following sections:

Section A	Commodity price risk	Page 102
Section A	Foreign exchange risk	Page 102
Section C	Capital risk	Page 122
Section C	Liquidity risk	Page 122
Section C	Interest rate risk	Page 122
Section D	Credit risk	Page 126

Key estimates and judgements

In applying the Group's accounting policies, management continually evaluates judgements, estimates and assumptions based on experience and other factors, including expectations of future events that may have an impact on the Group. All judgements, estimates and assumptions made are believed to be reasonable based on the most current set of circumstances known to management, and actual results may differ. Significant judgements, estimates and assumptions made by management in the preparation of these financial statements are found in the following notes:

NOTES TO THE FINANCIAL STATEMENTS A. EARNINGS FOR THE YEAR

for the year ended 31 December 2021

In this section

This section addresses financial performance of the Group for the reporting period including, where applicable, the accounting policies applied and the key estimates and judgements made. This section also includes the tax position of the Group for and at the end of the reporting period.

Key financial and capital risks in this section

Commodity price risk management

The Group's revenue is exposed to commodity price fluctuations through the sale of hydrocarbons. Commodity price risks are measured by monitoring and stress testing the Group's forecast financial position to sustained periods of low oil and gas prices. This analysis is regularly performed on the Group's portfolio and as required for discrete projects and transactions.

The Group's management of commodity price risk includes the use of commodity swap derivatives to hedge its exposure (refer to Note D.6). The hedged exposure includes LNG revenue related to produced volumes and revenues derived from trading operations. Commodity swap derivatives protect the Group against downside risk within its strategic and trading portfolio.

As at the reporting date, the Group held hedging financial instruments with a net liability carrying value of $431 million (2020: $9 million) exposed to commodity price risk. An increase in relevant commodity prices of 10% would decrease the instruments' carrying value by $255 million, the effect of which would be recognised within reserves and/or the income statement in accordance with hedge accounting application. A 10% decrease would have the same but opposite effect. The analysis assumes that all other variables remain constant (including the price on underlying physical exposures).

Foreign exchange risk management

Foreign exchange risk arises from future commitments, financial assets and financial liabilities that are not denominated in US dollars. The majority of the Group's revenue is denominated in US dollars. The Group is exposed to foreign currency risk arising from operating and capital expenditure incurred in currencies other than US dollars, particularly Australian dollars.

The Group's management of foreign exchange risk relating to capital expenditure includes the use of forward exchange contract derivatives to hedge its exposure (refer to Note D.6).

As at the reporting date, the Group held hedging financial instruments with a net asset carrying value of $10 million (2020: nil) exposed to foreign exchange risk.

Measuring the exposure to foreign exchange risk is achieved by regularly monitoring and performing sensitivity analysis on the Group's financial position.

A reasonably possible change in the exchange rate of the US dollar to the Australian dollar (+12%/-12% (2020: +12%/-12%)), with all other variables held constant, would not have a material impact on the Group's equity or the profit or loss in the current period. Refer to Notes C1, C2, D2, D4 and D7 for details of the denominations of cash and cash equivalents, interest-bearing liabilities, receivables, payables and lease liabilities held at 31 December 2021.

In order to hedge the foreign exchange risk and interest rate risk (refer to Section C) of a Swiss Franc (CHF) denominated medium term note, Woodside holds a number of cross-currency interest rate swaps (refer to Note C.2 and D.6). The aim of this hedge is to convert the fixed interest CHF bond into variable interest US dollar debt. The Group also entered into foreign exchange forward contracts to fix the Australian dollar to US dollar exchange rate in relation to a portion of the Australian dollar denominated capital expenditure expected to be incurred under the Scarborough development (refer to Note D.6).

A.1 Segment revenue and expenses

Operating segment information

The Group has identified its operating segments based on the internal reports that are reviewed and used by the executive management team in assessing performance and in determining the allocation of resources.

The Group has reviewed its operating segments and has identified the Sangomar and Scarborough Development as separate operating segments within Development due to the progress and materiality of the related projects. The 2020 amounts have been restated to reflect this change.

Management monitors the performance of the operating results of the segments separately for the purpose of making decisions about resource allocation and performance assessment. The performance of operating segments is evaluated based on profit before tax and net finance costs and is measured in accordance with the Group's accounting policies.

Financing requirements, including cash and debt balances, finance income, finance costs and taxes are managed at a Group level.

Operating segments outlined below are identified by management based on the nature and geographical location of the business or venture.

Producing

North West Shelf Project – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas, condensate and liquefied petroleum gas in assigned permit areas.

Pluto LNG – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas and condensate in assigned permit areas.

Australia Oil – Exploration, evaluation, development, production and sale of crude oil in assigned permit areas (North West Shelf, Greater Enfield and Vincent).

Wheatstone – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas and condensate in assigned permit areas.

Development

Scarborough – Exploration, evaluation and development of liquified natural gas, pipeline natural gas and condensate in assigned permit areas.

Sangomar – Exploration, evaluation and development of crude oil in assigned permit areas.

Other development segments – This segment comprises exploration, evaluation and development of liquefied natural gas, pipeline natural gas and condensate in the Browse, Kitimat and Sunrise projects.

Other

Other segments – This segment comprises trading and shipping activities and activities undertaken in other international locations.

Unallocated items – Unallocated items comprise primarily corporate non-segmental items of revenue and expenses and associated assets and liabilities not allocated to operating segments as they are not considered part of the core operations of any segment.

Major customer information

The Group has two major customers which respectively account for 8% and 6% of the Group's external revenue. The sales are generated by the Pluto, North West Shelf and Wheatstone operating segments (2020: two major customers; 15% and 13% generated by Pluto and North West Shelf).

Geographic information	Revenue from external customers[1]		Non-current assets[2]	
	2021 US$m	2020 US$m	**2021 US$m**	2020 US$m
Oceania	**313**	286	**18,386**	17,559
Asia	**6,029**	3,076	**-**	229
Canada	**-**	-	**-**	34
Africa	**-**	-	**2,802**	1,244
Other	**620**	238	**1**	1
Consolidated	**6,962**	3,600	**21,189**	19,067

1. Revenue is attributable to geographic region based on the location of the customer.
2. Non-current assets exclude deferred tax of $1,007 million (2020: $1,304 million).

Recognition and measurement

Revenue from contracts with customers

Revenue is recognised when or as the Group transfers control of products or provides services to a customer at the amount to which the Group expects to be entitled. If the consideration includes a variable component, the Group estimates the amount of the expected consideration receivable. Variable consideration is estimated throughout the contract and is constrained until it is highly probable a significant revenue reversal in the amount of cumulative revenue recognised will not occur.

- Revenue from sale of hydrocarbons - Revenue from the sale of hydrocarbons is recognised at a point in time when control of the product is transferred to the customer, which is typically on delivery.

  Revenue from take or pay contracts is recorded as unearned revenue until the product has been drawn by the customer (transfer of control), at which time it is recognised in earnings.
- Other operating revenue - Revenue earned from LNG processing and other services is recognised over time as the services are rendered.

Expenses

- Royalties, excise and levies - Royalties, excise and levies under existing regimes are considered to be production-based taxes and are therefore accrued on the basis of the Group's entitlement to physical production.
- Depreciation and amortisation - Refer to Note B.3.
- Impairment and impairment reversals - Refer to Note B.4.
- Leases - Refer to Note D.7.
- Employee benefits - Refer to Note E.2.

Key estimates and judgements

Revenue from contracts with customers

Judgement is required to determine the point at which the customer obtains control of hydrocarbons. Factors including transfer of legal title, transfer of significant risks and rewards of ownership and the existence of a present right to payment for the hydrocarbons typically result in control transferring on delivery of hydrocarbons at port of loading or port of discharge.

The transaction price at the date control passes for sales made subject to provisional pricing periods in oil and condensate contracts is determined with reference to quoted commodity prices.

Judgement is also used to determine if it is probable that a significant reversal will occur in relation to revenue recognised during open pricing periods in LNG contracts. The Group estimates variable consideration based on reasonably available information from contract negotiations and market indicators.

Progress of performance obligations for LNG processing services revenue recognised over time is measured using the output method which most accurately measures the progress towards satisfaction of the performance obligation of the services provided.

A.1 Segment revenue and expenses (cont.)

	Producing				Development			Other		
	North West Shelf	Pluto	Australia Oil	Wheatstone	Scarborough	Sangomar	Other developments	Other segments	Unallocated items	Consolidated
	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m
Liquefied natural gas	1,209	2,415	-	581	-	-	-	1,154	-	5,359
Domestic gas	8	19	-	16	-	-	-	-	-	43
Condensate	253	215	-	175	-	-	-	-	-	643
Oil	-	-	673	-	-	-	-	-	-	673
Liquefied petroleum gas	60	-	-	-	-	-	-	-	-	60
Revenue from sale of hydrocarbons	1,530	2,649	673	772	-	-	-	1,154	-	6,778
Processing and services revenue	-	143	-	-	-	-	-	-	-	143
Shipping and other revenue	-	2	-	-	-	-	-	39	-	41
Other revenue	-	145	-	-	-	-	-	39	-	184
Operating revenue[1]	1,530	2,794	673	772	-	-	-	1,193	-	6,962
Production costs	(116)	(192)	(109)	(72)	-	-	-	-	8	(481)
Royalties, excise and levies	(200)	(9)	(7)	(2)	-	-	-	-	-	(218)
Insurance	(7)	(19)	(4)	(2)	-	-	-	-	1	(31)
Inventory movement	-	1	8	8	-	-	-	-	-	17
Costs of production	(323)	(219)	(112)	(68)	-	-	-	-	9	(713)
Land and buildings	(3)	(28)	-	(20)	-	-	-	-	-	(51)
Transferred exploration and evaluation	(9)	(27)	(21)	(22)	-	-	-	-	-	(79)
Plant and equipment	(183)	(827)	(199)	(207)	-	-	-	-	-	(1,416)
Marine vessels and carriers	(3)	-	-	-	-	-	-	-	-	(3)
Oil and gas properties depreciation and amortisation	(198)	(882)	(220)	(249)	-	-	-	-	-	(1,549)
Shipping and direct sales costs[2]	(45)	(70)	-	(42)	-	-	-	(53)	-	(210)
Trading costs[3]	-	(138)	-	-	-	-	-	(1,357)	-	(1,495)
Other hydrocarbon costs	-	-	-	(6)	-	-	-	-	-	(6)
Other cost of sales	-	(11)	-	-	-	-	-	(1)	-	(12)
Movement in onerous contract provision[4]	-	-	-	-	-	-	-	140	-	140
Other cost of sales	(45)	(219)	-	(48)	-	-	-	(1,271)	-	(1,583)
Cost of sales	(566)	(1,320)	(332)	(365)	-	-	-	(1,271)	9	(3,845)
Gross profit	964	1,474	341	407	-	-	-	(78)	9	3,117
Other income[5]	17	75	5	(1)	-	-	(1)	-	44	139
Exploration and evaluation expenditure	(2)	(2)	(1)	(1)	-	(3)	(2)	(43)	-	(54)
Amortisation	-	-	-	-	-	-	-	(3)	-	(3)
Write-offs[6]	-	-	-	-	-	-	-	(265)	-	(265)
Exploration and evaluation	(2)	(2)	(1)	(1)	-	(3)	(2)	(311)	-	(322)
General, administrative and other costs	(1)	(2)	-	(1)	-	5	(1)	(5)	(153)	(158)
Depreciation of other plant and equipment	-	-	-	-	-	-	-	-	(30)	(30)
Depreciation of lease assets	(1)	(27)	-	-	-	-	-	(47)	(33)	(108)
Restoration movement	15	-	(95)	-	-	-	12	-	-	(68)
Other[7]	(10)	(3)	(6)	(38)	-	-	(32)	-	(36)	(125)
Other costs	3	(32)	(101)	(39)	-	5	(21)	(52)	(252)	(489)
Other expenses	1	(34)	(102)	(40)	-	2	(23)	(363)	(252)	(811)
Impairment losses	-	-	-	(10)	-	-	-	-	-	(10)
Impairment reversals[8]	376	682	-	-	-	-	-	-	-	1,058
Profit/(loss) before tax and net finance costs	1,358	2,197	244	356	-	2	(24)	(441)	(199)	3,493

1. Operating revenue includes revenue from contracts with customers of $6,923 million and sub-lease income of $39 million disclosed within shipping and other revenue.
2. Includes repurchase and cancellation costs to optimise Group operating revenues.
3. Trading costs within Other segments relate to purchase costs of non-produced volumes (including Corpus Christi) and other volumes purchased to optimise produced LNG revenue.
4. Comprises provisions used of $45 million and changes in estimates of $95 million. Refer to Note D.5 for more details.
5. Includes other income of $67 million relating to Pluto volumes delivered into Wheatstone's sales commitments and net foreign exchange gains of $44 million.
6. $56 million relates to costs of unsuccessful wells. $209 million relates to capitalised costs written off due to the Group's decision to withdraw from its interests in Myanmar. Refer to Note B.2.
7. Includes net loss on hedging activities of $91 million and other expenses not associated with the ongoing operations of the business. The Other developments segment also includes $33 million for various costs relating to Woodside's exit from the Kitimat LNG development.
8. Impairment reversals on oil and gas properties. Refer to Note B.4 for more details.

A.1 Segment revenue and expenses (cont.)

	Producing				Development			Other		
	North West Shelf	Pluto	Australia Oil	Wheatstone	Scarborough	Sangomar	Other developments	Other segments	Unallocated items	Consolidated
	2020 US$m	2020 US$m	2020 US$m	2020 US$m	2020[5] US$m	2020[5] US$m	2020[5] US$m	2020 US$m	2020 US$m	2020 US$m
Liquefied natural gas[1]	722	1,320	-	365	-	-	-	112	-	2,519
Domestic gas	44	11	-	18	-	-	-	-	-	73
Condensate	194	114	-	103	-	-	-	-	-	411
Oil	-	-	432	-	-	-	-	-	-	432
Liquefied petroleum gas	16	-	-	-	-	-	-	-	-	16
Revenue from sale of hydrocarbons	976	1,445	432	486	-	-	-	112	-	3,451
Processing and services revenue	-	142	-	-	-	-	-	-	-	142
Shipping and other revenue	-	-	-	-	-	-	-	7	-	7
Other revenue	-	142	-	-	-	-	-	7	-	149
Operating revenue	976	1,587	432	486	-	-	-	119	-	3,600
Production costs	(118)	(189)	(107)	(72)	-	-	-	-	8	(478)
Royalties, excise and levies	(79)	-	(3)	-	-	-	-	-	-	(82)
Insurance	(7)	(19)	(3)	(3)	-	-	-	-	1	(31)
Inventory movement	(1)	(7)	(21)	(3)	-	-	-	-	-	(32)
Costs of production	(205)	(215)	(134)	(78)	-	-	-	-	9	(623)
Land and buildings	(4)	(27)	-	(24)	-	-	-	-	-	(55)
Transferred exploration and evaluation	(13)	(32)	(32)	(22)	-	-	-	-	-	(99)
Plant and equipment	(228)	(823)	(251)	(231)	-	-	-	-	-	(1,533)
Marine vessels and carriers	(2)	-	-	-	-	-	-	-	-	(2)
Oil and gas properties depreciation and amortisation	(247)	(882)	(283)	(277)	-	-	-	-	-	(1,689)
Shipping and direct sales costs	(49)	(53)	-	(44)	-	-	-	35	-	(111)
Trading costs	(8)	(49)	-	(10)	-	-	-	(144)	-	(211)
Other hydrocarbon costs	-	-	-	(4)	-	-	-	-	-	(4)
Other cost of sales	-	-	-	-	-	-	-	-	-	-
Movement in onerous contract provision[2]	-	-	-	-	-	-	-	(347)	-	(347)
Other cost of sales	(57)	(102)	-	(58)	-	-	-	(456)	-	(673)
Cost of sales	(509)	(1,199)	(417)	(413)	-	-	-	(456)	9	(2,985)
Gross profit	467	388	15	73	-	-	-	(337)	9	615
Other income[3]	12	(6)	-	1	(3)	-	-	(42)	2	(36)
Exploration and evaluation expenditure	(3)	(1)	(1)	(3)	-	(2)	(1)	(56)	-	(67)
Amortisation	-	-	-	-	-	-	-	(12)	-	(12)
Write-offs	-	-	-	-	-	-	-	(2)	-	(2)
Exploration and evaluation	(3)	(1)	(1)	(3)	-	(2)	(1)	(70)	-	(81)
General, administrative and other costs	(1)	(1)	(1)	(1)	(3)	2	(13)	(6)	(166)	(190)
Depreciation of other plant and equipment	-	-	-	-	-	-	-	-	(29)	(29)
Depreciation of lease assets	-	(26)	-	-	-	-	-	(34)	(34)	(94)
Restoration movement	(5)	-	(62)	-	-	-	39	-	-	(28)
Other[3]	(15)	12	(12)	8	-	-	(1)	42	(93)	(59)
Other costs	(21)	(15)	(75)	7	(3)	2	25	2	(322)	(400)
Other expenses	(24)	(16)	(76)	4	(3)	-	24	(68)	(322)	(481)
Impairment losses[4]	(454)	(1,291)	(674)	(1,401)	-	(321)	(977)	(151)	-	(5,269)
Impairment reversals	-	-	-	-	-	-	-	-	-	-
Profit/(loss) before tax and net finance costs	1	(925)	(735)	(1,323)	(6)	(321)	(953)	(598)	(311)	(5,171)

1. Includes an adjustment of $113 million related to price reviews currently under negotiation for multiple contracts across North West Shelf and Pluto, reducing revenue recognised in the current and prior periods and increasing other liabilities.
2. Comprised of the recognition of an onerous contract provision $447 million, offset by changes in estimates of $54 million, provisions used of $41 million and a revision of discount rates of $5 million. Refer to Note D.5 for more details.
3. Includes foreign exchange gains and losses, gains and losses on hedging activities, cancellation costs and other expenses not associated with the ongoing operations of the business.
4. The impairment losses represent charges on exploration and evaluation of $1,557 million and oil and gas properties of $3,712 million.
5. The 2020 amounts have been restated to reflect the changes in the Development segment.

A.2 Finance costs

	2021 US$m	2020 US$m
Interest on interest-bearing liabilities	201	237
Interest on lease liabilities	97	86
Accretion charge	29	32
Other finance costs	26	29
Less: Finance costs capitalised against qualifying assets	(123)	(57)
	230	327

A.3 Dividends paid and proposed

Woodside Petroleum Ltd, the parent entity, paid and proposed dividends set out below:

	2021 US$m	2020 US$m
(a) Dividends paid during the financial year		
Prior year fully franked final dividend US$0.12, paid on 24 March 2021 (2020: US$0.55, paid on 20 March 2020)	115	518
Current year fully franked interim dividend US$0.30, paid on 24 September 2021 (2020: US$0.26, paid on 18 September 2020)	289	248
	404	766
(b) Dividend declared subsequent to the reporting period (not recorded as a liability)		
Final dividend US$1.05 (2020: US$0.12)	1,018	115
(c) Other information		
Franking credits available for subsequent periods	1,744	1,823
Current year dividends per share (US cents)	135	38

The Dividend Reinvestment Plan (DRP) was approved by the shareholders at the Annual General Meeting in 2003 for activation as required to fund future growth. The DRP was reactivated for the 2019 interim dividend and remains in place until further notice.

A.4 Earnings/(losses) per share

	2021	2020
Profit/(loss) attributable to equity holders of the parent (US$m)	1,983	(4,028)
Weighted average number of shares on issue for basic earnings/(loss) per share	962,604,811	951,113,086
Effect of dilution from contingently issuable shares	9,023,439	-
Weighted average number of shares on issue adjusted for the effect of dilution[1]	971,628,250	951,113,086
Basic earnings/(losses) per share (US cents)	206.0	(423.5)
Diluted earnings/(losses) per share (US cents)	204.1	(423.5)

1. The contingently issuable shares in 2020 have an anti-dilutive impact.

Earnings/(losses) per share is calculated by dividing the profit/(loss) for the year attributable to ordinary equity holders of the parent by the weighted average number of ordinary shares on issue during the year. The weighted average number of shares makes allowance for shares reserved for employee share plans. Diluted earnings per share is calculated by adjusting basic earnings per share by the number of ordinary shares that would be issued on conversion of all the dilutive potential ordinary shares into ordinary shares. At 31 December 2021, 9,023,439 awards granted under the Woodside employee share plans are considered dilutive. Total outstanding share awards as at 31 December 2020 were 9,392,203 and considered anti-dilutive due to the loss position in 2020.

On 22 November 2021, Woodside and BHP Group (BHP) signed a binding share sale agreement to combine their respective oil and gas portfolios by an all stock merger (the Transaction). On completion of the Transaction, BHP's oil and gas business would merge with Woodside, and Woodside would issue new shares to be distributed to BHP shareholders. The expanded Woodside would be owned 52% by existing Woodside shareholders and 48% by existing BHP shareholders. This Transaction is not considered dilutive for the current period.

There have been no significant transactions involving ordinary shares between the reporting date and the date of completion of these financial statements.

A.5 Taxes

	2021 US$m	2020 US$m
(a) Tax expense comprises		
Petroleum resource rent tax (PRRT)		
Deferred tax expense/(benefit)	297	(439)
PRRT expense/(benefit)	297	(439)
Income tax		
Current year		
Current tax expense	658	275
Deferred tax expense/(benefit)	301	(1,308)
Adjustment to prior years		
Current tax (benefit)/expense	(20)	16
Deferred tax expense/(benefit)	18	(9)
Income tax expense/(benefit)	957	(1,026)
Tax expense/(benefit)	1,254	(1,465)
(b) Reconciliation of income tax expense		
Profit/(loss) before tax	3,290	(5,440)
PRRT (expense)/benefit	(297)	439
Profit/(loss) before income tax	2,993	(5,001)
Income tax expense/(benefit) calculated at 30%	898	(1,500)
Foreign income tax expense/(benefit)	23	(11)
Non-deductible items	7	2
Foreign expenditure not brought to account	49	473
Adjustment to prior years	(2)	7
Foreign exchange impact on tax (benefit)/expense	(18)	3
Income tax expense/(benefit)	957	(1,026)
(c) Reconciliation of PRRT benefit		
Profit/(loss) before tax	3,290	(5,440)
Non-PRRT assessable (profit)/loss	(2,134)	3,080
PRRT projects profit/(loss) before tax[1]	1,156	(2,360)
PRRT expense/(benefit) calculated at 40%[2]	462	(944)
Augmentation	(166)	(138)
Derecognition of Pluto general expenditure[1]	-	627
Other	1	16
PRRT expense/(benefit)	297	(439)
(d) Deferred tax income statement reconciliation		
PRRT		
Production and growth assets	455	(242)
Augmentation for current year	(166)	(138)
Provisions	(29)	(32)
Other	37	(27)
PRRT expense/(benefit)	297	(439)
Income tax		
Oil and gas properties	674	(981)
Exploration and evaluation assets	(204)	(210)
Provisions	(10)	(106)
PRRT liabilities	(88)	134
Lease assets and liabilities	1	(16)
Unused tax losses and tax credits	149	(149)
Non-current assets held for sale	(205)	-
Other	2	11
Income tax deferred tax expense/(benefit)	319	(1,317)
Deferred tax expense/(benefit)	616	(1,756)
(e) Deferred tax balance sheet reconciliation		
Deferred tax assets		
PRRT		
Production and growth assets	767	1,098
Augmentation for current year	166	124
Provisions	75	46
Other	(1)	36
	1,007	1,304

	2021 US$m	2020 US$m
(e) Deferred tax balance sheet reconciliation (cont.)		
Deferred tax liabilities		
PRRT		
Production and growth assets	-	224
Augmentation for current year	-	(14)
Provisions	-	(214)
Other	-	4
Income tax		
Oil and gas properties	1,520	846
Exploration and evaluation assets	51	255
Lease assets and liabilities	(38)	(39)
Provisions	(706)	(696)
PRRT liabilities	303	391
Unused tax losses and tax credits	-	(149)
Non-current assets held for sale	(205)	-
Other[3]	(47)	(59)
	878	549
(f) Tax payable reconciliation		
Income tax payable	413	46
	413	46
(g) Effective income tax rate: Australian and global operations		
Effective income tax rate[4]		
Australia	30.6%	29.6%
Global	32.0%	20.5%
(h) Current income tax expense reconciliation		
Profit/(loss) before income tax	2,993	(5,001)
Income tax expense/(benefit) at the statutory tax rate of 30%	898	(1,500)
Foreign income tax expense/(benefit)	23	(11)
Non-temporary differences[5,6]	56	475
Temporary differences: deferred tax[6]	(301)	1,308
Foreign exchange impact on tax (benefit)/expense	(18)	3
Current income tax expense	658	275

1. The net $348 million reduction of the Pluto PRRT deferred tax asset in 2020 includes derecognition of general expenditure of $627 million (based on expected future utilisation) offset by a reduction in the Pluto asset accounting base of $279 million (included within 'PRRT projects profit/(loss) before tax').
2. Includes a $226 million PRRT expense as a result of the 2021 Pluto-Scarborough impairment reversal increasing the asset accounting base and thereby reducing the deferred tax asset.
3. Includes $10 million tax expense recognised in other comprehensive income (2020: $19 million benefit).
4. The global operations effective income tax rate (ETR) is calculated as the Group's income tax expense divided by profit before income tax. The Australian operations ETR is calculated with reference to all Australian companies and excludes foreign exchange on settlement and revaluation of income tax liabilities.
5. Primarily expenditure in respect of foreign operations, including the impairment of foreign assets and onerous contract provision.
6. Excludes adjustment to prior years.

A.5 Taxes (cont.)

Tax transparency code

Woodside participates in the Australian Board of Taxation's voluntary Tax Transparency Code (TTC). To increase public confidence in the contributions and compliance of corporate taxpayers, the TTC recommends public disclosure of tax information. Woodside has addressed the recommended disclosures in two parts. The Part A disclosures are addressed within this Taxes note; the Part B disclosures are addressed in our Sustainable Development Report.

Recognition and measurement

Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset is realised. The tax rates and laws used to determine the amount are based on those that have been enacted or substantially enacted by the end of the reporting period. Income taxes relating to items recognised directly in equity are recognised in equity.

Current taxes

Current tax expense is the expected tax payable on the taxable income for the year and any adjustment to tax payable in respect of previous years.

Deferred taxes

Deferred tax expense represents movements in the temporary differences between the carrying amount of an asset or liability in the statement of financial position and its tax base.

With the exception of those noted below, deferred tax liabilities are recognised for all taxable temporary differences.

Deferred tax assets are recognised for deductible temporary differences, unused tax losses and tax credits only if it is probable that sufficient future taxable income will be available to utilise those temporary differences and losses.

Deferred tax is not recognised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of assets and liabilities in a transaction that affects neither accounting profit nor the taxable profit.

In relation to PRRT, the impact of future augmentation on expenditure is included in the determination of future taxable profits when assessing the extent to which a deferred tax asset can be recognised in the statement of financial position.

Offsetting deferred tax balances

Deferred tax assets and liabilities are offset only if there is a legally enforceable right to offset current tax assets and liabilities and when they relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities that the Group intends to settle its current tax assets and liabilities on a net basis. Refer to Notes E.8 and E.9 for detail on the tax consolidated group.

Key estimates and judgements

(a) Income tax classification

Judgement is required when determining whether a particular tax is an income tax or another type of tax. PRRT is considered, for accounting purposes, to be an income tax. Accounting for deferred tax is applied to income taxes as described above, but is not applied to other types of taxes, e.g. North West Shelf royalties, excise and levies which are recognised in cost of sales in the income statement.

(b) Deferred tax asset recognition

Australian tax losses: A deferred tax asset (DTA) of nil (2020: $149 million) has been recognised for carry forward unused tax losses and credits. The 2020 DTA was fully utilised in 2021.

Foreign tax losses: Deferred tax assets of $497 million (2020: $477 million) relating to unused foreign tax losses have not been recognised on the basis that it is not probable that the assets will be utilised based on current planned activities in those regions.

PRRT: The recoverability of PRRT deferred tax assets is primarily assessed with regard to future oil price assumptions. As a result of the Pluto impairment reversal (as disclosed in Note B.4) increasing the Pluto PRRT accounting base, the Pluto PRRT DTA has been reduced by $226 million. The Pluto PRRT DTA of $785 million continues to be recognised on the basis that it is probable that future taxable profits will be available to utilise the deductible expenditure. In determining the amount of DTA that is considered probable and eligible for recognition, forecast future taxable profits are risk-adjusted where appropriate by a market premium risk rate to reflect uncertainty inherent in long-term forecasts. A long-term bond rate of 1.5% (31 December 2020: 1.0%) was used for the purposes of augmentation. All other deferred PRRT and income tax movements are a result of the effective income tax rates applicable to each Australian or foreign jurisdiction.

Certain deferred tax assets on deductible temporary differences have not been recognised on the basis that deductions from future augmentation of the deductible temporary difference will be sufficient to offset future taxable profit. $4,507 million (2020: $4,167 million) relates to the North West Shelf Project, $1,432 million (2020: $1,345 million) relates to the quarantined exploration spend and unrecognised general spend of Pluto LNG and $1,071 million (2020: $1,049 million) relates to Wheatstone. A long-term bond rate of 1.5% (31 December 2020: 1.0%) was used for the purposes of augmentation.

Had an alternative approach been used to assess recovery of the deferred tax assets, whereby future augmentation was not included in the assessment, the additional deferred tax assets would be recognised, with a corresponding benefit to income tax expense. It was determined that the approach adopted provides the most meaningful information on the implications of the PRRT regime, whilst ensuring compliance with AASB 112 *Income Taxes*.

In this section

This section addresses the strategic growth (exploration and evaluation), core producing and development (oil and gas properties) assets position of the Group at the end of the reporting period including, where applicable, the accounting policies and key estimates and judgements applied. This section also includes the impairment position of the Group at the end of the reporting period.

B.1 Segment production and growth assets

	Producing				Development			Other	
	North West Shelf	Pluto	Australia Oil	Wheatstone	Scarborough	Sangomar	Other developments	Other	Consolidated
	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m	2021 US$m
Balance as at 31 December									
Oceania	9	-	13	4	43	-	477	-	546
Asia	-	-	-	-	-	-	-	-	-
Canada	-	-	-	-	-	-	-	-	-
Africa	-	-	-	-	-	58	-	10	68
Other	-	-	-	-	-	-	-	-	-
Total exploration and evaluation	9	-	13	4	43	58	477	10	614
Balance as at 31 December									
Land and buildings	16	321	-	401	-	-	-	1	739
Transferred exploration and evaluation	65	234	69	158	-	-	-	-	526
Plant and equipment	1,757	7,651	585	2,315	-	-	-	5	12,313
Marine vessels and carriers	8	-	-	-	-	-	-	-	8
Projects in development	226	403	10	27	1,980	2,195	-	7	4,848
Total oil and gas properties	2,072	8,609	664	2,901	1,980	2,195	-	13	18,434
Balance as at 31 December									
Land and buildings	11	52	-	3	10	11	-	290	377
Plant and equipment	-	-	-	-	-	167	-	-	167
Marine vessels and carriers	1	132	-	-	-	9	-	394	536
Total lease assets	12	184	-	3	10	187	-	684	1,080
Additions to exploration and evaluation:									
Exploration	-	-	-	1	-	7	-	34	42
Evaluation	-	-	-	-	446	-	5	2	453
Restoration	-	-	-	-	-	-	6	-	6
	-	-	-	1	446	7	11	36	501
Additions to oil and gas properties:									
Oil and gas properties	119	268	13	112	559	1,049	-	6	2,126
Capitalised borrowings costs[1]	2	20	-	15	9	77	-	-	123
Restoration	(12)	4	(13)	39	-	14	-	-	32
	109	292	-	166	568	1,140	-	6	2,281
Additions to lease assets:									
Land and buildings	-	-	-	-	-	14	-	-	14
Plant and equipment	-	-	-	-	-	205	-	-	205
Marine vessels and carriers	-	-	-	-	-	9	-	-	9
	-	-	-	-	-	228	-	-	228

1. Borrowing costs capitalised were at a weighted average interest rate of 3.6%.

Refer to Note A.1 for descriptions of the Group's segments and geographical regions.

B.1 Segment production and growth assets (cont.)

	Producing				Development			Other	
	North West Shelf	Pluto	Australia Oil	Wheatstone	Scarborough	Sangomar	Other developments	Other	Consolidated
	2020 US$m	2020 US$m	2020 US$m	2020 US$m	2020[2] US$m	2020[2] US$m	2020[2] US$m	2020 US$m	2020 US$m
Balance as at 31 December									
Oceania	9	-	13	3	1,261	-	466	-	1,752
Asia	-	-	-	-	-	-	-	229	229
Canada	-	-	-	-	-	-	-	-	-
Africa	-	-	-	-	-	51	-	13	64
Other	-	-	-	-	-	-	-	-	-
Total exploration and evaluation	9	-	13	3	1,261	51	466	242	2,045
Balance as at 31 December									
Land and buildings	9	307	-	432	-	-	-	1	749
Transferred exploration and evaluation	61	167	90	113	-	-	-	-	431
Plant and equipment	1,574	7,498	784	2,074	-	-	-	3	11,933
Marine vessels and carriers	11	-	-	-	-	-	-	-	11
Projects in development	131	549	10	395	-	-	1,055	3	2,143
Total oil and gas properties	1,786	8,521	884	3,014	-	-	1,055	7	15,267
Balance as at 31 December									
Land and buildings	12	22	-	3	4	1	33	317	392
Plant and equipment	-	-	-	-	-	-	-	-	-
Marine vessels and carriers	1	156	-	-	-	-	-	435	592
Total lease assets	13	178	-	3	4	1	33	752	984
Additions to exploration and evaluation:									
Exploration	-	-	-	1	-	26	-	18	45
Evaluation	-	-	-	-	255	-	39	16	310
Restoration	-	-	-	-	-	-	44	-	44
	-	-	-	1	255	26	83	34	399
Additions to oil and gas properties:									
Oil and gas properties	68	322	93	287	-	767	-	2	1,539
Capitalised borrowings costs[1]	1	17	2	10	-	27	-	-	57
Restoration	34	68	42	43	-	-	-	-	187
	103	407	137	340	-	794	-	2	1,783
Additions to lease assets:									
Land and buildings	12	6	-	3	-	-	1	2	24
Plant and equipment	-	-	-	-	-	-	-	-	-
Marine vessels and carriers	1	-	-	-	-	-	-	101	102
	13	6	-	3	-	-	1	103	126

1. Borrowing costs capitalised were at a weighted average interest rate of 3.8%.
2. The 2020 amounts have been restated to reflect the changes in the Development segment. Refer to Note A.1 for details.

B.2 Exploration and evaluation

	Oceania US$m	Asia US$m	Canada US$m	Africa US$m	Other US$m	Total US$m
Year ended 31 December 2021						
Carrying amount at 1 January 2021	**1,752**	**229**	**-**	**64**	**-**	**2,045**
Additions	**458**	**36**	**-**	**7**	**-**	**501**
Amortisation of licence acquisition costs	**-**	**-**	**-**	**(3)**	**-**	**(3)**
Expensed[1]	**-**	**(265)**	**-**	**-**	**-**	**(265)**
Transferred exploration and evaluation	**(1,664)**	**-**	**-**	**-**	**-**	**(1,664)**
Carrying amount at 31 December 2021	**546**	**-**	**-**	**68**	**-**	**614**
Year ended 31 December 2020						
Carrying amount at 1 January 2020	2,243	199	742	623	2	3,809
Additions	272	34	67	26	-	399
Amortisation of licence acquisition costs	(5)	(4)	-	(3)	-	(12)
Expensed[1]	-	-	-	-	(2)	(2)
Impairment losses[2]	(748)	-	(809)	-	-	(1,557)
Transferred exploration and evaluation	(10)	-	-	(582)	-	(592)
Carrying amount at 31 December 2020	1,752	229	-	64	-	2,045
Exploration commitments						
Year ended 31 December 2021	**8**	**8**	**-**	**77**	**1**	**94**
Year ended 31 December 2020	11	55	-	46	3	115

1. $56 million (2020: $2 million) relates to costs of unsuccessful wells. $209 million (2020: nil) relates to capitalised costs written off due to the Group's decision to withdraw from its interests in Myanmar.
2. Refer to Note B.4 for details on impairment.

Recognition and measurement

Expenditure on exploration and evaluation is accounted for in accordance with the area of interest method. The Group's application of the accounting policy is closely aligned to the US GAAP-based successful efforts method.

Areas of interest are based on a geographical area for which the rights of tenure are current. All exploration and evaluation expenditure, including general permit activity, geological and geophysical costs and new venture activity costs, is expensed as incurred except for the following:

- where the expenditure relates to an exploration discovery for which the assessment of the existence or otherwise of economically recoverable hydrocarbons is not yet complete; or
- where the expenditure is expected to be recouped through successful exploitation of the area of interest, or alternatively, by its sale.

The costs of acquiring interests in new exploration and evaluation licences are capitalised. The costs of drilling exploration wells are initially capitalised pending the results of the well.

Costs are expensed where the well does not result in the successful discovery of economically recoverable hydrocarbons and the recognition of an area of interest.

Subsequent to the recognition of an area of interest, all further evaluation costs relating to that area of interest are capitalised.

Upon approval for the commercial development of an area of interest, accumulated expenditure for the area of interest is transferred to oil and gas properties.

In the statement of cash flows, those cash flows associated with capitalised exploration and evaluation expenditure, including unsuccessful wells, are classified as cash flows used in investing activities.

Exploration commitments

The Group has exploration expenditure obligations which are contracted for, but not provided for in the financial statements. These obligations may be varied from time to time and are expected to be fulfilled in the normal course of the Group's operations.

Impairment

Refer to Note B.4 for details on impairment, including any write-offs.

Key estimates and judgements

(a) Area of interest

Typically, an area of interest (AOI) is defined by the Group as an individual geographical area whereby the presence of hydrocarbons is considered favourable or proved to exist. The Group has established criteria to recognise and maintain an AOI.

(b) Transfer to projects in development

Development activities commence after project sanctioning by the appropriate level of management. Judgement is applied by management in determining when the project is technically feasible and economically viable.

B.3 Oil and gas properties

	Land and buildings US$m	Transferred exploration and evaluation US$m	Plant and equipment US$m	Marine vessels and carriers US$m	Projects in development US$m	Total US$m
Year ended 31 December 2021						
Carrying amount at 1 January 2021	**749**	**431**	**11,933**	**11**	**2,143**	**15,267**
Additions	**-**	**-**	**13**	**-**	**2,268**	**2,281**
Disposals at written down value	**(2)**	**-**	**(2)**	**-**	**(19)**	**(23)**
Depreciation and amortisation	**(51)**	**(79)**	**(1,416)**	**(3)**	**-**	**(1,549)**
Impairment losses[1]	**(10)**	**-**	**-**	**-**	**-**	**(10)**
Impairment reversals[1]	**44**	**66**	**911**	**-**	**37**	**1,058**
Completions and transfers	**11**	**108**	**874**	**-**	**671**	**1,664**
Transfer to non-current assets held for sale[2]	**(2)**	**-**	**-**	**-**	**(252)**	**(254)**
Carrying amount at 31 December 2021	**739**	**526**	**12,313**	**8**	**4,848**	**18,434**
At 31 December 2021						
Historical cost	**1,701**	**1,495**	**32,241**	**184**	**5,250**	**40,871**
Accumulated depreciation and impairment	**(962)**	**(969)**	**(19,928)**	**(176)**	**(402)**	**(22,437)**
Net carrying amount	**739**	**526**	**12,313**	**8**	**4,848**	**18,434**
Year ended 31 December 2020						
Carrying amount at 1 January 2020	1,068	729	15,813	36	652	18,298
Additions	-	-	150	-	1,633	1,783
Disposals at written down value	-	-	(3)	-	(2)	(5)
Depreciation and amortisation	(55)	(99)	(1,533)	(2)	-	(1,689)
Impairment losses[1]	(264)	(199)	(2,636)	(23)	(590)	(3,712)
Completions and transfers	-	-	142	-	450	592
Carrying amount at 31 December 2020	749	431	11,933	11	2,143	15,267
At 31 December 2020						
Historical cost	1,722	1,348	31,225	184	2,791	37,270
Accumulated depreciation and impairment	(973)	(917)	(19,292)	(173)	(648)	(22,003)
Net carrying amount	749	431	11,933	11	2,143	15,267

1. Refer to Note B.4 for details on impairment losses and impairment reversals.
2. Refer to Note B.6 for details on non-current assets held for sale.

B.3 Oil and gas properties (cont.)

Recognition and measurement

Oil and gas properties are stated at cost less accumulated depreciation and impairment charges. Oil and gas properties include the costs to acquire, construct, install or complete production and infrastructure facilities such as pipelines and platforms, capitalised borrowing costs, transferred exploration and evaluation assets, development wells and the estimated cost of dismantling and restoration.

Subsequent capital costs, including major maintenance, are included in the asset's carrying amount only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be reliably measured.

Depreciation and amortisation

Oil and gas properties and other plant and equipment are depreciated to their estimated residual values at rates based on their expected useful lives.

Transferred exploration and evaluation and offshore plant and equipment are depreciated using the unit of production basis over proved plus probable reserves or proved reserves for late life assets. The depreciable amount for the unit of production basis excludes future development costs necessary to bring probable reserves into production. Onshore plant and equipment is depreciated using a straight-line basis over the lesser of useful life and the life of proved plus probable reserves. On a straight-line basis the assets have an estimated useful life of 5-50 years.

All other items of oil and gas properties are depreciated using the straight-line method over their useful life. They are depreciated as follows:

- Buildings – 24-40 years;
- Marine vessels and carriers – 10-40 years;
- Other plant and equipment – 5-15 years; and
- Land is not depreciated.

Impairment

Refer to Note B.4 for details on impairment.

Capital commitments

The Group has capital expenditure commitments contracted for, but not provided for in the financials statements, of $7,875 million (2020: $1,569 million) as at 31 December 2021. Subsequent to year end, capital commitments contracted for has reduced by approximately $2,876 million due to the Group's participating interest in the Pluto Train 2 Joint Venture reducing from 100% to 51% (refer to Note E.5).

Key estimates and judgements

(a) Reserves

The estimation of reserves requires significant management judgement and interpretation of complex geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries.

Estimates of oil and natural gas reserves are used to calculate depreciation and amortisation charges for the Group's oil and gas properties. Judgement is used in determining the reserve base applied to each asset. Typically, late life oil assets use proved reserves.

Estimates are reviewed at least annually or when there are changes in the economic circumstances impacting specific assets or asset groups. These changes may impact depreciation, asset carrying values, restoration provisions and deferred tax balances. If proved plus probable (2P) reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the asset's carrying value.

For more information regarding reserve assumptions, refer to the Reserves and resources statement on pages 55-59 of the Annual Report.

(b) Depreciation and amortisation

Judgement is required to determine when assets are available for use to commence depreciation and amortisation. Depreciation and amortisation generally commences on first production.

(c) Change in useful life

As a result of FID on the Scarborough Development and Pluto Train 2, the Group conducted a review of the expected utilisation of the Pluto LNG onshore assets. Pluto LNG onshore assets were previously intended for use until the cessation of production from Pluto LNG. A number of Pluto LNG onshore assets are now expected to be utilised in the processing of Scarborough reserves and as a result the expected useful lives of these assets have increased by a range of 1-23 years. The change in useful life has been applied prospectively from the month of FID and has resulted in a decrease in depreciation expense of $60 million for the year ended 31 December 2021.

B.4 Impairment of exploration and evaluation and oil and gas properties

Exploration and evaluation

Impairment testing

The recoverability of the carrying amount of exploration and evaluation assets is dependent on successful development and commercial exploitation, or alternatively, sale of the respective AOI.

Each AOI is reviewed half-yearly to determine whether economic quantities of hydrocarbons have been found or whether further exploration and evaluation work is underway or planned to support continued carry forward of capitalised costs. Where a potential impairment is indicated for an AOI, an assessment is performed using a fair value less costs to dispose (FVLCD) method to determine its recoverable amount. Upon approval for commercial development, exploration and evaluation assets are also assessed for impairment before they are transferred to oil and gas properties.

Impairment calculations

The recoverable amounts of exploration and evaluation assets are determined using FVLCD as there is no value in use (VIU). Costs to dispose are the incremental costs directly attributable to the disposal of an asset, excluding finance costs and income tax expense.

If the carrying amount of an AOI exceeds its recoverable amount, the AOI is written down to its recoverable amount and an impairment loss is recognised in the income statement.

For assets previously impaired, if the recoverable amount exceeds the carrying amount, the impairment is reversed, but only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been recognised if no impairment had occurred.

Oil and gas properties

Impairment testing

The carrying amounts of oil and gas properties are assessed half-yearly to determine whether there is an indication of impairment or impairment reversal for those assets which have previously been impaired. Indicators of impairment and impairment reversals include changes in future selling prices, future costs and reserves.

Oil and gas properties are assessed for impairment indicators and impairments on a cash-generating unit (CGU) basis. CGUs are determined as an FPSO and associated oil fields for an oil asset, and an LNG plant, offshore infrastructure and associated gas fields for a gas asset.

If there is an indicator of impairment or impairment reversal for a CGU then the recoverable amount is calculated.

Impairment calculations

The recoverable amount of an asset or CGU is determined as the higher of its VIU and FVLCD. VIU is determined by estimating future cash flows after taking into account the risks specific to the asset and discounting to present value using an appropriate discount rate.

If the carrying amount of an asset or CGU exceeds its recoverable amount, the asset or CGU is written down and an impairment loss is recognised in the income statement.

For assets previously impaired, if the recoverable amount exceeds the carrying amount, the impairment is reversed. The carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortisation, if no impairment had been recognised.

B.4 Impairment of exploration and evaluation and oil and gas properties (cont.)

Recognised impairment and impairment reversals

As at 31 December 2021, the Group identified the following indicators for impairment and impairment reversals:

- Pluto-Scarborough and Wheatstone CGU - a reduction of 2P total reserves within the Greater Pluto and Wheatstone reserves and resources estimates.
- Pluto-Scarborough CGU - additional value generated by Scarborough and Pluto Train 2, which have been combined with Pluto into a new Pluto-Scarborough CGU following the final investment decision for Scarborough and Pluto Train 2 in November 2021.
- North West Shelf CGU - updated cost and production profiles, including the impact of third-party processing agreements, and short-term pricing assumptions.
- NWS Oil (Okha) CGU - the reclassification to a late life oil asset due to natural reservoir decline and short-term pricing assumptions.

No impairment was recognised for Wheatstone and NWS Oil (Okha) as the recoverable amount exceeds the carrying amount of the CGU.

Impairment reversals were recognised for Pluto-Scarborough and NWS Gas (refer to Note A.1). The results were as follows:

			Impairment reversal				
			Oil and gas properties				
Segment	CGU	Recoverable amount US$m	Land and buildings US$m	Transferred exploration and evaluation US$m	Plant and equipment US$m	Projects in development US$m	Total US$m
Producing and Development	Pluto-Scarborough	17,474	42	53	563	24	682
Producing	North West Shelf	2,425	2	13	348	13	376
	Total	19,899	44	66	911	37	1,058

The recoverable amounts have been determined using the VIU method. The carrying amounts of the CGUs include all assets allocated to the CGU. Refer to key estimates and judgements for further details.

Sensitivity analysis

Changes in the following key assumptions have been estimated to result in a higher or lower carrying amounts[1] than what was determined as at 31 December 2021:

			Sensitivity (US$m)[2]					
			Discount rate: increase of 1%[3,4]	Discount rate: decrease of 1%	Brent price: increase of 10%	Brent price: decrease of 10%	FX: increase of 12%[5]	FX: decrease of 12%
Oil and gas properties	Producing and Development	Pluto-Scarborough	-	-	-	-	-	-
	Producing	North West Shelf	-	-	-	(13)	-	-
		Wheatstone	(159)	178	438	(438)	(122)	122
		NWS Oil (Okha)	(4)	4	39	(39)	(28)	28

1. Increases to carrying amounts are limited to historical impairment losses recognised, net of depreciation and amortisation that would have been incurred had no impairment taken place.
2. The sensitivities represent reasonable possible changes to the discount rate, oil price and FX assumptions.
3. A change of 1% represents 100 basis points.
4. The relationship between the discount rate and carrying amount is non-linear and as such, the sensitivities are unlikely to result in a symmetrical impact. Due to the non-linear relationship, the impact of changing the discount rate is likely to be greater at a lower discount rate than at a higher discount rate.
5. FX sensitivity of +12%/-12% was determined based on historical 5-year standard deviation of AU$/US$.

Impairment on non-current assets held for sale

The pending sale of a portion of the Wheatstone Construction Village resulted in an impairment loss of $10 million as the asset's carrying value exceeded its FVLCD, which was determined based on the underlying sale agreements, classified as Level 3 on the fair value hierarchy. An impairment loss of $10 million was recognised in the Wheatstone operating segment of Note A.1. Refer to Note B.6 for more details.

B.4 Impairment of exploration and evaluation and oil and gas properties (cont.)

Key estimates and judgements

CGU determination

Identification of a CGU requires management judgement. In determining the new combined Pluto-Scarborough CGU, management has determined that the Scarborough and Pluto Train 2 development concept integrates with the existing Pluto onshore assets and is the smallest group of assets that generate significant cash inflows that are independent from other assets or group of assets.

Recoverable amount calculation key assumptions

In determining the recoverable amount of CGUs, estimates are made regarding the present value of future cash flows when determining the VIU. These estimates require significant management judgement and are subject to risk and uncertainty, and hence changes in economic conditions can also affect the assumptions used and the rates used to discount future cash flow estimates.

The basis for each estimate used to determine recoverable amounts as at 31 December 2021 is set out below:

- Resource estimates – 2P reserves for oil and gas properties, except for NWS Oil (Okha) which is based on 1P reserves due to the reclassification to a late life asset. The reserves are as disclosed in the Reserves and resources statement in the 31 December 2021 Annual Report on pages 55-59.
- Inflation rate – an inflation rate of 2.0% has been applied.
- Foreign exchange rates – a rate of $0.75 US$:AU$ is based on management's view of long-term exchange rates.
- Discount rates – a range of pre-tax discount rates between 8.9% and 11.6% (post-tax discount rate 7.5%-8.5%) for CGUs has been applied. The discount rate reflects an assessment of the risks specific to the asset.
- An evaluation of climate risk is reflected in Woodside's assumptions on carbon cost pricing, including a long-term Australian carbon price of US$80/tonne of emissions (real terms 2022). This is applicable to Australian emissions that exceed facility-specific baselines in accordance with Australian regulations, as well as global emissions that exceed voluntary corporate net emissions targets. Woodside continues to monitor the uncertainty around climate change risks and will revise carbon pricing assumptions accordingly.
- LNG price – the majority of LNG sales contracts are linked to an oil price marker; accordingly the LNG prices used are consistent with oil price assumptions.
- Brent oil prices – derived from long-term views of global supply and demand, building upon past experience of the industry and consistent with external sources. Prices are adjusted for premiums and discounts based on the nature and quality of the product. Brent oil price estimates have considered the risk of climate policies along with other factors such as industry investment and cost trends. There is significant uncertainty around how society will respond to the climate challenge; Woodside's pricing assumptions reflect a 'most-likely' scenario in which global governments pursue decarbonisation as well as other goals such as energy security and economic development. As with carbon pricing, Woodside continues to monitor this uncertainty and will revise its oil pricing assumptions accordingly in its transition to a lower carbon economy. Further information on climate change risk is provided in Woodside's Climate Report 2021. The nominal Brent oil prices (US$/bbl) used were:

	2022	2023	2024	2025	2026	2027
31 December 2021[1]	**73**	**71**	**68**	**69**	**70**	**72**
30 June 2020[2]	57	62	67	72	73	75

1. Based on US$65/bbl (2022 real terms) from 2024 with prices escalated at 2.0% annually thereafter.
2. Based on US$65/bbl (2020 real terms) from 2025 with prices escalated at 2.0% annually thereafter.

B.4 Impairment of exploration and evaluation and oil and gas properties (cont.)

Recognised impairment and impairment reversals (cont.)

For the year ended 31 December 2020

As at 30 June 2020 the Group assessed each AOI and CGU and identified the following indicators of impairment for certain AOIs and all CGUs:

- AOIs – uncertainties on fiscal conditions and/or development strategies have led to a lack of substantive ongoing and/or planned activity; and
- CGUs – the decrease in global oil and gas prices due to the impacts of the COVID-19 pandemic, oversupply and weakened global demand.

Impairment losses before tax were recognised in profit and loss, refer to Note A.1. The results were as follows, which include the AOIs and CGUs which were subject to impairment testing:

			Impairment losses							
				Oil and gas properties						
Segment	AOI/CGU	Recoverable amount[1] US$m	Exploration and evaluation US$m	Land and buildings US$m	Transferred exploration and evaluation US$m	Plant and equipment US$m	Marine vessels and carriers US$m	Projects in development US$m	Total US$m
Producing	Pluto (WA-404-P)[2,4]	-	429	-	-	-	-	-	-
Development	Kitimat LNG[5]	-	809	-	-	-	-	-	-
	Sunrise[6]	-	168	-	-	-	-	-	-
Other segments	Toro (WA-93-R)/ Ragnar (WA-94-R)[3,7]	-	151	-	-	-	-	-	-
Producing	North West Shelf	1,922	-	2	15	387	23	27	454
	Pluto	9,712	-	54	59	666	-	83	862
	Australia Oil								
	Vincent (Ngujima-Yin)	836	-	-	64	517	-	26	607
	NWS Oil (Okha)	102	-	-	3	61	-	3	67
	Wheatstone	3,029	-	208	58	1,005	-	130	1,401
Development	Sangomar	415	-	-	-	-	-	321	321
	Total	16,016	1,557	264	199	2,636	23	590	3,712

1. The recoverable amounts for exploration and evaluation assets and oil and gas properties were determined using the FVLCD and VIU methods, respectively. The carrying amount of the CGUs include all assets allocated to the CGU. Refer to key estimates and judgements for further details.
2. The impairment of Pluto (WA-404-P) has resulted in a reclassification of the Greater Pluto (WA-404-P) Proved (1P) Undeveloped Reserves of 91 MMboe and Proved plus Probable (2P) Undeveloped Reserves of 123 MMboe, to Best Estimate (2C) Contingent Resources.
3. Converted from WA-430-P.

Impairment indicators for exploration and evaluation assets:

4. Increased uncertainty of development timing, given the prioritisation of the higher-value Scarborough resource.
5. The revision of long-term oil and Alberta natural gas market spot price assumptions, and a change to the development concept to a standalone LNG facility, de-linked from the upstream resource, with different accounting requirements.
6. Increased uncertainty of regulatory conditions, fiscal terms and development concept.
7. Increased uncertainty of development timing.

B.4 Impairment of exploration and evaluation and oil and gas properties (cont.)

Following the impairment recognised at 30 June 2020, the Group assessed each AOI and CGU for indicators of impairment as at 31 December 2020 in accordance with the Group's accounting policy. In assessing whether there was an indicator of impairment or impairment reversal, the Group considered whether there were any significant changes in the key estimates and judgements and underlying project assumptions used for the 30 June 2020 impairment assessment and determined that there were none. No indicators of additional impairment or impairment reversal were identified as at 31 December 2020.

Key estimates and judgements

Recoverable amount calculation key assumptions

In determining the recoverable amounts of exploration and evaluation assets, the market comparison approach using adjusted market multiples (fair value hierarchy Level 3) was utilised to determine FVLCD.

In determining the recoverable amount of CGUs, estimates are made regarding the present value of future cash flows when determining the VIU. These estimates require significant management judgement and are subject to risk and uncertainty, and hence changes in economic conditions can also affect the assumptions used and the rates used to discount future cash flow estimates.

The basis for the estimates used to determine recoverable amounts as at 30 June 2020 is set out below:

- Resource estimates – 2P reserves for oil and gas properties as disclosed in the Reserves and resources statement in the 31 December 2019 Annual Report on pages 44 to 47.
- Inflation rate – an inflation rate of 2.0% has been applied.
- Foreign exchange rates – a rate of $0.75 US$:AU$ is based on management's view of long-term exchange rates.
- Discount rates – a range of pre-tax discount rates between 9.3% and 14.8% (post-tax discount rates 7.5% and 11.0%) for CGUs has been applied. The discount rate reflects an assessment of the risks specific to the asset, including country risk.
- An evaluation of climate risk impacts, including a long-term Australian carbon price of US$80/tonne (real terms 2020), applicable to Australian emissions that exceed facility-specific baselines in accordance with Australian regulations.
- LNG price – the majority of LNG sales contracts are linked to an oil price marker; accordingly the LNG prices used are consistent with oil price assumptions.
- Brent oil prices – derived from long-term views of global supply and demand, building upon past experience of the industry and consistent with external sources. Prices are adjusted for premiums and discounts based on the nature and quality of the product. The nominal Brent oil prices (US$/bbl) used were:

	2020	2021	2022	2023	2024	2025
30 June 2020	35	45	57	62	67	72[1]

1. Based on US$65/bbl (2020 real terms) from 2025 and prices are escalated at 2.0% onwards (31 December 2019: US$72.5/bbl (2020 real terms) and prices are escalated at 2.0% onwards).

B.5 Significant production and growth asset acquisitions

a) Sangomar - Acquisition from FAR Senegal RSSD SA

On 7 July 2021, Woodside completed the acquisition of FAR Senegal RSSD SA's interest in the RSSD Joint Venture (13.67% interest in the Sangomar exploitation area and 15% interest in the remaining RSSD evaluation area), for an aggregate purchase price of $212 million. The transaction was accounted for as an asset acquisition.

Additional payments of up to $55 million are contingent on future commodity prices and timing of first oil. The contingent payments terminate on the earliest of 31 December 2027, three years from first oil being sold, and a total contingent payment of $55 million being reached. The contingent payments are accounted for as contingent liabilities in accordance with the Group's accounting policies.

Woodside's interest has increased to 82% in the Sangomar exploitation area (31 December 2020: 68.33%) and to 90% in the remaining RSSD evaluation area (31 December 2020: 75%).

Assets acquired and liabilities assumed

The identifiable assets and liabilities acquired as at the date of the acquisition inclusive of transaction costs are:

	US$m
Oil and gas properties	205
Exploration and evaluation	7
Cash acquired	3
Payables	(13)
Net other assets and liabilities assumed	10
Total identifiable net assets at acquisition	**212**

Cash flows on acquisition

	US$m
Purchase cash consideration	212
Transaction costs	-
Total purchase consideration	212
Net cash outflows on acquisition	**212**

Key estimates and judgements

Nature of acquisition

Judgement is required to determine if the transaction is the acquisition of an asset or a business combination. The Sangomar project is in the early phase of development and a substantive process that has the ability to convert inputs to outputs is not present and therefore the acquisitions in both 2020 and 2021 are treated as asset acquisitions.

b) BHP merger commitment deed

On 17 August 2021, Woodside and BHP Group (BHP) entered into a merger commitment deed to combine their respective oil and gas portfolios by an all stock merger (the Transaction). The share sale agreement and the integration and transition services agreement were executed on 22 November 2021.

On completion of the Transaction, BHP's oil and gas business will merge with Woodside, and Woodside will issue new shares to be distributed to BHP shareholders. The expanded Woodside will be owned 52% by existing Woodside shareholders and 48% by existing BHP shareholders. The Transaction is subject to satisfaction of conditions precedent including shareholder, regulatory and other approvals. The completion of the proposed merger is targeted for Q2 2022 following all necessary approvals.

Woodside and BHP have also agreed on an option for BHP to sell its 26.5% interest in the Scarborough Joint Venture and its 50% interest in the Thebe and Jupiter Joint Ventures to Woodside. The option is exercisable by BHP in the second half of 2022 and, if exercised, consideration of $1,000 million is payable to BHP plus working capital adjustments from 1 July 2021 to completion date. An additional $100 million is payable contingent upon future FID for a Thebe development.

c) Sangomar - Acquisition from Capricorn Senegal Limited

On 22 December 2020, Woodside completed the acquisition of Capricorn Senegal Limited's (Cairn's) interest in the RSSD Joint Venture (36.44% interest in the Sangomar exploitation area and 40% interest in the remaining RSSD evaluation area) for an aggregate purchase price of $527 million. The transaction was accounted for as an asset acquisition.

Additional payments of up to $100 million are contingent on future commodity prices and the timing of first oil. The contingent payments are accounted for as contingent liabilities in accordance with the Group's accounting policies.

Assets acquired and liabilities assumed

The identifiable assets and liabilities acquired as at the date of the acquisition inclusive of transaction costs were:

	US$m
Oil and gas properties	540
Exploration and evaluation	26
Cash acquired	5
Payables	(51)
Net other assets and liabilities assumed	7
Total identifiable net assets at acquisition	**527**

Cash flows on acquisition

	US$m
Purchase cash consideration	525
Transaction costs	2
Total purchase consideration	527
Net cash outflows on acquisition	**527**

B.6 Non-current assets held for sale

Recognition and measurement

The Group classifies non-current assets and liabilities as held for sale if their carrying amounts will be recovered principally through sale rather than through continuing use. Such non-current assets and liabilities classified as held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Costs to sell are the incremental costs directly attributable to the sale, excluding the finance costs and income tax expense.

The criteria for held for sale classification is regarded as met only when the sale is highly probable and the asset is available for sale in its present condition. Actions required to complete the sale should indicate that it is unlikely that significant changes to the sale will be made or that the decision to sell will be withdrawn. Management must be committed to the sale, expected within one year from the date of the classification.

Property, plant and equipment and intangible assets are not depreciated or amortised once classified as held for sale. Assets and liabilities classified as held for sale are presented separately as current items in the statement of financial position.

Transfers to non-current assets held for sale

On 15 November 2021, the Group and Global Infrastructure Partners (GIP) entered into a Sale and Purchase Agreement for GIP to acquire a 49% participating interest in the Pluto Train 2 Joint Venture. The transaction completed on 18 January 2022 (refer to Note E.5), reducing the Group's participating interest from 100% to 51%. Accordingly, the associated Pluto Train 2 assets within the Development segment have been reclassified to non-current assets held for sale. The arrangements require GIP to fund its 49% share of capital expenditure from 1 October 2021 and an additional amount of capital expenditure of approximately $822 million. If the total capital expenditure incurred is less than $5,600 million, GIP will pay Woodside an additional amount equal to 49% of the under-spend. In the event of a cost overrun, Woodside will fund up to approximately $822 million of GIP's share of the overrun. Delays to the expected start-up of production will result in payments by Woodside to GIP in certain circumstances. The arrangements include provisions for GIP to be compensated for exposure to additional Scope 1 emissions liabilities above agreed baselines, and to sell its 49% interest back to Woodside if the status of key regulatory approvals materially changes.

In addition, in December 2021, Woodside committed to sell a portion of the Wheatstone Construction Village and six residential properties. The construction village within the Wheatstone operating segment and the residential properties within the Pluto segment have been reclassified as non-current assets held for sale and both sale transactions are expected to complete in 2022.

Impairment relating to the non-current assets held for sale

Immediately before the classification as non-current assets held for sale, the recoverable amount of the relevant assets were calculated and an impairment of the Wheatstone Construction Village amounting to $10 million was recognised within oil and gas properties (refer to Note B.4).

Assets and liabilities of the non-current assets held for sale

As at 31 December 2021, the Group has reclassified $252 million of Pluto Train 2 assets, $1 million of the Wheatstone Construction Village assets and $1 million of the Pluto residential housing to non-current assets held for sale. There are no recognised liabilities associated with the non-current assets held for sale.

In this section

This section addresses cash, debt and the capital position of the Group at the end of the reporting period including, where applicable, the accounting policies applied and the key estimates and judgements made.

Key financial and capital risks in this section

Capital risk management

Group Treasury is responsible for the Group's capital management including cash, debt and equity. Capital management is undertaken to ensure that a secure, cost-effective and flexible supply of funds is available to meet the Group's operating and capital expenditure requirements. A stable capital base is maintained from which the Group can pursue its growth aspirations, whilst maintaining a flexible capital structure that allows access to a range of debt and equity markets to both draw upon and repay capital.

The Dividend Reinvestment Plan (DRP) was approved by shareholders at the Annual General Meeting in 2003 for activation as required to fund future growth. The DRP was reactivated for the 2019 interim dividend and will remain in place until further notice.

A range of financial metrics are monitored, including gearing and cash flow leverage, and Treasury policy breaches and exceptions.

Liquidity risk management

Liquidity risk arises from the financial liabilities of the Group and the Group's subsequent ability to meet its obligations to repay financial liabilities as and when they fall due. The liquidity position of the Group is managed to ensure sufficient liquid funds are available to meet its financial commitments in a timely and cost-effective manner.

The Group's liquidity is continually reviewed, including cash flow forecasts to determine the forecast liquidity position and maintain appropriate liquidity levels. At 31 December 2021, the Group had a total of $6,125 million (2020: $6,704 million) of available undrawn facilities and cash at its disposal. The maturity profile of interest-bearing liabilities is disclosed in Note C.2, trade and other payables are disclosed in Note D.4 and lease liabilities are disclosed in Note D.7. Financing facilities available to the Group are disclosed in Note C.2.

Interest rate risk management

Interest rate risk is the risk that the Group's financial position will fluctuate due to changes in market interest rates.

The Group's exposure to the risk of changes in market interest rates relates primarily to financial instruments with floating interest rates including long-term debt obligations, cash and short-term deposits. The Group manages its interest rate risk by maintaining an appropriate mix of fixed and floating rate debt. To manage the ratio of fixed rate debt to floating rate debt, the Group may enter into interest rate swaps. The Group holds cross-currency interest rate swaps to hedge the foreign exchange risk (refer to Section A) and interest rate risk of the CHF denominated medium term note. The Group also holds interest rate swaps to hedge the interest rate risk associated with the $600 million syndicated facility. Refer to Notes C.2 and D.6 for further details.

At the reporting date, the Group was exposed to various benchmark interest rates that were not designated in cash flow hedges, primarily through $2,962 million (2020: $3,527 million) on cash and cash equivalents, $367 million (2020: $450 million) on interest-bearing liabilities (excluding transaction costs) and $9 million (2020: $15 million) on cross-currency interest rate swaps.

A reasonably possible change in the USD London Interbank Offered Rate (LIBOR) (+1.0%/-1.0% (2020: +0.5%/-0.5%)), with all variables held constant, would not have a material impact on the Group's equity or the income statement in the current period.

The Group's Treasury function is closely monitoring the market and the output from the various industry working groups managing the transition to new benchmark interest rates. The Treasury function is assessing the implications of the Interbank Offered Rates (IBOR) reform across the Group and will manage and execute the transition from current benchmark rates to alternative benchmark rates.

C.1 Cash and cash equivalents

	2021 US$m	2020 US$m
Cash and cash equivalents		
Cash at bank	300	367
Term deposits	2,725	3,237
Total cash and cash equivalents	3,025	3,604

Recognition and measurement

Cash and cash equivalents in the statement of financial position comprise cash at bank and short-term deposits with an original maturity of three months or less. Cash and cash equivalents are stated at face value in the statement of financial position.

Foreign exchange risk

The Group held $108 million of cash and cash equivalents at 31 December 2021 (2020: $78 million) in currencies other than US dollars.

C.2 Interest-bearing liabilities and financing facilities

	Bilateral Facilities US$m	Syndicated Facilities US$m	JBIC Facility US$m	US Bonds US$m	Medium Term Notes US$m	Total US$m
Year ended 31 December 2021						
At 1 January 2021	(4)	593	250	4,778	597	6,214
Repayments[1]	-	-	(84)	(700)	-	(784)
Fair value adjustment and foreign exchange movement	-	-	-	-	(5)	(5)
Transaction costs capitalised and amortised	-	2	-	3	-	5
Carrying amount at 31 December 2021	(4)	595	166	4,081	592	5,430
Current	(2)	(2)	83	(2)	200	277
Non-current	(2)	597	83	4,083	392	5,153
Carrying amount at 31 December 2021	(4)	595	166	4,081	592	5,430
Undrawn balance at 31 December 2021	1,900	1,200	-	-	-	3,100
Year ended 31 December 2020						
At 1 January 2020	(3)	(4)	333	4,775	578	5,679
Repayments[1]	-	-	(83)	-	-	(83)
Drawdowns[1]	-	600	-	-	-	600
Fair value adjustment and foreign exchange movement	-	-	-	-	19	19
Transaction costs capitalised and amortised	(1)	(3)	-	3	-	(1)
Carrying amount at 31 December 2020	(4)	593	250	4,778	597	6,214
Current	(1)	(2)	83	696	-	776
Non-current	(3)	595	167	4,082	597	5,438
Carrying amount at 31 December 2020	(4)	593	250	4,778	597	6,214
Undrawn balance at 31 December 2020	1,900	1,200	-	-	-	3,100

1. Included in cash flows classified within financing activities in the statement of cash flows.

Recognition and measurement

All borrowings are initially recognised at fair value less transaction costs. Borrowings are subsequently carried at amortised cost. Any difference between the proceeds received and the redemption amount is recognised in the income statement over the period of the borrowings using the effective interest method.

Borrowings designated as a hedged item are measured at amortised cost adjusted to record changes in the fair value of risks that are being hedged in fair value hedges. The changes in the fair value risks of the hedged item resulted in a gain of $5 million being recorded (2020: loss of $19 million), and a loss of $7 million recorded on the hedging instrument (2020: gain of $18 million).

All bonds, notes and facilities are subject to various covenants and negative pledges restricting future secured borrowings, subject to a number of permitted lien exceptions. Neither the covenants nor the negative pledges have been breached at any time during the reporting period.

Fair value

The carrying amount of interest-bearing liabilities approximates their fair value, with the exception of the Group's unsecured bonds and the medium term notes. The unsecured bonds have a carrying amount of $4,081 million (2020: $4,778 million) and a fair value of $4,443 million (2020: $5,196 million). The medium term notes have a carrying amount of $592 million (2020: $597 million) and a fair value of $604 million (2020: $617 million). Fair value is calculated based on the present value of future principal and interest cash flows, discounted at the market rate of interest at the reporting date and classified as Level 1 on the fair value hierarchy. Where these cash flows are in a foreign currency, the present value is converted to US dollars at the foreign exchange spot rate prevailing at the reporting date. The Group's repayment obligations remain unchanged.

Foreign exchange risk

All interest-bearing liabilities are denominated in US dollars, excluding the CHF175 million medium term note.

C.2 Interest-bearing liabilities and financing facilities (cont.)

Maturity profile of interest-bearing liabilities

The table below presents the contractual undiscounted cash flows associated with the Group's interest-bearing liabilities, representing principal and interest. The figures will not necessarily reconcile with the amounts disclosed in the consolidated statement of financial position.

	2021 US$m	2020 US$m
Due for payment in:		
1 year or less	**470**	979
1-2 years	**462**	470
2-3 years	**188**	462
3-4 years	**1,169**	178
4-5 years	**951**	1,161
More than 5 years	**3,320**	4,266
	6,560	7,516

Amounts exclude transaction costs.

Bilateral facilities

The Group has 14 bilateral loan facilities totalling $1,900 million (2020: 14 bilateral loan facilities totalling $1,900 million). Details of bilateral loan facilities at the reporting date are as follows:

Number of facilities	Term (years)	Currency	Extension option
5	5	US$	Evergreen
2	4	US$	Evergreen
7	3	US$	Evergreen

Interest rates are based on USD LIBOR and margins are fixed at the commencement of the drawdown period. Interest is paid at the end of the drawdown period. Evergreen facilities may be extended continually by a year subject to the bank's agreement.

Syndicated facility

On 14 October 2019, Woodside increased the existing facility to $1,200 million, with $400 million expiring on 11 October 2022 and $800 million expiring on 11 October 2024. Interest rates are based on USD LIBOR and margins are fixed at the commencement of the drawdown period.

On 17 January 2020, the Group completed a new $600 million syndicated facility with a term of seven years. Interest is based on the USD London Interbank Offered Rate (LIBOR) plus 1.2%. Interest is paid on a quarterly basis.

Japan Bank for International Cooperation (JBIC) facility

On 24 June 2008, the Group entered into a two tranche committed loan facility of $1,000 million and $500 million respectively. The $500 million tranche was repaid in 2013. There is a prepayment option for the remaining balance. Interest rates are based on LIBOR. Interest is payable semi-annually in arrears and the principal amortises on a straight-line basis, with equal instalments of principal due on each interest payment date (every six months).

Under this facility, 90% of the receivables from designated Pluto LNG sale and purchase agreements are secured in favour of the lenders through a trust structure, with a required reserve amount of $30 million.

To the extent that this reserve amount remains fully funded and no default notice or acceleration notice has been given, the revenue from Pluto LNG continues to flow directly to the Group from the trust account.

Medium term notes

On 28 August 2015, the Group established a $3,000 million Global Medium Term Notes Programme listed on the Singapore Stock Exchange. Three notes have been issued under this programme as set out below:

Maturity date	Currency	Carrying amount (million)	Nominal interest rate
15 July 2022	US$	200	Floating three month US$ LIBOR
11 December 2023	CHF	175	1%
29 January 2027	US$	200	3%

The unutilised program is not considered to be an unused facility.

US bonds

The Group has four unsecured bonds issued in the United States of America as defined in Rule 144A of the *US Securities Act of 1933* as set out below:

Maturity date	Carrying amount US$m	Nominal interest rate
5 March 2025	1,000	3.65%
15 September 2026	800	3.70%
15 March 2028	800	3.70%
4 March 2029	1,500	4.50%

Interest on the bonds is payable semi-annually in arrears.

During the period, the Group redeemed the $700 million 2021 US bond and repaid $84 million on the JBIC facility.

C.3 Contributed equity

Recognition and measurement

Issued capital

Ordinary shares are classified as equity and recorded at the value of consideration received. The cost of issuing shares is shown in share capital as a deduction, net of tax, from the proceeds.

Reserved shares

The Group's own equity instruments, which are reacquired for later use in employee share-based payment arrangements (reserved shares), are deducted from equity. No gain or loss is recognised in the income statement on the purchase, sale, issue or cancellation of the Group's own equity instruments.

(a) Issued and fully paid shares

	Number of shares	US$m
Year ended 31 December 2021		
Opening balance	**962,225,814**	**9,297**
DRP - ordinary shares issued at A$24.77 (2020 final dividend)	**1,354,072**	**26**
DRP - ordinary shares issued at A$19.47 (2021 interim dividend)	**6,051,940**	**86**
Amounts as at 31 December 2021	**969,631,826**	**9,409**
Year ended 31 December 2020		
Opening balance	942,286,900	9,010
DRP - ordinary shares issued at A$25.61 (2019 final dividend)	12,072,034	181
DRP - ordinary shares issued at A$18.79 (2020 interim dividend)	6,091,035	83
Employee share plan - ordinary shares issued at A$18.27 (2017 Woodside equity plan)	1,775,845	23
Amounts as at 31 December 2020	962,225,814	9,297

All shares are a single class with equal rights to dividends, capital, distributions and voting. The Company does not have authorised capital nor par value in relation to its issued shares.

(b) Shares reserved for employee share plans

	Number of shares	US$m
Year ended 31 December 2021		
Opening balance	**1,766,099**	**(23)**
Purchases during the year	**2,683,469**	**(47)**
Vested during the year	**(2,629,824)**	**40**
Amounts at 31 December 2021	**1,819,744**	**(30)**
Year ended 31 December 2020		
Opening balance	1,985,306	(39)
Purchases during the year	2,242,345	(32)
Vested during the year	(2,461,552)	48
Amounts at 31 December 2020	1,766,099	(23)

C.4 Other reserves

	2021 US$m	2020 US$m
Other reserves		
Employee benefits reserve	**232**	219
Foreign currency translation reserve	**793**	793
Hedging reserve	**(400)**	(71)
Distributable profits reserve	**58**	462
	683	1,403

Nature and purpose

Employee benefits reserve

Used to record share-based payments associated with the employee share plans and remeasurement adjustments relating to the defined benefit plan.

Foreign currency translation reserve

Used to record foreign exchange differences arising from the translation of the financial statements of foreign entities from their functional currency to the Group's presentation currency.

Hedging reserve

Used to record gains and losses on hedges designated as cash flow hedges, and foreign currency basis spread arising from the designation of a financial instrument as a hedging instrument. Gains and losses accumulated in the cash flow hedge reserve are taken to the income statement in the same period during which the hedged expected cash flows affect the income statement.

Distributable profits reserve

Used to record distributable profits generated by the Parent entity, Woodside Petroleum Ltd.

In this section

This section addresses the other assets and liabilities position at the end of the reporting period including, where applicable, the accounting policies applied and the key estimates and judgements made.

Key financial and capital risks in this section

Credit risk management

Credit risk is the risk that a counterparty will not meet its obligation under a financial instrument or customer contract, leading to a financial loss to the Group. Credit risk arises from the financial assets of the Group, which comprise trade and other receivables, loans receivables and deposits with banks and financial institutions.

The Group manages its credit risk on trade receivables and financial instruments by predominantly dealing with counterparties with an investment grade credit rating. Sufficient collateral is obtained to mitigate the risk of financial loss when transacting with counterparties with below investment grade credit ratings. Customers who wish to trade on unsecured credit terms are subject to credit verification procedures. Receivable balances are monitored on an ongoing basis. As a result, the Group's exposure to bad debts is not significant. The Group's maximum credit risk is limited to the carrying amount of its financial assets.

Customer credit risk is managed by the Treasury function subject to the Group's established policy, procedures and controls relating to customer credit risk management. Credit quality of a customer is assessed based on an extensive credit rating scorecard and individual credit limits are defined in accordance with this assessment. Outstanding customer receivables are regularly monitored. At 31 December 2021, the Group had four customers (2020: four customers) that owed the Group more than $10 million each and accounted for approximately 88% (2020: 82%) of all trade receivables. Payment terms are typically 14 to 30 days providing only a short credit exposure.

The Group considers the probability of default upon initial recognition of the asset and whether there has been a significant depreciation in credit quality on an ongoing basis. A significant decrease in credit quality is defined as a debtor being greater than 30 days past due in making a contractual payment. Credit losses for trade receivables (including lease receivables) and contract assets are determined by applying the simplified approach and are measured at an amount equal to lifetime expected loss. Under the simplified approach, determination of the loss allowance provision and expected loss rate incorporates past experience and forward-looking information, including the outlook for market demand and forward-looking interest rates. A default on other financial assets is considered to be when the counterparty fails to make contractual payments within 60 days of when they fall due.

At 31 December 2021, the Group had a provision for credit losses of nil (2020: nil). Subsequent to 31 December 2021, 100% (2020: 100%) of the trade receivables balance of $152 million (2020: $164 million) has been received.

Credit risk from balances with banks is managed by the Treasury function in accordance with the Group's policy. The Group's main funds are placed as short-term deposits with reputable financial institutions with strong investment grade credit ratings. At 31 December 2021 and 31 December 2020, there were no significant concentrations of credit risk within the Group and financial instruments are spread amongst a number of financial institutions to minimise the risk of counterparty default. The maximum exposure to financial institution credit risk is represented by the sum of all cash deposits plus accrued interest, bank account balances and fair value of derivative assets. The Group's counterparty credit policy limits this exposure to commercial and investment banks, according to approved credit limits based on the counterparty's credit rating.

D.1 Segment assets and liabilities

	2021 US$m	2020 US$m
(a) Segment assets		
NWS	**2,208**	1,943
Pluto	**9,380**	9,250
Australia Oil	**758**	978
Wheatstone	**3,047**	3,108
Scarborough	**2,281**	1,294
Sangomar	**2,872**	1,254
Other development	**482**	507
Other segments	**411**	697
Unallocated items	**5,035**	5,592
	26,474	24,623

	2021 US$m	2020 US$m
(b) Segment liabilities		
NWS	**647**	679
Pluto	**937**	950
Australia Oil	**913**	848
Wheatstone	**302**	281
Scarborough	**84**	16
Sangomar	**350**	96
Other development	**83**	153
Other segments	**798**	953
Unallocated items	**8,131**	7,772
	12,245	11,748

Refer to Note A.1 for descriptions of the Group's segments. Unallocated assets mainly comprise cash and cash equivalents, deferred tax assets and lease assets. Unallocated liabilities mainly comprise interest-bearing liabilities, deferred tax liabilities and lease liabilities.

D.2 Receivables

	2021 US$m	2020 US$m
(a) Receivables (current)		
Trade receivables[1]	**152**	164
Other receivables[1]	**123**	75
Loans receivable	**75**	59
Lease receivables	**18**	3
Interest receivable	**-**	1
Dividend receivable	**-**	1
	368	303
(b) Receivables (non-current)		
Loans receivable	**627**	394
Lease receivables	**26**	10
Defined benefit plan asset	**33**	19
	686	423

1. Interest-free and settlement terms are usually between 14 and 30 days.

Recognition and measurement

Trade receivables are initially recognised at the transaction price determined under AASB 15 *Revenue from Contracts with Customers*. Other receivables are initially recognised at fair value. Receivables that satisfy the contractual cash flow and business model tests are subsequently measured at amortised cost less an allowance for uncollectable amounts. Uncollectable amounts are determined using the expected loss impairment model. Collectability and impairment are assessed on a regular basis.

Subsequent recoveries of amounts previously written off are credited against other expenses in the income statement. Certain receivables that do not satisfy the contractual cash flow and business model tests are subsequently measured at fair value (refer to Note D.6).

The Group's customers are required to pay in accordance with agreed payment terms. Depending on the product, settlement terms are 14 to 30 days from the date of invoice or bill of lading and customers regularly pay on time. There are no significant overdue trade receivables as at the end of the reporting period (2020: nil).

Fair value

The carrying amount of trade and other receivables approximates their fair value.

Foreign exchange risk

The Group held $121 million of receivables at 31 December 2021 (2020: $68 million) in currencies other than US dollars (predominantly Australian dollars).

Loans receivable

On 9 January 2020, Woodside Energy Finance (UK) Ltd entered into a secured loan agreement with Petrosen (the Senegal National Oil Company), to provide up to $450 million for the purpose of funding Sangomar project costs. The facility has a maximum term of 12 years and semi-annual repayments of the loan are due to commence at the earlier of 12 months after RFSU or 30 June 2025. The carrying amount of the loan receivable is $335 million at 31 December 2021 (2020: $113 million), which approximates its fair value. The remaining balance of loans receivable is due from non-controlling interests.

D.3 Inventories

	2021 US$m	2020 US$m
(a) Inventories (current)		
Petroleum products		
Goods in transit	**35**	18
Finished stocks	**34**	33
Warehouse stores and materials	**133**	74
	202	125
(b) Inventories (non-current)		
Warehouse stores and materials	**19**	40
	19	40

Recognition and measurement

Inventories include hydrocarbon stocks, consumable supplies and maintenance spares. Inventories are valued at the lower of cost and net realisable value. Cost is determined on a weighted average basis and includes direct costs and an appropriate portion of fixed and variable production overheads where applicable. Inventories determined to be obsolete or damaged are written down to net realisable value, being the estimated selling price less selling costs.

D.4 Payables

The following table shows the Group's payables balances and maturity analysis.

	< 30 days US$m	30-60 days US$m	> 60 days US$m	Total US$m
Year ended 31 December 2021				
Trade payables[1]	**191**	**-**	**-**	**191**
Other payables[1]	**390**	**-**	**-**	**390**
Interest payable[2]	**7**	**-**	**51**	**58**
Total payables	**588**	**-**	**51**	**639**
Year ended 31 December 2020				
Trade payables[1]	100	-	-	100
Other payables[1]	342	-	-	342
Interest payable[2]	7	5	51	63
Total payables	449	5	51	505

1. Interest-free and normally settled on 30 day terms.
2. Details regarding interest-bearing liabilities are contained in Note C.2.

Recognition and measurement

Trade and other payables are carried at amortised cost and are recognised when goods and services are received, whether or not billed to the Group, prior to the end of the reporting period.

Fair value

The carrying amount of payables approximates their fair value.

Foreign exchange risk

The Group held $311 million of payables at 31 December 2021 (2020: $210 million) in currencies other than US dollars (predominantly Australian dollars).

D.5 Provisions

	Restoration[1] US$m	Employee benefits US$m	Onerous contracts[2] US$m	Other US$m	Total US$m
Year ended 31 December 2021					
At 1 January 2021	**2,134**	**295**	**349**	**129**	**2,907**
Change in provision	**60**	**(9)**	**(140)**	**(23)**	**(112)**
Unwinding of present value discount	**24**	**-**	**5**	**-**	**29**
Carrying amount at 31 December 2021	**2,218**	**286**	**214**	**106**	**2,824**
Current	**235**	**269**	**-**	**101**	**605**
Non-current	**1,983**	**17**	**214**	**5**	**2,219**
Net carrying amount	**2,218**	**286**	**214**	**106**	**2,824**
Year ended 31 December 2020					
At 1 January 2020	1,869	189	-	70	2,128
Change in provision	237	106	347	59	749
Unwinding of present value discount	28	-	2	-	30
Carrying amount at 31 December 2020	2,134	295	349	129	2,907
Current	54	272	46	128	500
Non-current	2,080	23	303	1	2,407
Net carrying amount	2,134	295	349	129	2,907

1. 2021 change in provision is due to changes in estimates of $239 million (primarily due to the inclusion of costs for the removal of rigid plastic-coated pipelines, reflecting an update to Woodside's assumptions based on decommissioning planning activities in 2021), offset by a revision of discount rates of $134 million and provisions used of $45 million.
2. 2021 change in provision is due to provisions used of $45 million and changes in estimates of $95 million.

Recognition and measurement

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Restoration

The restoration provision is first recognised in the period in which the obligation arises. The nature of restoration activities includes the removal of facilities, abandonment of wells and restoration of affected areas. Restoration provisions are updated annually, with the corresponding movement recognised against the related exploration and evaluation assets or oil and gas properties.

Over time, the liability is increased for the change in the present value based on a pre-tax discount rate appropriate to the risks inherent in the liability. The unwinding of the discount is recorded as an accretion charge within finance costs. The carrying amount capitalised in oil and gas properties is depreciated over the useful life of the related asset (refer to Note B.3).

Costs incurred that relate to an existing condition caused by past operations, and which do not have a future economic benefit, are expensed.

Employee benefits

Provision is made for employee benefits accumulated as a result of employees rendering services up to the end of the reporting period. These benefits include wages, salaries, annual leave and long service leave.

Liabilities in respect of employees' services rendered that are not expected to be wholly settled within one year after the end of the period in which the employees render the related services are recognised as long-term employee benefits.

These liabilities are measured at the present value of the estimated future cash outflow to the employees using the projected unit credit method. Liabilities expected to be wholly settled within one year after the end of the period in which the employees render the related services are classified as short-term benefits and are measured at the amount due to be paid.

D.5 Provisions (cont.)

Onerous contract provision

Provision is made for loss-making contracts at the present value of the lower of the net cost of fulfilling and the cost arising from failure to fulfill each contract. Long-term expectations of reduced spreads between North American and European/Asian LNG or gas markets has given rise to a loss-making contract.

Key estimates and judgements

(a) Restoration obligations

The Group estimates the future remediation and removal costs of offshore oil and gas platforms, production facilities, wells and pipelines at different stages of the development and construction of assets or facilities. In many instances, removal of assets occurs many years into the future.

The Group's restoration obligations are based on compliance with the requirements of relevant regulations which vary for different jurisdictions and are often non-prescriptive. Australian legislation requires removal of structures, equipment and property, or alternative arrangements to removal which are satisfactory to the regulator. The Group maintains technical expertise to ensure that industry learnings, scientific research and local and international guidelines are reviewed in assessing its restoration obligations.

The restoration obligation requires judgemental assumptions regarding removal date, environmental legislation and regulations, the extent of restoration activities required, the engineering methodology for estimating cost, future removal technologies in determining the removal cost, and liability-specific discount rates to determine the present value of these cash flows. The Group's provision includes the following costs:

- for onshore assets, provision has been made for the full removal of production facilities and aboveground pipelines.
- for offshore assets, provision has been made for the plug and abandonment of wells and the removal of offshore platform topsides, floating production storage offloading (FPSO) and some subsea infrastructure. It is currently the Group's assumption that certain pipelines and infrastructure, parts of offshore platform substructures, and certain subsea infrastructure remain in-situ where it can be demonstrated that this will deliver equal or better health, safety and environmental outcomes than full removal and that regulatory approval is obtained where arrangements are satisfactory to the regulator.

Elements composed of steel, or steel and concrete, with hydrocarbons removed have previously been accepted by the Australian regulator to be decommissioned in-situ where it has been demonstrated there is an acceptable impact to the environment and to current and future marine users (i.e. fishing, shipping and other activities).

The basis of the restoration obligation provision for assets with approved decommissioning plans or general directions issued by the regulator can differ from the assumptions disclosed above. Whilst the provisions reflect the Group's best estimate based on current knowledge and information, further studies and detailed analysis of the restoration activities for individual assets will be performed near the end of their operational life and/or when detailed decommissioning plans are required to be submitted to the relevant regulatory authorities. Actual costs and cash outflows can materially differ from the current estimate as a result of changes in regulations and their application, prices, analysis of site conditions, further studies, timing of restoration and changes in removal technology. These uncertainties may result in actual expenditure differing from amounts included in the provision recognised as at 31 December 2021.

A range of pre-tax discount rates between 0.4% and 2.4% (2020: 0.1% to 2%) has been applied. If the discount rates were decreased by 0.5% then the provision would be $134 million higher. If the cost estimates were increased by 10% then the provision would be $225 million higher. The proportion of the non-current balance not expected to be settled within 10 years is 65% (2020: 73%).

In the event that the removal of all, or a substantial portion of, the elements was required, Woodside estimates the additional cost would lead to an increase to the provision of approximately $300 - $500 million. This excludes costs related to large diameter trunklines between the offshore platforms and onshore plants as further assessment is required for these pipelines which are buried below the seabed or heavily stabilised by rock or concrete due to their location and metocean conditions.

(b) Long service leave

Long service leave is measured at the present value of benefits accumulated up to the end of the reporting period. The liability is discounted using an appropriate discount rate. Management uses judgement to determine key assumptions used in the calculation including future increases in salaries and wages, future on-cost rates and future settlement dates of employees' departures.

(c) Legal case outcomes

Provisions for legal cases are measured at the present value of the amount expected to settle the claim. Management is required to use judgement when assessing the likely outcome of legal cases, estimating the risked amount and whether a provision or contingent liability should be recognised.

(d) Onerous contracts

The onerous contract provision assessment requires management to make certain estimates regarding the unavoidable costs and the expected economic benefits from the contract. These estimates require significant management judgement and are subject to risk and uncertainty, and hence changes in economic conditions can affect the assumptions. The present value of the provision was estimated using the assumptions set out below:

- Contract term – 19 years; the provision is released as contract deliveries are made up to 2040.
- Discount rate – a pre-tax, risk free US government bond rate of 1.855% (2020: 1.390%) has been applied.
- LNG pricing – forecast sales and purchase prices are subject to a number of price markers. Price assumptions are based on the best information on the market available at measurement date and derived from short- and long-term views of global supply and demand, building upon past experience of the industry and consistent with external sources. The forecasted sales are linked to gas hub prices (Title Transfer Facility (TTF)) at which physical sales are expected to occur and incorporates known pricing information related to sales[1]. The long-term gas sales price is estimated on the basis of the Group's Brent price forecast. The estimated purchase price is linked to US gas hub prices (Henry Hub (HH)) at which physical purchases are expected to occur. The nominal TTF, Brent oil prices and HH gas prices used at 31 December 2021 were:

	2022	2023	2024	2025	2026
TTF (US$/MMBtu)	15.0	8.2	6.9	7.0	7.2
Brent (US$/bbl)	73	71	68	69	70[2]
HH (US$/MMBtu)	4.0	3.6	3.1	3.2	3.3[3]

The nominal impact of the effects of changes to discount rate and long-term price assumptions are estimated as follows:

Change in assumption[4]	US$m
LNG sales price[1]: increase of 10%	500
LNG sales price[1]: decrease of 10%	(509)
US hub gas price (HH)[3]: increase of 10%	(282)
US hub gas price (HH)[3]: decrease of 10%	282
Discount rate: increase of 1%[5]	19
Discount rate: decrease of 1%[5]	(20)

1. For committed volumes, contracted pricing has been applied. For hedge accounted volumes, the relevant hedged prices have been applied.
2. Long-term oil prices are based on US$65/bbl (2022 real terms) from 2024 and prices are escalated at 2.0% onwards.
3. Long-term gas prices are based on US$3.0/MMBtu (2022 real terms) from 2025 to 2029 and thereafter US$3.5/MMBtu (2022 real terms). All long-term prices are escalated at 2.0%.
4. Amounts shown represent the change of the present value of the contract keeping all other variables constant. Any reduction in the onerous provision recognised would not exceed the balance of the provision itself.
5. A change of 1% represents 100 basis points.

D.6 Other financial assets and liabilities

	2021 US$m	2020 US$m
Other financial assets		
Financial instruments at fair value through profit and loss		
Derivative financial instruments designated as hedges	134	31
Other financial assets	293	195
Total other financial assets	427	226
Current	320	172
Non-current	107	54
Net carrying amount	427	226
Other financial liabilities		
Financial instruments at fair value through profit and loss		
Derivative financial instruments designated as hedges	563	68
Other financial liabilities	9	3
Total other financial liabilities	572	71
Current	411	37
Non-current	161	34
Net carrying amount	572	71

Recognition and measurement

Other financial assets and liabilities

Receivables subject to provisional pricing adjustments are initially recognised at the transaction price and subsequently measured at fair value with movements recognised in the income statement.

Derivative financial instruments

Derivative financial instruments that are designated within qualifying hedge relationships are initially recognised at fair value on the date the contract is entered into. For relationships designated as fair value hedges, subsequent fair value movements of the derivative are recognised in the income statement. For relationships designated as cash flow hedges, subsequent fair value movements of the derivative for the effective portion of the hedge are recognised in other comprehensive income and accumulated in reserves in equity; fair value movements for the ineffective portion are recognised immediately in the income statement. Costs of hedging have been separated from the hedging arrangements and deferred to other comprehensive income and accumulated in reserves in equity. Amounts accumulated in equity are reclassified to the income statement in the periods when the hedged item affects profit or loss.

Hedge effectiveness is determined at the inception of the hedge relationship, and through periodic prospective effectiveness assessments to ensure that an economic relationship exists between the hedged exposure and the hedging instrument. The Group assesses whether the derivative designated in each hedging relationship has been, and is expected to be, effective in offsetting changes in cash flows of the hedged exposure using the hypothetical derivative method.

Ineffectiveness is recognised where the cumulative change in the designated component value of the hedging instrument on an absolute basis exceeds the change in value of the hedged exposure attributable to the hedged risk.

Ineffectiveness may arise where the timing of the transaction changes from what was originally estimated such as delayed shipments or changes in timing of forecast sales. This may also arise where the commodity swap pricing terms do not perfectly match the pricing terms of the LNG revenue contracts.

Fair value

Except for the other financial assets and other financial liabilities set out in this note, there are no material financial assets or financial liabilities carried at fair value.

The fair value of commodity derivative financial instruments is determined based on observable quoted forward pricing and swap models and is classified as Level 2 on the fair value hierarchy. The most frequently applied valuation techniques include forward pricing and swap models that use present value calculations. The models incorporate various inputs including the credit quality of counterparties and forward rate curves of the underlying commodity.

The fair value of interest rate swaps is calculated by discounting estimated future cash flows based on the terms of maturity of each contract, using market interest rates for a similar instrument at the reporting date and is classified as Level 2 on the fair value hierarchy.

The fair value of foreign exchange forward contracts is determined using quoted forward exchange rates at the reporting date and present value calculations based on high credit quality yield curves in the respective currencies and is classified as Level 2 on the fair value hierarchy.

The fair values of other financial assets and other financial liabilities are predominantly determined based on observable quoted forward pricing and are predominantly classified as Level 2 on the fair value hierarchy.

Foreign exchange

The derivative financial instruments include foreign exchange forward contracts that are denominated in Australian dollars. The Group had no material other financial assets and liabilities denominated in currencies other than US dollars.

Hedging activities

During the period, the following hedging activities were undertaken:

- The Group hedged a percentage of its oil-linked exposure, entering into oil swap derivatives settling between 2021 to 2023 in order to achieve a minimum average sales price per barrel.
- The Group also entered into separate HH commodity swaps to hedge the purchase leg of the Corpus Christi volumes and separate TTF commodity swaps to hedge the sales leg of Corpus Christi volumes effectively protecting against pricing risk for 2022 and 2023. As a result of hedging and term sales, approximately 97% of Corpus Christi volumes in 2022 and 70% in 2023 have hedged pricing risk.
- The Group entered into TTF commodity swaps to hedge equity LNG cargoes expected to be exposed to winter 2021/22 natural gas pricing.
- The Group entered into foreign exchange forward contracts to fix the Australian dollar to US dollar exchange rate in relation to a portion of the Australian dollar denominated capital expenditure expected to be incurred under the Scarborough development.

D.6 Other financial assets and liabilities (cont.)

Hedging activities (cont.)

For the year ended 31 December 2020 the following main hedging activities were undertaken:

The Group hedged a percentage of its exposure to commodity price risk, entering into 13.4 million barrels of oil swap derivatives to achieve a minimum average sales price of $33 per barrel. The Group also entered into 7.9 million barrels of oil call options, to take advantage of increases in oil prices above $40 per barrel, for a premium of $37 million. Most of the derivatives settled between April 2020 and December 2020, with swaps and options for 1.3 million barrels settling in 2021. The swaps and call options were designated as cash flow hedges.

	2021	2020
Oil swaps (cash flow hedges)		
Carrying amount (US$m)	(1)	(22)
Notional amount (MMbbl)	30	1
Maturity date	2022-2023	2021
Hedge ratio	1:1	1:1
Weighted average hedged rate (US$/MMbbl)	74	33
HH Corpus Christi commodity swaps (cash flow hedges)		
Carrying amount (US$m)	31	-
Notional amount (TBtu)	65	-
Maturity date	2022-2023	-
Hedge ratio	1:1	-
Weighted average hedged rate (US$/MMBtu)	3	-
TTF Corpus Christi commodity swaps (cash flow hedges)		
Carrying amount (US$m)	(465)	-
Notional amount (TBtu)	49	-
Maturity date	2022-2023	-
Hedge ratio	1:1	-
Weighted average hedged rate (US$/MMBtu)	9	-
TTF commodity swaps (cash flow hedges)		
Carrying amount (US$m)	4	-
Notional amount (TBtu)	3	-
Maturity date	2022	-
Hedge ratio	1:1	-
Weighted average hedged rate (US$/MMBtu)	26	-
Interest rate swap (cash flow hedges)		
Carrying amount (US$m)	(17)	(43)
Notional amount (US$m)	600	600
Maturity date	2027	2027
Hedge ratio	1:1	1:1
Weighted average hedged rate	1.7%	1.7%
Cross currency interest rate swap (cash flow and fair value hedges)		
Carrying amount (US$m)	9	15
Notional amount (Swiss Franc)	175	175
Maturity date	2023	2023
Hedge ratio	1:1	1:1
Weighted average hedged rate	Three month US$ LIBOR +2.8%	Three month US$ LIBOR +2.8%
Oil call options (cash flow hedges)		
Carrying amount (US$m)	-	13
Notional amount (MMbbl)	-	1
Maturity date	-	2021
Hedge ratio	-	1:1
Weighted average hedged rate (US$/MMbbl)	-	33
FX forwards (cash flow hedges)		
Carrying amount (US$m)	10	-
Notional amount (AUD$m)	934	-
Maturity date	2022-2025	-
Hedge ratio	1:1	-
Weighted average hedged rate (AUD:USD)	0.71	-

Hedge ineffectiveness of $38 million (2020: $1 million) has been recognised in the profit and loss.

Other financial assets

Other financial assets measured at fair value include receivables subject to provisional pricing adjustments of $163 million (2020: $144 million) and repurchase agreements entered into for the purposes of net settlement rather than for physical delivery of $69 million (2020: nil).

Interest Rate Benchmark Reform

A fundamental reform of major interest rate benchmarks is being undertaken globally, including the replacement of some interbank offered rates (IBORs) with alternative nearly risk-free rates (referred to as 'IBOR reform'). The Group has exposures to IBORs on its financial instruments that will be impacted as part of these market-wide initiatives. The Group's main IBOR exposure at the reporting date is USD LIBOR. In 2020, the Federal Reserve announced that LIBOR will be phased out and eventually replaced by June 2023.

The Group anticipates that IBOR reform will impact its operational and risk management processes and hedge accounting. The main risks to which the Group is exposed as a result of IBOR reform are operational, for example renegotiating borrowing contracts through bilateral negotiation with counterparties, implementing new fallback clauses with its derivative counterparties, updating contractual terms and revising operational controls related to the reform. Financial risk is predominantly limited to interest rate risk. Hedging relationships may experience ineffectiveness due to uncertainty about when and how replacement may occur with respect to the relevant hedged item and hedging instrument or the difference in the timing of a replacement.

The Group's financial instruments have not yet transitioned to an alternative interest rate benchmark. The Group has financial liabilities and financial assets with a total carrying value of $957 million and $367 million respectively, with reference to USD LIBOR.

The Group has the following hedging relationships which are exposed to interest rate benchmarks impacted by IBOR Reform:

- Interest rate swaps to hedge the LIBOR interest rate risk associated with the $600 million syndicated facility (refer to Note C.2). The interest rate swaps are designated as cash flow hedges, converting the variable interest into fixed interest US dollar debt, and mature in 2027.
- A fixed rate 175 million Swiss Franc (CHF) denominated medium term note, which it hedges with cross-currency interest rate swaps designated in both fair value and cash flow hedge relationships. The cross-currency interest rate swaps are referenced to LIBOR (refer to Note C.2).

The Group's Treasury function continues to assess the implications of the IBOR reform across the Group and will manage and execute the transition from current benchmark rates to alternative benchmark rates.

Key estimates and judgements

Fair value of other financial assets and liabilities

Estimates have been applied in the measurement of other financial assets and liabilities and, where required, judgement is applied in the settlement of any financial assets or liabilities. In the current period, this included a $56 million periodic adjustment which increased other financial liabilities, reflecting the arrangements governing Wheatstone LNG sales (2020: $12 million decrease).

D.7 Leases

	Land and buildings US$m	Plant and equipment US$m	Marine vessels and carriers US$m	Total US$m
Lease assets				
Year ended 31 December 2021				
Carrying amount at 1 January 2021	**392**	**-**	**592**	**984**
Additions	**14**	**205**	**9**	**228**
Lease remeasurements	**15**	**-**	**16**	**31**
Disposals at written down value	**(12)**	**-**	**-**	**(12)**
Depreciation	**(32)**	**(38)**	**(81)**	**(151)**
Carrying amount at 31 December 2021	**377**	**167**	**536**	**1,080**
At 31 December 2021				
Historical cost and remeasurements	**462**	**205**	**743**	**1,410**
Accumulated depreciation, impairment and disposals	**(85)**	**(38)**	**(207)**	**(330)**
Net carrying amount	**377**	**167**	**536**	**1,080**
Lease liabilities				
Year ended 31 December 2021				
At 1 January 2021	**484**	**3**	**791**	**1,278**
Additions	**7**	**231**	**13**	**251**
Repayments (principal and interest)	**(70)**	**(48)**	**(144)**	**(262)**
Accretion of interest	**25**	**7**	**65**	**97**
Lease remeasurements	**(9)**	**(1)**	**13**	**3**
Carrying amount at 31 December 2021	**437**	**192**	**738**	**1,367**
Current	**19**	**87**	**85**	**191**
Non-current	**418**	**105**	**653**	**1,176**
Carrying amount at 31 December 2021	**437**	**192**	**738**	**1,367**
Lease assets				
Year ended 31 December 2020				
Carrying amount at 1 January 2020	396	-	552	948
Additions	24	-	102	126
Lease remeasurements	1	-	4	5
Depreciation	(29)	-	(66)	(95)
Carrying amount at 31 December 2020	392	-	592	984
At 31 December 2020				
Historical cost	447	-	718	1,165
Accumulated depreciation and impairment	(55)	-	(126)	(181)
Net carrying amount	392	-	592	984
Lease liabilities				
Year ended 31 December 2020				
At 1 January 2020	431	-	739	1,170
Additions	24	3	107	134
Repayments (principal and interest)	(34)	-	(123)	(157)
Accretion of interest	23	-	63	86
Lease remeasurements	40	-	5	45
Carrying amount at 31 December 2020	484	3	791	1,278
Current	16	1	77	94
Non-current	468	2	714	1,184
Carrying amount at 31 December 2020	484	3	791	1,278

Recognition and measurement

When a contract is entered into, the Group assesses whether the contract contains a lease. A lease arises when the Group has the right to direct the use of an identified asset which is not substitutable and to obtain substantially all economic benefits from the use of the asset throughout the period of use. The leases recognised by the Group predominantly relate to LNG vessels, property and drilling rigs.

The Group separates the lease and non-lease components of the contract and accounts for these separately. The Group allocates the consideration in the contract to each component on the basis of their relative stand-alone prices.

Leases as a lessee

Lease assets and lease liabilities are recognised at the lease commencement date, which is when the assets are available for use. The assets are initially measured at cost, which is the present value of future lease payments adjusted for any lease payments made at or before the commencement date, plus any make-good obligations and initial direct costs incurred.

Lease assets are depreciated using the straight-line method over the shorter of their useful life and the lease term. Refer to Note B.3 for the useful lives of assets. Periodic adjustments are made for any re-measurements of the lease assets and for impairment losses, assessed in accordance with the Group's impairment policies.

Lease liabilities are initially measured at the present value of future minimum lease payments, discounted using the Group's incremental borrowing rate if the rate implicit in the lease cannot be readily determined, and are subsequently measured at amortised cost using the effective interest rate. Minimum lease payments are fixed payments or index-based variable payments incorporating the Group's expectations of extension options and do not include non-lease components of a contract. A portfolio approach was taken when determining the implicit discount rate for LNG vessels with similar terms and conditions on transition.

The lease liability is remeasured when there are changes in future lease payments arising from a change in rates, index or lease terms from exercising an extension or termination option. A corresponding adjustment is made to the carrying amount of the lease assets, with any excess recognised in the consolidated income statement.

There are no restrictions placed upon the lessee by entering into these leases.

Short-term leases and leases of low value

Short-term leases (lease term of 12 months or less) and leases of low value assets are recognised as incurred as an expense in the consolidated income statement. Low value assets comprise plant and equipment.

Foreign exchange risk

The Group held $476 million of lease liabilities at 31 December 2021 (2020: $518 million) in currencies other than the US dollar (predominantly Australian dollars).

D.7 Leases (cont.)

Maturity profile of lease liabilities

The table below presents the contractual undiscounted cash flows associated with the Group's lease liabilities, representing principal and interest. The figures will not necessarily reconcile with the amounts disclosed in the consolidated statement of financial position.

	2021 US$m	2020 US$m
Due for payment in:		
1 year or less	**283**	184
1-2 years	**283**	181
2-3 years	**191**	180
3-4 years	**171**	174
4-5 years	**161**	174
More than 5 years	**789**	994
	1,878	1,887

Lease commitments

The table below presents the contractual undiscounted cash flows associated with the Group's future lease commitments for non-cancellable leases not yet commenced, representing principal and interest.

	2021 US$m	2020 US$m
Due for payment:		
Within one year	**80**	90
After one year but not more than five years	**159**	365
Later than five years	**49**	45
	288	500

Subsequent to year end, contractual undiscounted future lease commitments for non-cancellable leases not yet commenced increased by $634 million. The leases commence from 2025 and relate to facilities, marine vessels and carriers (refer to Note E.5).

Payments of $68 million (2020: $101 million) for short-term leases (lease term of 12 months or less) and payments of $18 million (2020: $17 million) for leases of low value assets were expensed in the consolidated income statement. Total payments for leases in the statement of cash flows are $330 million (2020: $275 million), with $244 million (2020: $157 million) included in financing activities.

The Group has short-term and low value lease commitments for marine vessels and carriers, property, drill rigs and plant and equipment contracted for, but not provided for in the financial statements, of $53 million (2020: $94 million).

Key estimates and judgements

(a) Control

Judgement is required to assess whether a contract is or contains a lease at inception by assessing whether the Group has the right to direct the use of the identified asset and obtain substantially all the economic benefits from the use of that asset.

(b) Lease term

Judgement is required when assessing the term of the lease and whether to include optional extension and termination periods. Option periods are only included in determining the lease term at inception when they are reasonably certain to be exercised.

Lease terms are reassessed when a significant change in circumstances occurs. On this basis, possible additional lease payments amounting to $1,654 million (2020: $1,670 million) were not included in the measurement of lease liabilities.

(c) Interest in joint arrangements

Judgement is required to determine the Group's rights and obligations for lease contracts within joint operations, to assess whether lease liabilities are recognised gross (100%) or in proportion to the Group's participating interest in the joint operation. This includes an evaluation of whether the lease arrangement contains a sublease with the joint operation.

(d) Discount rates

Judgement is required to determine the discount rate, where the discount rate is the Group's incremental borrowing rate if the rate implicit in the lease cannot be readily determined. The incremental borrowing rate is determined with reference to the Group's borrowing portfolio at the inception of the arrangement or the time of the modification.

NOTES TO THE FINANCIAL STATEMENTS E. OTHER ITEMS

for the year ended 31 December 2021

In this section

This section addresses information on items which require disclosure to comply with Australian Accounting Standards and the *Corporations Act 2001*, however are not considered critical in understanding the financial performance or position of the Group. This section includes Group structure information and other disclosures.

E.1 Contingent liabilities and assets

	2021 US$m	2020[1] US$m
Contingent liabilities at reporting date		
Contingent liabilities	195	587
Guarantees	7	10
	202	597

1. Contingent payments of $450 million were paid in 2021 due to a positive FID to develop the Scarborough field and capitalised to oil and gas properties.

Contingent liabilities relate predominantly to possible obligations whose existence will only be confirmed by the occurrence or non-occurrence of uncertain future events, and therefore the Group has not provided for such amounts in these financial statements. Additionally, there are a number of other claims and possible claims that have arisen in the course of business against entities in the Group, the outcome of which cannot be estimated at present and for which no amounts have been included in the table above.

The above table includes contingent payments of $155 million (31 December 2020: $100 million) relating to the Sangomar development, dependent on commodity prices and the timing of first oil.

Additionally, the Group has issued guarantees relating to workers' compensation liabilities.

There were no contingent assets as at 31 December 2021 or 31 December 2020.

E.2 Employee benefits

	2021 US$m	2020 US$m
Employee benefits	217	252
Share-based payments	12	19
Defined contribution plan costs	26	27
Defined benefit plan expense	1	2
	256	300

(a) Employee benefits

Employee benefits for the reporting period are as follows:

Recognition and measurement

The Group's accounting policy for employee benefits other than superannuation is set out in Note D.5. The policy relating to share-based payments is set out in Note E.2(c).

All employees of the Group are entitled to benefits on retirement, disability or death from the Group's superannuation plan. The majority of employees are party to a defined contribution scheme and receive fixed contributions from Group companies and the Group's legal or constructive obligation is limited to these contributions. Contributions to defined contribution funds are recognised as an expense as they become payable. Prepaid contributions are recognised as an asset to the extent that a cash refund or a reduction in the future payment is available. The Group also operates a defined benefit superannuation scheme, the membership of which is now closed. The net defined benefit plan asset at 31 December 2021 was $33 million (2020: $19 million).

(b) Compensation of key management personnel

Key management personnel (KMP) compensation for the financial year was as follows:

	2021 US$	2020 US$
Short-term employee benefits	6,599,678	5,868,476
Post-employment benefits	77,515	63,805
Share-based payments	5,609,022	7,201,653
Long-term employee benefits	717,223	515,585
Termination benefits	2,447,525	390,087
	15,450,963	14,039,606

(c) Share plans

The Group provides benefits to its employees (including KMP) in the form of share-based payments whereby employees render services for shares (equity-settled transactions).

Woodside equity plan (WEP) and supplementary Woodside equity plan (SWEP)

The WEP is available to all permanent employees, but since 1 January 2018 has excluded EIS participants. The number of Equity Rights (ERs) offered to each eligible employee is calculated with reference to salary and performance. The linking of performance to an allocation allows the Group to recognise and reward eligible employees for high performance. The ERs have no further ongoing performance conditions after allocation, and do not require participants to make any payment in respect of the ERs at grant or at vesting.

Each ER relating to the WEP for 2018 and prior years entitles the participant to receive a Woodside share on a vesting date three years after the grant date. From the 2019 WEP onwards, 75% of the ERs offered to each participant will vest three years after the grant date, with the remaining 25% vesting five years after the grant date.

The SWEP award is available to employees identified as being retention critical. Each ER entitles the participant to receive a Woodside share on the vesting date three years after the effective grant date. Participants do not make any payment in respect of the ERs at grant or at vesting.

Executive incentive plans (EIP)

The EIP operated as Woodside's Executive incentive framework until the end of 2017, after which the Board introduced the EIS. The EIP was used to deliver short-term awards (STA) and long-term awards (LTA) to Senior Executives.

Short-term awards (STA)

STAs were delivered in the form of restricted shares to Executives, including all Executive KMP. There are no further performance conditions for vesting of deferred STA. Participants are not required to make any payments in respect of STA awards at grant or at vesting. Restricted shares entitle their holders to receive dividends.

Long-term awards (LTA)

LTAs were granted in the form of Performance Rights (PRs) to Executives, including all Executive KMP. Vesting of LTA is subject to achievement of relative total shareholder return (RTSR) targets, with 33% measured against the ASX 50 and the remaining 67% tested against an international group of oil and gas companies.

Participants are not entitled to receive dividends and are not required to make any payments in respect of LTA awards at grant or at vesting.

E.2 Employee benefits (cont.)

Executive incentive scheme (EIS)

The EIS was introduced for the 2018 performance year for all Executives including Executive KMP. The EIS is delivered in the form of a cash incentive, Restricted Shares and Performance Rights. The grant date of the Restricted Shares and Performance Rights has been determined to be subsequent to the performance year, being the date of the Board of Directors' approval. Accordingly, the 2020 Restricted Shares and Performance Rights for Executives were granted on 17 February 2021, while the Performance Rights for the outgoing CEO were granted on 15 April 2021 and have been included in the table below. The expense estimated as at 31 December 2021 in relation to the 2021 performance year was updated to the fair value on grant date during the period.

The 2021 Restricted Shares and Performance Rights have not been included in the table below as they have not been approved as at 31 December 2021. An expense related to the 2021 performance year has been estimated for Restricted Shares and Performance Rights, using fair value estimates based on inputs at 31 December 2021.

Recognition and measurement

All compensation under WEP, SWEP and Executive share plans is accounted for as share-based payments to employees for services provided. The cost of equity-settled transactions with employees is measured by reference to the fair values of the equity instruments at the date at which they are granted. The fair value of share-based payments is recognised, together with the corresponding increase in equity, over the period in which the vesting conditions are fulfilled, ending on the date on which the relevant employee becomes fully entitled to the shares. At each balance sheet date, the Group reassesses the number of awards that are expected to vest based on service conditions. The expense recognised each year takes into account the most recent estimate.

The fair value of the benefit provided for the WEP and SWEP is estimated using the Black-Scholes option pricing technique. The fair value of the restricted shares is estimated as the closing share price at grant date. The fair value of the benefit provided for the RTSR PRs was estimated using the Binomial or Black-Scholes option pricing technique combined with a Monte Carlo simulation methodology, where relevant, using historical volatility to estimate the volatility of the share price in the future.

The number of awards and movements for all share plans are summarised as follows:

	Number of performance awards			
	Employee plans		Executive plans	
	WEP	SWEP	STA[3]	LTA[3]
Year ended 31 December 2021				
Opening balance	**5,618,603**	**-**	**975,295**	**2,798,305**
Granted during the year[1,2]	**2,507,167**	**-**	**353,412**	**553,849**
Vested during the year	**(1,999,676)**	**-**	**(307,402)**	**(322,746)**
Forfeited during the year	**(476,311)**	**-**	**(26,869)**	**(650,188)**
Awards at 31 December 2021	**5,649,783**	**-**	**994,436**	**2,379,220**
	US$m	**US$m**	**US$m**	**US$m**
Fair value of awards granted during the year	**39**	**-**	**7**	**9**

	Number of performance awards			
	Employee plans		Executive plans	
	WEP	SWEP	STA[3]	LTA[3]
Year ended 31 December 2020				
Opening balance	6,911,551	17,678	867,716	2,704,143
Granted during the year[1,2]	1,127,546	-	373,774	617,091
Vested during the year	(1,943,777)	(17,678)	(257,489)	(242,608)
Forfeited during the year	(476,717)	-	(8,706)	(280,321)
Awards at 31 December 2020	5,618,603	-	975,295	2,798,305
	US$m	**US$m**	**US$m**	**US$m**
Fair value of awards granted during the year	13	-	9	12

1. For the purpose of valuation, the share price on grant date for the 2021 WEP allocations was $15.17 (2020: WEP allocations $12.57).
2. For the purpose of valuation, the share price on grant date for Restricted Shares was $20.18 (2020: $22.76) and Performance Rights were $11.66 and $14.44 (2020: $15.81).
3. Includes awards issued under EIP and EIS.

For more detail on these share plans and performance rights issued to KMPs, refer to the Remuneration Report on pages 69-92.

E.3 Related party transactions

Transactions with directors

There were no transactions with directors during the year. Key management personnel compensation is disclosed in Note E.2(b).

E.4 Auditor remuneration

The auditor of Woodside Petroleum Ltd is Ernst & Young (EY).

	2021 US$000	2020 US$000
Amounts received or due and receivable to:		
Ernst & Young (Australia)		
- Fees for auditing the statutory financial report of the parent covering the group and auditing the statutory financial reports of any controlled entities	**1,455**	1,521
- Fees for assurance services that are required by legislation to be provided by the auditor	**2,687**	-
- Fees for other assurance and agreed upon procedures services under other legislation or contractual arrangements where there is discretion as to whether the service is provided by the auditor or another firm	**22**	110
- Other services	**134**	164
	4,298	1,795
Other overseas member firms of Ernst & Young (Australia)		
- Audit of the financial reports of controlled entities	**277**	165
- Fees for other assurance and agreed upon procedures services under other legislation or contractual arrangements where there is discretion as to whether the service is provided by the auditor or another firms	**11**	30
- Other services	**14**	14
	302	209

E.5 Events after the end of the reporting period

On 15 November 2021, the Group and Global Infrastructure Partners (GIP) entered into a Sale and Purchase Agreement for GIP to acquire a 49% participating interest in the Pluto Train 2 Joint Venture. The transaction completed on 18 January 2022, reducing the Group's participating interest from 100% to 51% and reducing the Group's future capital commitments by approximately $2,876 million. The full financial effect of the transaction is still being assessed.

Subsequent to year end, the Group entered into new lease arrangements (refer to Note D.7).

E.6 Joint arrangements

(a) Interest percentage in joint ventures

Entity	Principal activity	Group Interest % 2021	Group Interest % 2020
North West Shelf Gas Pty Ltd	Marketing services for ventures in the sale of gas to the domestic market.	**16.67**	16.67
North West Shelf Liaison Company Pty Ltd	Liaison for ventures in the sale of LNG to the Japanese market.	**16.67**	16.67
China Administration Company Pty Ltd	Marketing services for ventures in the sale of LNG to international markets.	**16.67**	16.67
North West Shelf Shipping Service Company Pty Ltd	LNG vessel fleet advisor.	**16.67**	16.67
North West Shelf Lifting Coordinator Pty Ltd	Coordinator for venturers for all equity liftings.	**16.67**	16.67

(b) Interest percentage in joint operations

	Group Interest % 2021	Group Interest % 2020
Producing and developing assets		
Oceania		
North West Shelf	**12.5 - 50**	12.5 - 50
Greater Enfield and Vincent	**60.0**	60.0
Stybarrow	**50.0**	50.0
Balnaves	**65.0**	65.0
Pluto	**90.0**	90.0
Wheatstone	**13.0 - 65.0**	13.0 - 65.0
Scarborough[1]	**73.5**	-
Africa		
Senegal[2]	**82.0**	68.3
Exploration and evaluation assets		
Oceania		
Browse Basin	**30.6**	30.6
Carnarvon Basin and Scarborough[1]	**15.8 - 70.0**	15.8 - 73.5
Bonaparte Basin	**26.7 - 35.0**	26.7 - 35.0
Africa		
Congo	**42.5**	42.5
Senegal[2]	**90.0**	75.0
Americas		
Kitimat[3]	**50.0**	50.0
Asia		
Republic of Korea	**50.0**	50.0
Myanmar[4]	**40.0 - 50.0**	40.0 - 50.0
Europe		
Ireland[5]	**-**	90.0
Bulgaria[5]	**-**	30.0

1. FID taken on permits WA-61-L and WA-62-L announced on 22 November 2021.
2. Following the completion of the sale of FAR's interest in the RSSD joint venture during the year, Woodside's participating interest increased to 82% in the exploitation area and 90% in the exploration area (refer to Note B.5 more details).
3. Woodside is retaining an upstream position in the Liard Basin by taking on full equity in 28 non-infrastructure related Liard Basin leases from Chevron Canada.
4. The Group completed the relinquishment of permits AD-2, AD-5 and A-4 in 2021 and is in the process of withdrawing from AD-6, AD-7 and A-7. In 2022, the Group will also commence arrangements to formally exit AD-1, AD-8, the A-6 Joint Venture and the A-6 production sharing contract.
5. Licence surrendered in 2021.

The principal activities of the joint operations above are exploration, development and production of hydrocarbons.

Key estimates and judgements

Accounting for interests in other entities

Judgement is required in assessing the level of control obtained in a transaction to acquire an interest in another entity; depending upon the facts and circumstances in each case, Woodside may obtain control, joint control or significant influence over the entity or arrangement. Judgement is applied when determining the relevant activities of a project and if joint control is held over it.

Relevant activities include, but are not limited to, work program and budget approval, investment decision approval, voting rights in joint operating committees, amendments to permits and changes to joint arrangement participant holdings. Transactions which give Woodside control of a business are business combinations. If Woodside obtains joint control of an arrangement, judgement is also required to assess whether the arrangement is a joint operation or a joint venture.
If Woodside has neither control nor joint control, it may be in a position to exercise significant influence over the entity, which is then accounted for as an associate.

E.6 Joint arrangements (cont.)

Recognition and measurement

Joint arrangements are arrangements in which two or more parties have joint control. Joint control is the contractual agreed sharing of control of the arrangement which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control. Joint arrangements are classified as either a joint operation or joint venture, based on the rights and obligations arising from the contractual obligations between the parties to the arrangement.

To the extent the joint arrangement provides the Group with rights to the individual assets and obligations arising from the joint arrangement, the arrangement is classified as a joint operation, and as such the Group recognises its:

- assets, including its share of any assets held jointly;
- liabilities, including its share of any liabilities incurred jointly;
- revenue from the sale of its share of the output arising from the joint operation;
- share of revenue from the sale of the output by the joint operation; and
- expenses, including its share of any expenses incurred jointly.

To the extent the joint arrangement provides the Group with rights to the net assets of the arrangement, the investment is classified as a joint venture and accounted for using the equity method.

Joint arrangements acquired which are deemed to be carrying on a business are accounted for applying the principles of AASB 3 *Business Combinations*. Joint arrangements which are not deemed to be carrying on a business are treated as asset acquisitions.

E.7 Parent entity information

	2021 US$m	2020 US$m
Woodside Petroleum Ltd:		
Current assets	456	444
Non-current assets	10,037	10,257
Current liabilities	(357)	-
Non-current liabilities	(300)	(579)
Net assets	9,836	10,122
Issued and fully paid shares	9,409	9,297
Shares reserved for employee share plans	(30)	(23)
Employee benefits reserve	112	117
Foreign currency translation reserve	296	296
Distributable profits reserve	58	462
Retained earnings	(9)	(27)
Total shareholders equity	9,836	10,122
Profit of parent entity	18	852
Total comprehensive income of parent entity	18	852

Guarantees

Woodside Petroleum Ltd and Woodside Energy Ltd (a subsidiary company) are parties to a Deed of Cross Guarantee as disclosed in Note E.8. The effect of the Deed is that Woodside Petroleum Ltd has guaranteed to pay any deficiency in the event of winding up of the subsidiary company under certain provisions of the *Corporations Act 2001*. The subsidiary company has also given a similar guarantee in the event that Woodside Petroleum Ltd is wound up.

Woodside Petroleum Ltd has guaranteed the discharge by a subsidiary company of its financial obligations under debt facilities disclosed in Note C.2. Woodside Petroleum Ltd has guaranteed certain obligations of subsidiaries to unrelated parties on behalf of their performance in contracts. No liabilities are expected to arise from these guarantees.

E.8 Subsidiaries

(a) Subsidiaries

Name of entity	Notes
Ultimate Parent Entity	
Woodside Petroleum Ltd	(1,2,3)
Subsidiaries	
Company name	
Woodside Energy Ltd	(2,3,4)
Woodside Browse Pty Ltd	(2,4)
Woodside Burrup Pty Ltd	(2,4)
Burrup Facilities Company Pty Ltd	(5)
Burrup Train 1 Pty Ltd	(5)
Pluto LNG Pty Ltd	(5)
Woodside Burrup Train 2 A Pty Ltd	(2,4)
Woodside Burrup Train 2 B Pty Ltd	(2,4)
Woodside Energy (LNG Fuels and Power) Pty Ltd	(2,4)
Woodside Energy (Domestic Gas) Pty Ltd	(2,4)
Woodside Energy (Algeria) Pty Ltd	(2,4)
Woodside Energy Australia Asia Holdings Pte Ltd ◢	(4)
Woodside Energy Holdings International Pty Ltd	(2,4)
Woodside Energy Mediterranean Pty Ltd	(2,4)
Woodside Energy International (Canada) Limited ◀	(4)
Woodside Energy (Canada LNG) Limited ◀	(4)
Woodside Energy (Canada PTP) Limited ◀	(4)
KM LNG Operating General Partnership ◀	(8)
KM LNG Operating Ltd ◀	(4)
Woodside Energy Holdings Pty Ltd	(2,4)
Woodside Energy Holdings (USA) Inc ▼	(4)
Woodside Energy (USA) Inc ▼	(4)
Gryphon Exploration Company ▼	(4)
Woodside Energy (Cameroon) SARL ■	(4)
Woodside Energy (Gabon) Pty Ltd	(2,4)
Woodside Energy (Indonesia) Pty Ltd	(2,4)
Woodside Energy (Indonesia II) Pty Ltd	(2,4)
Woodside Energy (Malaysia) Pty Ltd	(2,4,10)
Woodside Energy (Ireland) Pty Ltd	(2,4)
Woodside Energy (Korea) Pte Ltd ◢	(4)
Woodside Energy (Korea II) Pte Ltd ◢	(4)
Woodside Energy (Myanmar) Pte Ltd ◢	(4)
Woodside Energy (Morocco) Pty Ltd	(2,4)
Woodside Energy (New Zealand) Limited ◤	(4)
Woodside Energy (New Zealand 55794) Limited ◤	(4)
Woodside Energy (Peru) Pty Ltd	(2,4)
Woodside Energy (Senegal) Pty Ltd	(2,4)
Woodside Energy (Tanzania) Limited ◘	(6)
Woodside Energy Holdings II Pty Ltd	(2,4)
Woodside Power Pty Ltd	(2,4)
Woodside Power (Generation) Pty Ltd	(2,4)
Woodside Energy Holdings (South America) Pty Ltd	(2,4)
Woodside Energia (Brasil) Apoio Administrativo Ltda ●	(7)
Woodside Energy Holdings (UK) Pty Ltd	(2,4)
Woodside Energy (UK) Limited ▲	(4)
Woodside Energy Finance (UK) Limited ▲	(4)
Woodside Energy (Congo) Limited ▲	(4)
Woodside Energy (Bulgaria) Limited ▲	(4)
Woodside Energy Holdings (Senegal) Limited ▲	(4)
Woodside Energy (Senegal) B.V. ⬢	(4)
Woodside Energy (France) SAS ○	(4)
Woodside Energy Iberia S.A. ◖	(4)
Woodside Energy (N.A.) Ltd ▲	(4)
Woodside Energy Services (Qingdao) Co Ltd ◆	(4)
Woodside Energy Julimar Pty Ltd	(2,4)
Woodside Energy (Norway) Pty Ltd	(2,4)
Woodside Energy Technologies Pty Ltd	(2,4,9)
Woodside Technology Solutions Pty Ltd	(2,4)
Woodside Energy Scarborough Pty Ltd	(2,4,11)
Woodside Energy Carbon Holdings Pty Ltd	(2,4,12)
Woodside Energy Carbon (Assets) Pty Ltd	(2,4,13)
Woodside Energy Carbon (Services) Pty Ltd	(2,4,13)
Woodside Energy (Financial Advisory Services) Pty Ltd	(2,4,13)
Woodside Energy Trading Singapore Pte Ltd ◢	(4)
WelCap Insurance Pte Ltd ◢	(4)
Woodside Energy Shipping Singapore Pte Ltd ◢	(4)
Metasource Pty Ltd	(2,4)
Mermaid Sound Port and Marine Services Pty Ltd	(2,4)
Woodside Finance Limited	(2,4)
Woodside Petroleum (Timor Sea 19) Pty Ltd	(2,4)
Woodside Petroleum (Timor Sea 20) Pty Ltd	(2,4)
Woodside Petroleum Holdings Pty Ltd	(2,4)

1. Woodside Petroleum Ltd is the ultimate holding company and the head entity within the tax consolidated group.
2. These companies were members of the tax consolidated group at 31 December 2021.
3. Pursuant to ASIC Instrument 2016/785, relief has been granted to the controlled entity, Woodside Energy Ltd, from the *Corporations Act 2001* requirements for the preparation, audit and publication of accounts. As a condition of the Instrument, Woodside Petroleum Ltd and Woodside Energy Ltd are parties to a Deed of Cross Guarantee.
4. All subsidiaries are wholly owned except those referred to in Notes 5, 6, 7 and 8.
5. Kansai Electric Power Australia Pty Ltd and Tokyo Gas Pluto Pty Ltd each hold a 5% interest in the shares of these subsidiaries. These subsidiaries are controlled.
6. As at 31 December 2021, Woodside Energy Holdings Pty Ltd held a 99.99% interest in the shares of Woodside Energy (Tanzania) Limited and Woodside Energy Ltd held the remaining 0.01% interest.
7. As at 31 December 2021, Woodside Energy Holdings (South America) Pty Ltd held a 99.99% interest in the shares of Woodside Energia (Brasil) Apoio Administrativo Ltda and Woodside Energy Ltd held the remaining 0.01% interest.
8. As at 31 December 2021, Woodside Energy International (Canada) Limited and Woodside Energy (Canada LNG) Limited were the general partners of the KM LNG Operating General Partnership holding a 99.99% and 0.01% partnership interest, respectively.
9. Woodside Energy Technologies Pty Ltd owns 30% in Blue Ocean Seismic Services Limited which is accounted for as an investment in associate.
10. On 4 May 2021, Woodside Energy (Indonesia III) Pty Ltd changed its name to Woodside Energy (Malaysia) Pty Ltd.
11. Woodside Energy Scarborough Pty Ltd was incorporated on 13 May 2021.
12. Woodside Energy Carbon Holdings Pty Ltd was incorporated on 29 July 2021.
13. Woodside Energy Carbon (Assets) Pty Ltd, Woodside Energy Carbon (Services) Pty Ltd and Woodside Energy (Financial Advisory Services) Pty Ltd were incorporated on 3 August 2021.

All subsidiaries were incorporated in Australia unless identified with one of the following symbols:

● Brazil	⬢ The Netherlands	◘ Tanzania
■ Cameroon	◤ New Zealand	▲ England and Wales
◀ Canada	◢ Singapore	▼ USA
○ France	◖ Spain	◆ China

Classification

Subsidiaries are all the entities over which the Group has the power over the investee such that the Group is able to direct the relevant activities, has exposure, or rights, to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect the amount of the investor's returns.

E.8 Subsidiaries (cont.)

(b) Subsidiaries with material non-controlling interests

The Group has two Australian subsidiaries with material non-controlling interests (NCI).

Name of entity	Principal place of business	% held by NCI
Burrup Facilities Company Pty Ltd	Australia	10%
Burrup Train 1 Pty Ltd	Australia	10%

The NCI in both subsidiaries is 10% held by the same parties (refer to Note E.8(a) footnote 5 for details).

The summarised financial information (including consolidation adjustments but before intercompany eliminations) of subsidiaries with material NCI is as follows:

	2021 US$m	2020 US$m
Burrup Facilities Company Pty Ltd		
Current assets	518	425
Non-current assets	5,038	5,224
Current liabilities	(71)	(51)
Non-current liabilities	(528)	(571)
Net assets	4,957	5,027
Accumulated balance of NCI	496	503
Revenue	858	859
Profit	328	318
Profit allocated to NCI	33	32
Dividends paid to NCI	(40)	(32)
Operating	633	652
Investing	(111)	(69)
Financing	(522)	(583)
Net increase/(decrease) in cash and cash equivalents	-	-
Burrup Train 1 Pty Ltd		
Current assets	435	372
Non-current assets	2,915	3,081
Current liabilities	(110)	(103)
Non-current liabilities	(345)	(385)
Net assets	2,895	2,965
Accumulated balance of NCI	290	297
Revenue	1,421	1,423
Profit	200	208
Profit allocated to NCI	20	21
Dividends paid to NCI	(27)	(13)
Operating	393	473
Investing	(4)	(2)
Financing	(389)	(471)
Net increase/(decrease) in cash and cash equivalents	-	-

(c) Deed of Cross Guarantee and Closed Group

Woodside Petroleum Ltd and Woodside Energy Ltd are parties to a Deed of Cross Guarantee under which each company guarantees the debts of the other. By entering into the Deed, the entities have been granted relief from the *Corporations Act 2001* requirements for the preparation, audit and publication of accounts, pursuant to ASIC Instrument 2016/785. The two entities represent a Closed Group for the purposes of the Instrument.

The consolidated income statement and statement of financial position of the members of the Closed Group are set out below:

	2021 US$m	2020 US$m
Closed Group Consolidated Income Statement and Statement of Retained Earnings		
Profit/(loss) before tax	1,599	(3,195)
Tax (expense)/benefit	(50)	955
Profit/(loss) after tax	1,549	(2,240)
Retained earnings at the beginning of the financial year	111	3,579
Transfer of retained earnings to distributable profits reserve	-	(710)
Dividends	-	(518)
Retained earnings at the end of the financial year	1,660	111
Closed Group Consolidated Statement of Financial Position		
Current assets		
Cash and cash equivalents	160	131
Receivables	948	488
Inventories	47	46
Other financial assets	173	118
Other assets	22	20
Total current assets	1,350	803
Non-current assets		
Receivables	40	29
Inventories	-	19
Other financial assets	36,432	31,771
Exploration and evaluation assets	31	1,059
Oil and gas properties	2,758	2,688
Other plant and equipment	172	185
Deferred tax assets	579	580
Lease assets	319	340
Other assets	13	-
Total non-current assets	40,344	36,671
Total assets	41,694	37,474
Current liabilities		
Payables	186	156
Other financial liabilities	409	46
Other liabilities	34	48
Provisions	320	261
Tax payable	357	-
Lease liabilities	23	24
Total current liabilities	1,329	535
Non-current liabilities		
Payables	26,668	24,570
Deferred tax liabilities	-	-
Other financial liabilities	153	-
Other liabilities	15	12
Provisions	1,179	1,272
Lease liabilities	360	392
Total non-current liabilities	28,375	26,246
Total liabilities	29,704	26,781
Net assets	11,990	10,693
Equity		
Issued and fully paid shares	9,409	9,297
Shares held for employee share plan	(30)	(23)
Other reserves	951	1,308
Retained earnings	1,660	111
Total equity	11,990	10,693

E.9 Other accounting policies

(a) Summary of other significant accounting policies

Tax consolidation

The parent and its wholly owned Australian controlled entities have elected to enter a tax consolidation, with Woodside Petroleum Ltd as the head entity of the tax consolidated group. The members of the tax consolidated group are identified in Note E.8(a).

The tax expense/benefit, deferred tax liabilities and deferred tax assets arising from temporary differences of the members of the tax consolidated group are recognised in the separate financial statements of the members of the tax consolidated group, using the stand-alone approach.

Entities within the tax consolidated group have entered into a tax funding arrangement and a tax sharing agreement with the head entity. Under the tax funding agreement, Woodside Petroleum Ltd and each of the entities in the tax consolidated group have agreed to pay or receive a tax equivalent payment to or from the head entity, based on the current tax liability or current tax asset of the entity.

The tax sharing agreement entered into between members of the tax consolidated group provides for the determination of the allocation of income tax liabilities between the entities, should the head entity default on its tax payment obligations. No amounts have been recognised in the financial statements in respect of this agreement as payment of any amounts under the tax sharing agreement is considered remote.

(b) New and amended accounting standards and interpretations issued but not yet effective

A number of new standards, amendments of standards and interpretations have recently been issued but are not yet effective and have not been adopted by the Group as at the financial reporting date.

The Group has reviewed these standards and interpretations and has determined that none of the new or amended standards will significantly affect the Group's accounting policies, financial position or performance.

(c) New and amended accounting standards and interpretations adopted

The Group adopted AASB 2020-8 *Amendments to Australian Accounting Standards – Interest Rate Benchmark Reform* as of 1 January 2021.

The amendments provide temporary reliefs which address the financial reporting effects when an interbank offered rate (IBOR) is replaced with an alternative nearly risk-free interest rate (RFR). The amendments include the following practical expedients:

- practical expedients when accounting for changes in the basis for determining the contractual cash flows of financial assets and liabilities;
- reliefs from discontinuing hedge relationships;
- temporary relief from having to meet the separately identifiable requirement when a RFR instrument is designated as a hedge of a risk component; and
- additional AASB 7 - *Financial Instruments* disclosures.

These amendments did not impact the financial statements of the Group other than additional required disclosures (refer to Note D.6). The Group intends to use the practical expedients in future periods when existing IBORs are replaced by RFRs.

A number of other new standards are also effective from 1 January 2021 but they do not have a material effect on the Group's financial statements.

DIRECTORS' DECLARATION

In accordance with a resolution of directors of Woodside Petroleum Ltd, we state that:

1. In the opinion of the directors:
   (a) the financial statements and notes thereto, and the disclosures included in the audited 2021 Remuneration Report, comply with Australian Accounting Standards and the *Corporations Act 2001*;
   (b) the financial statements and notes thereto give a true and fair view of the financial position of the Group as at 31 December 2021 and of the performance of the Group for the financial year ended 31 December 2021;
   (c) the financial statements and notes thereto also comply with International Financial Reporting Standards as disclosed in the 'About these statements' section within the notes to the 2021 Financial Statements;
   (d) there are reasonable grounds to believe that the company will be able to pay its debts as and when they become due and payable; and
   (e) there are reasonable grounds to believe that the members of the Closed Group identified in Note E.8 will be able to meet any obligations or liabilities which they are or may become subject to, by virtue of the Deed of Cross Guarantee.
2. This declaration has been made after receiving the declarations required to be made to the directors in accordance with section 295A of the *Corporations Act 2001* for the year ended 31 December 2021.

For and on behalf of the Board

R J Goyder, AO
Chairman
Perth, Western Australia
17 February 2022

M E O'Neill
Chief Executive Officer and Managing Director
Perth, Western Australia
17 February 2022

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Independent auditor's report to the members of Woodside Petroleum Ltd

Report on the audit of the financial report

Opinion

We have audited the financial report of Woodside Petroleum Ltd (the Company) and its subsidiaries (collectively the Group), which comprises the consolidated statement of financial position as at 31 December 2021, the consolidated income statement, the consolidated statement of comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, notes to the financial statements, including a summary of significant accounting policies, and the directors' declaration.

In our opinion, the accompanying financial report of the Group is in accordance with the Corporations Act 2001, including:

a) giving a true and fair view of the Group's financial position as at 31 December 2021 and of its financial performance for the year ended on that date.

b) complying with Australian Accounting Standards and the Corporations Regulations 2001.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the financial report section of our report. We are independent of the Group in accordance with the auditor independence requirements of the Corporations Act 2001 and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 Code of Ethics for Professional Accountants (including Independence Standards) (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial report of the current year. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, but we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

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We have fulfilled the responsibilities described in the Auditor's responsibilities for the audit of the financial report section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the financial report. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying financial report.

1. Restoration obligations

Why significant	How our audit addressed the key audit matter
At 31 December 2021, the Group has recognised provisions for restoration obligations relating to onshore and offshore assets of $2,218 million. As disclosed in Note D.5, the calculation of restoration provisions is conducted by specialist engineers and requires judgemental assumptions to be made by the Group regarding removal date, compliance with environmental legislation and regulations, the extent of restoration activities required, the engineering methodology for estimating cost, future removal technologies in determining the removal cost, and liability-specific discount rates to determine the present value of these cash flows. The judgements and estimates in respect of restoration provisions are based on conditions existing at 31 December 2021 including key assumptions related to certain items composed of steel, or steel and concrete, with hydrocarbons removed remaining in-situ. Australian regulator approval for these items remaining in-situ will only be provided towards the end of field life and accordingly at 31 December 2021, there is uncertainty whether the Australian regulator will approve plans for these items to be decommissioned in-situ. Significant assumptions and estimates outlined above are inherently subjective. Changes in these assumptions can lead to significant changes in the restoration provision. In this context, the disclosures in the financial report provide particularly important information about the assumptions made in the calculation of the restoration provision and uncertainties at 31 December 2021. As a result, we consider the restoration provision calculation and the related disclosures in the financial report to be a key audit matter. For the same reasons, we consider it important to draw attention to the information in Note D.5.	We assessed the restoration obligation provisions prepared by the Group, evaluating the assumptions and methodologies used and the estimates made. Our audit procedures included the following: ► evaluating the Group's process for identifying legal and regulatory obligations for restoration and testing the completeness of operating locations included in the restoration provision and the completeness and accuracy of data used within the Group's estimates; ► in conjunction with our environmental specialists, we evaluated the restoration cost estimates based on the relevant current legal and regulatory requirements; ► compared current year cost estimates to those of the prior year and considered management's explanations where these changed; ► compared the timing of the future cash outflows against the anticipated end of field life, cross-checking these dates were consistent to the Group's reserves estimates and impairment calculations; ► evaluated the appropriateness of the discount rates used to calculate the present value of the provision; ► evaluated the appropriateness of management's methodology for estimating future costs. For a sample of locations within the Group, we assessed the reasonableness of key assumptions in the estimation of future costs; ► assessed the competence, capability and objectivity of the Group's internal experts used in the determination of the restoration provision; ► tested the mathematical accuracy of the restoration provision calculations and the sensitivity analysis. We also considered the adequacy and completeness of the financial report disclosure of the assumptions, key estimates and judgements applied by the Group.

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2. Carrying value of oil and gas properties

Why significant	How our audit addressed the key audit matter
Australian Accounting Standards require an entity to assess throughout the reporting period whether there is any indication that an asset may be impaired, or that reversal of a previously recognised impairment may be required. If any such indication exists, an entity shall estimate the recoverable amount of the asset. At 31 December 2021, the Group concluded that there were impairment/impairment reversal indicators for the Pluto-Scarborough, NWS Gas, NWS Oil and Wheatstone cash generating units (CGUs). Impairment testing was undertaken as outlined in Note B.4, resulting in an impairment reversal of $1,058 million relating to Pluto-Scarborough and NWS Gas CGUs. No impairment/impairment reversal was recognised in respect to the NWS Oil and Wheatstone CGUs. Key assumptions, judgements and estimates, used in the formulation of the Group's impairment testing of the oil and gas properties are disclosed in Note B.4. The assessment of indicators of impairment and reversal of impairment and the impairment testing process are complex and highly judgemental and are based on assumptions which are impacted by expected future performance and market conditions. Accordingly, this matter was considered to be a key audit matter.	We evaluated the Group's consideration of internal and external sources of information in assessing whether indicators of impairment or reversal of impairment existed. Where impairment or impairment reversal indicators were present and impairment testing was conducted by the Group, we evaluated the assumptions and methodologies used by the Group and the estimates made in conducting this testing. In particular, we considered those judgements and estimates related to the determination of CGUs, the forecast cash flows and the inputs used to formulate those cash flows such as commodity prices, discount rates, reserves, inflation rates, operating costs and foreign exchange rates. We involved our valuations, modelling and economics specialists to assist in the impairment assessment for the audit. Our audit procedures were undertaken across the CGUs for which impairment and impairment reversal indicators were identified. Specifically, we evaluated the discounted cash flow models and other data supporting the Group's assessment. In doing so, we: ► considered future production profiles compared to reserves, current approved budgets and historical production, and tested variations were in accordance with our expectations based upon other information obtained throughout the audit; ► evaluated commodity prices with reference to contractual arrangements, market prices (where available), broker consensus, analyst views and historical performance; ► evaluated discount rates, inflation rates and foreign exchange rates with reference to market prices (where available), market indices, broker consensus and historical performance; ► compared future operating and development expenditure to current sanctioned budgets, historical expenditure and tested variations were in accordance with our expectations based upon other information obtained throughout the audit; ► evaluated how the Group's response to climate risk has been reflected in the assessment of the recoverable amount of the CGUs; ► assessed whether the reversal of impairment charge recorded in the financial statements agreed to the underlying impairment testing models; ► assessed the impact of changes to key assumptions on the recoverable amount of the CGUs; and ► tested the mathematical accuracy of the discounted cash flow models and the sensitivity analysis. We reviewed the calculation of the extent of the original cost impaired adjusted for depreciation for the Pluto-Scarborough and NWS Gas CGUs at 31 December 2021 to test the amount recorded did not exceed the carrying value of the CGU if the prior year impairments were not initially recorded.

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Why significant	How our audit addressed the key audit matter
	We used the work of the Group's internal experts with respect to the hydrocarbon reserve estimates used in the Group's impairment testing. This included understanding the reserve estimation processes carried out, the Group's internal certification process for technical and commercial experts who are responsible for reserves, the design of the Group's Petroleum Resources Management procedures and its alignment with the guidelines prepared by the Society of Petroleum Engineers. We also examined the competence and objectivity of the Group's internal and external experts and the scope and appropriateness of their work. We involved our oil and gas reserves engineering specialists in the assessment of the reserves estimation methodology and to test significant revisions. We also considered the adequacy of the financial report disclosures regarding the assumptions, key estimates and judgements applied by management for the Group's impairment assessments, and in respect of sensitivity analysis disclosed. These disclosures are included in Note B.4.

Information other than the financial report and auditor's report thereon

The directors are responsible for the other information. The other information comprises the information included in the Company's Annual Report for the year ended 31 December 2021, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon, with the exception of the Remuneration Report and our related assurance opinion.

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

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

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the Corporations Act 2001 and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters relating to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

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Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

As part of an audit in accordance with the Australian Auditing Standards, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.
- Conclude on the appropriateness of the directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial report or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial report, including the disclosures, and whether the financial report represents the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

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From the matters communicated to the directors, we determine those matters that were of most significance in the audit of the financial report of the current year and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on the audit of the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 73 to 92 of the directors' report for the year ended 31 December 2021.

In our opinion, the Remuneration Report of Woodside Petroleum Ltd for the year ended 31 December 2021, complies with section 300A of the Corporations Act 2001.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the Corporations Act 2001. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.

Ernst & Young

Robert A Kirkby
Partner
Perth
17 February 2022

CONTENTS

Significant changes in the current reporting period

The financial performance and position of the Group were particularly affected by the following events and transactions during the reporting period:

- In January 2020, the Group took unconditional FID on Sangomar Field Development Phase 1. Exploration and evaluation assets were transferred to oil and gas properties (refer to Notes B.2 and B.3).
- In January 2020, the Group completed a $600 million syndicated facility with a term of seven years (refer to Note C.2).
- In August 2020, the Group exercised its right to pre-empt the sale of Capricorn Senegal Limited's interest in the Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore (RSSD) Joint Venture. The transaction was completed on 22 December 2020. In December 2020, the Group also exercised its right to pre-empt the sale of FAR Senegal RSSD SA's interest in the RSSD Joint Venture (refer to Note B.5).
- The COVID-19 outbreak was declared a pandemic by the World Health Organisation in March 2020. The outbreak and the response of Governments in dealing with the pandemic has affected general activity levels within the global community, economy and business operations. The COVID-19 crisis and a decline in oil prices have impacted and will continue to impact the Group's earnings, cash flow and financial position. The financial statements have been prepared based on assumptions and conditions prevalent as at 31 December 2020. Given ongoing economic uncertainty, these assumptions could change in the future. Key impacts in the reporting period are:
  - The decline in forecast prices, weaker demand and ongoing uncertainties, resulted in impairment losses (pre-tax) of $5,269 million (refer to Note B.4) and recognition of an onerous contract provision of $447 million (refer to Note D
  - The decline in long-term government bond rates increased restoration liabilities by $173 million (refer to Note D.5); and
  - The Group hedged a percentage of its exposure to commodity price risk through several commodity swaps and call option derivative financial instruments (refer to Note D.6).

CONSOLIDATED INCOME STATEMENT

for the year ended 31 December 2020

	Notes	2020 US$m	2019 US$m
Operating revenue	A.1	3,600	4,873
Cost of sales	A.1	(2,985)	(2,727)
Gross profit		615	2,146
Other income	A.1	31	100
Other expenses	A.1	(5,817)	(1,155)
Profit/(loss) before tax and net finance costs		(5,171)	1,091
Finance income		58	91
Finance costs	A.2	(327)	(320)
Profit/(loss) before tax		(5,440)	862
Petroleum resource rent tax (PRRT) benefit	A.5	439	31
Income tax benefit/(expense)	A.5	1,026	(511)
Profit/(loss) after tax		(3,975)	382
Profit/(loss) attributable to:			
Equity holders of the parent		(4,028)	343
Non-controlling interest	E.8	53	39
Profit/(loss) for the period		(3,975)	382
Basic and diluted earnings/(losses) per share attributable to equity holders of the parent (US cents)	A.4	(423.5)	36.7

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

for the year ended 31 December 2020

	2020 US$m	2019 US$m
Profit/(loss) for the period	(3,975)	382
Other comprehensive income/(loss)		
Items that may be reclassified to the income statement in subsequent periods:		
Gains/(losses) on hedges	(59)	2
Items that will not be reclassified to the income statement in subsequent periods:		
Remeasurement gains on defined benefit plan	2	2
Other comprehensive income/(loss) for the period, net of tax	(57)	4
Total comprehensive income/(loss) for the period	(4,032)	386
Total comprehensive income/(loss) attributable to:		
Equity holders of the parent	(4,085)	347
Non-controlling interest	53	39
Total comprehensive income/(loss) for the period	(4,032)	386

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

as at 31 December 2020

	Notes	2020 US$m	2019 US$m
Current assets			
Cash and cash equivalents	C.1	3,604	4,058
Receivables	D.2	303	343
Inventories	D.3	125	176
Other financial assets	D.6	172	28
Other assets		48	42
Total current assets		4,252	4,647
Non-current assets			
Receivables	D.2	423	245
Inventories	D.3	40	-
Other financial assets	D.6	54	35
Other assets		55	21
Exploration and evaluation assets	B.2	2,045	3,809
Oil and gas properties	B.3	15,267	18,298
Other plant and equipment		199	177
Deferred tax assets	A.5	1,304	1,173
Lease assets	D.7	984	948
Total non-current assets		20,371	24,706
Total assets		24,623	29,353
Current liabilities			
Payables	D.4	505	581
Interest-bearing liabilities	C.2	776	77
Other financial liabilities	D.6	37	12
Other liabilities		136	34
Provisions	D.5	500	272
Tax payable	A.5	46	86
Lease liabilities	D.7	94	69
Total current liabilities		2,094	1,131
Non-current liabilities			
Interest-bearing liabilities	C.2	5,438	5,602
Deferred tax liabilities	A.5	549	2,193
Other financial liabilities	D.6	34	15
Other liabilities		42	46
Provisions	D.5	2,407	1,856
Lease liabilities	D.7	1,184	1,101
Total non-current liabilities		9,654	10,813
Total liabilities		11,748	11,944
Net assets		12,875	17,409
Equity			
Issued and fully paid shares	C.3	9,297	9,010
Shares reserved for employee share plans	C.3	(23)	(39)
Other reserves	C.4	1,403	992
Retained earnings		1,398	6,654
Equity attributable to equity holders of the parent		12,075	16,617
Non-controlling interest	E.8	800	792
Total equity		12,875	17,409

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF CASHFLOWS

for the year ended 31 December 2020

	Notes	2020 US$m	2019 US$m
Cash flows from operating activities			
Profit/(loss) after tax for the period		(3,975)	382
Adjustments for:			
Non-cash items			
Depreciation and amortisation		1,730	1,617
Depreciation of lease assets		94	86
Change in fair value of derivative financial instruments		31	(1)
Net finance costs		269	229
Tax (benefit)/expense		(1,465)	480
Exploration and evaluation written off		2	46
Impairment losses		5,269	737
Restoration		28	77
Onerous contract provision		347	-
Other		(12)	39
Changes in assets and liabilities			
Decrease in trade and other receivables		41	118
Decrease/(increase) in inventories		51	(21)
Increase in provisions		155	33
Increase in lease liabilities		40	-
Increase in other assets and liabilities		(137)	(48)
Decrease in trade and other payables		(121)	(11)
Cash generated from operations		2,347	3,763
Purchases of shares and payments relating to employee share plans		(32)	(66)
Interest received		64	85
Dividends received		4	5
Borrowing costs relating to operating activities		(180)	(157)
Income tax paid		(331)	(313)
Payments for restoration		(23)	(12)
Net cash from operating activities		1,849	3,305
Cash flows used in investing activities			
Payments for capital and exploration expenditure		(1,418)	(1,213)
Proceeds from disposal of non-current assets held for sale		-	12
Borrowing costs relating to investing activities		(57)	(37)
Advances to other external entities		(110)	-
Payments for acquisition of joint arrangements	B.5	(527)	-
Net cash used in investing activities		(2,112)	(1,238)
Cash flows (used in)/from financing activities			
Proceeds from borrowings	C.2	600	1,700
Repayment of borrowings	C.2	(83)	(84)
Borrowing costs relating to financing activities		(21)	(30)
Repayment of lease liabilities		(71)	(41)
Borrowing costs relating to lease liabilities		(86)	(89)
Contributions to non-controlling interests		(111)	(77)
Dividends paid (outside of DRP)		-	(852)
Dividends paid (net of DRP)		(454)	(210)
Net proceeds from share issuance		23	-
Net cash (used in)/from financing activities		(203)	317
Net (decrease)/increase in cash held		(466)	2,384
Cash and cash equivalents at the beginning of the period		4,058	1,674
Effects of exchange rate changes		12	-
Cash and cash equivalents at the end of the period	C.1	3,604	4,058

The accompanying notes form part of the Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

for the year ended 31 December 2020

	Issued and fully paid shares	Shares reserved for employee share plans	Employee benefits reserve	Foreign currency translation reserve	Hedging reserve	Distributable profits reserve	Retained earnings	Equity holders of the parent	Non-controlling interest	Total equity
Notes	C.3	C.3	C.4	C.4	C.4	C.4			E.8	
	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m
At 1 January 2020	9,010	(39)	211	793	(12)	-	6,654	16,617	792	17,409
Transfers	-	-	-	-	-	710	(710)	-	-	-
Profit/(loss) for the period	-	-	-	-	-	-	(4,028)	(4,028)	53	(3,975)
Other comprehensive income/(loss)	-	-	2	-	(59)	-	-	(57)	-	(57)
Total comprehensive income/(loss) for the period	-	-	2	-	(59)	-	(4,028)	(4,085)	53	(4,032)
Dividend Reinvestment Plan	264	-	-	-	-	-	-	264	-	264
Shares issued	23	-	-	-	-	-	-	23	-	23
Employee share plan purchases	-	(32)	-	-	-	-	-	(32)	-	(32)
Employee share plan redemptions	-	48	(48)	-	-	-	-	-	-	-
Share-based payments (net of tax)	-	-	54	-	-	-	-	54	-	54
Dividends paid	-	-	-	-	-	(248)	(518)	(766)	(45)	(811)
At 31 December 2020	9,297	(23)	219	793	(71)	462	1,398	12,075	800	12,875
At 1 January 2019	8,880	(31)	206	793	(14)	-	7,500	17,334	833	18,167
Profit for the period	-	-	-	-	-	-	343	343	39	382
Other comprehensive income	-	-	2	-	2	-	-	4	-	4
Total comprehensive income for the period	-	-	2	-	2	-	343	347	39	386
Dividend Reinvestment Plan	130	-	-	-	-	-	-	130	-	130
Employee share plan purchases	-	(66)	-	-	-	-	-	(66)	-	(66)
Employee share plan redemptions	-	58	(58)	-	-	-	-	-	-	-
Share-based payments (net of tax)	-	-	61	-	-	-	-	61	-	61
Dividends paid	-	-	-	-	-	-	(1,189)	(1,189)	(80)	(1,269)
At 31 December 2019	9,010	(39)	211	793	(12)	-	6,654	16,617	792	17,409

The accompanying notes form part of the Financial Statements.

NOTES TO THE FINANCIAL STATEMENTS

for the year ended 31 December 2020

About these statements

Woodside Petroleum Ltd (Woodside or the Group) is a for-profit entity limited by shares, incorporated and domiciled in Australia. Its shares are publicly traded on the Australian Securities Exchange. The nature of the operations and the principal activities of the Group are described in the Directors' Report and in the segment information in Note A.1.

The financial statements were authorised for issue in accordance with a resolution of the directors on 18 February 2021.

Statement of compliance

The financial statements are general purpose financial statements, which have been prepared in accordance with the requirements of the *Corporations Act 2001*, Australian Accounting Standards (AASBs) and other authoritative pronouncements of the Australian Accounting Standards Board. The financial statements comply with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

The accounting policies are consistent with those disclosed in the 2019 Financial Statements, except for the impact of all new or amended standards and interpretations adopted with effect from 1 January 2020. The adoption of these standards and interpretations did not result in any significant changes to the Group's accounting policies, with the exception of AASB 2018-6 *Amendments to Australian Accounting Standards - Definition of a Business* (refer to Note E.9(c)).

The Group early adopted AASB 2019-3 *Amendments to Australian Accounting Standards - Interest Rate Benchmark Reform* (AASB 2019-3) in the prior year, effective from 1 January 2019.

Currency

The functional and presentation currency of Woodside Petroleum Ltd and all its subsidiaries is the US dollar.

Transactions in foreign currencies are initially recorded in the functional currency of the transacting entity at the exchange rates ruling at the date of transaction. Monetary assets and liabilities denominated in foreign currencies at the reporting date are translated at the rates of exchange ruling at that date. Exchange differences in the consolidated financial statements are taken to the income statement.

Rounding of amounts

The amounts contained in these financial statements have been rounded to the nearest million dollars under the option available to the Group under Australian Securities and Investments Commission (ASIC) Corporations (Rounding in Financial/Directors' Reports) Instrument 2016/191 dated 24 March 2016, unless otherwise stated.

Basis of preparation

The financial statements have been prepared on a historical cost basis, except for derivative financial instruments and certain other financial assets and financial liabilities, which have been measured at fair value or amortised cost adjusted for changes in fair value attributable to the risks that are being hedged in effective hedge relationships.

If the carrying value of financial assets and financial liabilities does not approximate their fair value, the fair value has been included in the notes to the financial statements.

The financial statements comprise the financial results of the Group as at 31 December each year (refer to Note E.8).

Subsidiaries are fully consolidated from the date on which control is obtained by the Group and cease to be consolidated from the date at which the Group ceases to have control.

The financial statements of subsidiaries are prepared for the same reporting period as the parent company, using consistent accounting policies. All intercompany balances and transactions, including unrealised profits and losses arising from intra-group transactions, have been eliminated in full.

The consolidated financial statements provide comparative information in respect of the previous period. Where required, a reclassification of items in the financial statements of the previous period has been made in accordance with the classification of items in the financial statements of the current period.

Non-controlling interests are allocated their share of the net profit after tax in the consolidated income statement and their share of other comprehensive income net of tax in the consolidated statement of comprehensive income, and are presented within equity in the consolidated statement of financial position, separately from parent shareholders' equity.

Financial and capital risk management

The Board of Directors has overall responsibility for the establishment and oversight of the Group's risk management framework, including review and approval of the Group's risk management strategy, policy and key risk parameters. The Board of Directors and the Audit and Risk Committee have oversight of the Group's internal control system and risk management process, including oversight of the internal audit function.

The Group's management of financial and capital risks is aimed at ensuring that available capital, funding and cash flows are sufficient to:

- meet the Group's financial commitments as and when they fall due;
- maintain the capacity to fund its committed project developments;
- pay a reasonable dividend; and
- maintain a long-term credit rating of not less than 'investment grade'.

The Group monitors and tests its forecast financial position against these criteria and, in general, will undertake hedging activity only when necessary to ensure that these objectives are achieved.

Other circumstances that may lead to hedging activities include the management of exposures relating to trading activities and the underpinning of the economics of a new project. It is, and has been throughout the period, the Group Treasury policy that no speculative trading in financial instruments shall be undertaken. Refer to the Risk section of Corporate on pages 38-41 for more information on the Group's objectives, policies and processes for managing financial risk.

The below risks arise in the normal course of the Group's business. Risk information can be found in the following sections:

Section A	Commodity price risk	Page 91
Section A	Foreign exchange risk	Page 91
Section C	Capital risk	Page 105
Section C	Liquidity risk	Page 105
Section C	Interest rate risk	Page 105
Section D	Credit risk	Page 109

Key estimates and judgements

In applying the Group's accounting policies, management continually evaluates judgements, estimates and assumptions based on experience and other factors, including expectations of future events that may have an impact on the Group. All judgements, estimates and assumptions made are believed to be reasonable based on the most current set of circumstances known to management, and actual results may differ. Significant judgements, estimates and assumptions made by management in the preparation of these financial statements are found in the following notes:

Note A.1	Revenue from contracts with customers	Page 92
Note A.5	Taxes	Page 96
Note B.2	Exploration and evaluation	Page 99
Note B.3	Oil and gas properties	Page 100
Note B.4	Impairment of exploration and evaluation and oil and gas properties	Page 103
Note D.5	Provisions	Page 112
Note D.6	Other financial assets and liabilities	Page 113
Note D.7	Leases	Page 114
Note E.6	Joint arrangements	Page 118

In this section

This section addresses financial performance of the Group for the reporting period including, where applicable, the accounting policies applied and the key estimates and judgements made. This section also includes the tax position of the Group for and at the end of the reporting period.

Key financial and capital risks in this section

Commodity price risk management

The Group's revenue is exposed to commodity price fluctuations. Commodity price risks are measured by monitoring and stress testing the Group's forecast financial position to sustained periods of low oil and gas prices. This analysis is regularly performed on the Group's portfolio and, as required, for discrete projects and acquisitions.

As at the reporting date, the Group had no financial instruments with material exposure to commodity price risk.

Foreign exchange risk management

Foreign exchange risk arises from future commitments, financial assets and financial liabilities that are not denominated in US dollars. The majority of the Group's revenue is denominated in US dollars. The Group is exposed to foreign currency risk arising from operating and capital expenditure incurred in currencies other than US dollars, particularly Australian dollars.

Measuring the exposure to foreign exchange risk is achieved by regularly monitoring and performing sensitivity analysis on the Group's financial position.

A reasonably possible change in the exchange rate of the US dollar to the Australian dollar (+12%/-12% (2019: +12%/-12%)), with all other variables held constant, would not have a material impact on the Group's equity or the profit or loss in the current period. Refer to Notes C1, C2, D2, D4 and D7 for details of the denominations of cash and cash equivalents, interest-bearing liabilities, receivables, payables and lease liabilities held at 31 December 2020.

In order to hedge the foreign exchange risk and interest rate risk (refer to Section C) of a Swiss Franc (CHF) denominated medium term note, Woodside holds a number of cross-currency interest rate swaps (refer to Note C.2 and D.6). The aim of this hedge is to convert the fixed interest CHF bond into variable interest US dollar debt.

A.1 Segment revenue and expenses

Operating segment information

The Group has identified its operating segments based on the internal reports that are reviewed and used by the executive management team in assessing performance and in determining the allocation of resources.

The operating segments are consistent with the 2019 Financial Statements. In the period, the following changes were made to information presented to the executive management team and 2019 amounts have been restated:

- Revenue from sale of hydrocarbons – the Group changed the presentation of LNG revenue to align with the marketing and sale of LNG on a portfolio basis. LNG revenue includes the sale of produced and purchased LNG and is measured for each segment at the average realised price of all LNG sold. The sale of purchased LNG was previously classified as trading revenue or other hydrocarbon revenue.
- Shipping and other revenue – was previously classified as trading revenue.

Management monitors the performance of the operating results of the segments separately for the purpose of making decisions about resource allocation and performance assessment. The performance of operating segments is evaluated based on profit before tax and net finance costs and is measured in accordance with the Group's accounting policies.

Financing requirements, including cash and debt balances, finance income, finance costs and taxes are managed at a Group level.

Operating segments outlined below are identified by management based on the nature and geographical location of the business or venture.

Producing

North West Shelf Project – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas, condensate and liquefied petroleum gas in assigned permit areas.

Pluto LNG – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas and condensate in assigned permit areas.

Australia Oil – Exploration, evaluation, development, production and sale of crude oil in assigned permit areas (North West Shelf, Greater Enfield and Vincent).

Wheatstone – Exploration, evaluation, development, production and sale of liquefied natural gas, pipeline natural gas and condensate in assigned permit areas.

Development

Development segments – This segment comprises exploration, evaluation and development of liquefied natural gas, crude oil and condensate in the Browse, Scarborough, Kitimat, Sunrise and Sangomar projects.

Other

Other segments – This segment comprises trading and shipping activities and activities undertaken in other international locations.

Unallocated items – Unallocated items comprise primarily corporate non-segmental items of revenue and expenses and associated assets and liabilities not allocated to operating segments as they are not considered part of the core operations of any segment.

Major customer information

The Group has two major customers which account for 15% and 13% of the Group's external revenue. The sales are generated by the Pluto and North West Shelf operating segments (2019: three customers; 16%, 15% and 11% generated by Pluto, North West Shelf and Wheatstone).

Geographic information	Revenue from external customers[1]		Non-current assets[2]	
	2020 US$m	2019 US$m	2020 US$m	2019 US$m
Oceania	286	202	17,559	21,934
Asia	3,076	4,435	229	199
Canada	-	2	34	777
Africa	-	-	1,244	621
Other	238	234	1	2
Consolidated	3,600	4,873	19,067	23,533

1. Revenue is attributable to geographic region based on the location of the customer.
2. Non-current assets exclude deferred tax of $1,304 million (2019: $1,173 million).

Recognition and measurement

Revenue from contracts with customers

Revenue is recognised when or as the Group transfers control of products or provides services to a customer at the amount to which the Group expects to be entitled. If the consideration includes a variable component, the Group estimates the amount of the expected consideration receivable. Variable consideration is estimated throughout the contract and is constrained until it is highly probable a significant revenue reversal in the amount of cumulative revenue recognised will not occur.

- Revenue from sale of hydrocarbons - Revenue from the sale of hydrocarbons is recognised at a point in time when control of the product is transferred to the customer, which is typically on delivery. Revenue from take or pay contracts is recorded as unearned revenue until the product has been drawn by the customer (transfer of control), at which time it is recognised in earnings.
- Other operating revenue - Revenue earned from LNG processing and other services is recognised over time as the services are rendered.

Expenses

- Royalties and excise duty - Royalties and excise duty under existing regimes are considered to be production-based taxes and are therefore accrued on the basis of the Group's entitlement to physical production.
- Depreciation and amortisation - Refer to Note B.3 for details on depreciation and amortisation.
- Impairment - Refer to Note B.4 for details on impairment.
- Leases - Refer to Note D.7 for details on leases.
- Employee benefits - Refer to Note E.2 for details.

Key estimates and judgements

Revenue from contracts with customers

Judgement is required to determine the point at which the customer obtains control of hydrocarbons. Factors including transfer of legal title, transfer of significant risks and rewards of ownership and the existence of a present right to payment for the hydrocarbons typically result in control transferring on delivery of hydrocarbons at port of loading or port of discharge.

The transaction price at the date control passes for sales made subject to provisional pricing periods in oil and condensate contracts is determined with reference to quoted commodity prices.

Judgement is also used to determine if it is probable that a significant reversal will occur in relation to revenue recognised during open pricing periods in LNG contracts. The Group estimates variable consideration based on reasonably available information from contract negotiations and market indicators.

Progress of performance obligations for LNG processing services revenue recognised over time is measured using the output method which most accurately measures the progress towards satisfaction of the performance obligation of the services provided.

A.1 Segment revenue and expenses (cont.)

	Producing								Development		Other					
	North West Shelf		Pluto		Australia Oil		Wheatstone		Development		Other segments		Unallocated items		Consolidated	
	2020 US$m	2019[1] US$m	2020 US$m	2019[1] US$m	2020 US$m	2019[1] US$m	2020 US$m	2019[1] US$m	2020 US$m	2019[1] US$m	2020 US$m	2019[1] US$m	2020 US$m	2019[1] US$m	2020 US$m	2019[1] US$m
Liquefied natural gas[2]	722	1,102	1,320	1,753	-	-	365	572	-	-	112	237	-	-	2,519	3,664
Domestic gas	44	69	11	4	-	-	18	10	-	2	-	-	-	-	73	85
Condensate	194	271	114	188	-	-	103	127	-	-	-	-	-	-	411	586
Oil	-	-	-	-	432	360	-	-	-	-	-	-	-	-	432	360
Liquefied petroleum gas	16	44	-	-	-	-	-	-	-	-	-	-	-	-	16	44
Revenue from sale of hydrocarbons	976	1,486	1,445	1,945	432	360	486	709	-	2	112	237	-	-	3,451	4,739
Processing and services revenue	-	-	142	119	-	-	-	-	-	-	-	-	-	-	142	119
Shipping and other revenue	-	-	-	-	-	-	-	-	-	-	7	15	-	-	7	15
Other revenue	-	-	142	119	-	-	-	-	-	-	7	15	-	-	149	134
Operating revenue from contracts with customers	976	1,486	1,587	2,064	432	360	486	709	-	2	119	252	-	-	3,600	4,873
Production costs	(118)	(132)	(189)	(225)	(107)	(87)	(72)	(62)	-	(2)	-	-	8	3	(478)	(505)
Royalties and excise	(79)	(187)	-	-	(3)	(6)	-	-	-	-	-	-	-	-	(82)	(193)
Insurance	(7)	(6)	(19)	(13)	(3)	(2)	(3)	(1)	-	-	-	-	1	5	(31)	(17)
Inventory movement	(1)	(1)	(7)	6	(21)	23	(3)	1	-	-	-	-	-	-	(32)	29
Costs of production	(205)	(326)	(215)	(232)	(134)	(72)	(78)	(62)	-	(2)	-	-	9	8	(623)	(686)
Land and buildings	(4)	(4)	(27)	(24)	-	-	(24)	(29)	-	-	-	-	-	-	(55)	(57)
Transferred exploration and evaluation	(13)	(17)	(32)	(36)	(32)	(22)	(22)	(26)	-	-	-	-	-	-	(99)	(101)
Plant and equipment	(228)	(243)	(823)	(755)	(251)	(148)	(231)	(266)	-	-	-	-	-	-	(1,533)	(1,412)
Marine vessels and carriers	(2)	(4)	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(4)
Oil and gas properties depreciation and amortisation	(247)	(268)	(882)	(815)	(283)	(170)	(277)	(321)	-	-	-	-	-	-	(1,689)	(1,574)
Shipping and direct sales costs	(49)	(56)	(53)	(44)	-	-	(44)	(36)	-	-	35	26	-	-	(111)	(110)
Trading costs[3]	(8)	(27)	(49)	(98)	-	-	(10)	(4)	-	-	(144)	(120)	-	-	(211)	(249)
Other hydrocarbon costs	-	-	-	(48)	-	-	(4)	(60)	-	-	-	-	-	-	(4)	(108)
Movement in onerous contract provision[4]	-	-	-	-	-	-	-	-	-	-	(347)	-	-	-	(347)	-
Other cost of sales	(57)	(83)	(102)	(190)	-	-	(58)	(100)	-	-	(456)	(94)	-	-	(673)	(467)
Cost of sales	(509)	(677)	(1,199)	(1,237)	(417)	(242)	(413)	(483)	-	(2)	(456)	(94)	9	8	(2,985)	(2,727)
Gross profit	467	809	388	827	15	118	73	226	-	-	(337)	158	9	8	615	2,146
Other income[5]	13	10	3	2	-	-	12	81	-	2	1	-	2	5	31	100
Exploration and evaluation expenditure	(3)	(4)	(1)	(2)	(1)	(3)	(3)	(1)	(3)	(4)	(56)	(89)	-	-	(67)	(103)
Amortisation	-	-	-	-	-	-	-	-	-	-	(12)	(15)	-	-	(12)	(15)
Write-offs	-	(4)	-	-	-	-	-	-	-	-	(2)	(42)	-	-	(2)	(46)
Exploration and evaluation	(3)	(8)	(1)	(2)	(1)	(3)	(3)	(1)	(3)	(4)	(70)	(146)	-	-	(81)	(164)
General, administrative and other costs	(1)	7	(1)	-	(1)	(8)	(1)	-	(14)	(1)	(6)	3	(166)	(81)	(190)	(80)
Depreciation of other plant and equipment	-	-	-	-	-	-	-	-	-	-	-	-	(29)	(28)	(29)	(28)
Depreciation of lease assets	-	-	(26)	(26)	-	-	-	-	-	-	(34)	(31)	(34)	(29)	(94)	(86)
Restoration movement	(5)	3	-	-	(62)	(80)	-	-	39	-	-	-	-	-	(28)	(77)
Impairment losses[6]	(454)	(17)	(1,291)	-	(674)	-	(1,401)	-	(1,298)	(720)	(151)	-	-	-	(5,269)	(737)
Other[5]	(16)	2	3	(4)	(12)	8	(3)	24	(4)	(5)	(1)	-	(93)	(8)	(126)	17
Other costs	(476)	(5)	(1,315)	(30)	(749)	(80)	(1,405)	24	(1,277)	(726)	(192)	(28)	(322)	(146)	(5,736)	(991)
Other expenses	(479)	(13)	(1,316)	(32)	(750)	(83)	(1,408)	23	(1,280)	(730)	(262)	(174)	(322)	(146)	(5,817)	(1,155)
Profit/(loss) before tax and net finance costs	1	806	(925)	797	(735)	35	(1,323)	330	(1,280)	(728)	(598)	(16)	(311)	(133)	(5,171)	1,091

1. 2019 amounts have been restated for the application of reporting on a LNG portfolio basis as detailed in 'Operating segment information'.
2. Includes an adjustment of $113 million related to price reviews currently under negotiation for multiple contracts across North West Shelf and Pluto, reducing revenue recognised in the current and prior periods and increasing other liabilities.
3. Trading costs includes trading intersegment adjustments which eliminate to nil in the Group's consolidated results.
4. Comprises new provisions recognised of $447 million, offset by changes in estimates of $54 million, provisions used of $41 million and a revision of discount rates of $5 million. Refer to Note D.5 for more details.
5. Other comprises foreign exchange gains and losses, gains and losses on hedging activities, and other expenses not associated with the ongoing operations of the business.
6. Impairment losses represent charges on exploration and evaluation of $1,557 million and oil and gas properties of $3,712 million. Refer to Note B.4 for further details.

A.2 Finance costs

	2020 US$m	2019 US$m
Interest on interest-bearing liabilities	237	215
Interest on lease liabilities	86	89
Accretion charge	32	40
Other finance costs	29	17
Less: Finance costs capitalised against qualifying assets	(57)	(41)
	327	320

A.3 Dividends paid and proposed

Woodside Petroleum Ltd, the parent entity, paid and proposed dividends set out below:

	2020 US$m	2019 US$m
(a) Dividends paid during the financial year		
Prior year fully franked final dividend US$0.55, paid on 20 March 2020 (2019: US$0.91, paid on 20 March 2019)	518	852
Current year fully franked interim dividend US$0.26, paid on 18 September 2020 (2019: US$0.36, paid on 20 September 2019)	248	337
	766	1,189
(b) Dividend declared subsequent to the reporting period (not recorded as a liability)		
Final dividend US$0.12 (2019: US$0.55)	115	518
(c) Other information		
Franking credits available for subsequent periods	1,823	1,565
Current year dividends per share (US cents)	38	91

The dividend reinvestment plan (DRP) was approved by the shareholders at the Annual General Meeting in 2003 for activation as required to fund future growth. The DRP was reactivated for the 2019 interim dividend and remains in place until further notice.

A.4 Earnings/(losses) per share

	2020	2019
Profit/(loss) attributable to equity holders of the parent (US$m)	(4,028)	343
Weighted average number of shares on issue	951,113,086	935,833,092
Basic and diluted earnings/(losses) per share (US cents)	(423.5)	36.7

Earnings/(losses) per share is calculated by dividing the profit/(loss) for the year attributable to ordinary equity holders of the parent by the weighted average number of ordinary shares on issue during the year. The weighted average number of shares makes allowance for shares reserved for employee share plans.

Total awards of 9,392,203 (2019: 10,501,088) are considered to be contingently issuable and therefore not dilutive.

There have been no significant transactions involving ordinary shares between the reporting date and the date of completion of these financial statements.

A.5 Taxes

	2020 US$m	2019 US$m
(a) Tax expense comprises		
PRRT		
Deferred tax benefit	(439)	(31)
PRRT benefit	(439)	(31)
Income tax		
Current year		
Current tax expense	275	325
Deferred tax (benefit)/expense	(1,308)	184
Adjustment to prior years		
Current tax expense	16	-
Deferred tax (benefit)/expense	(9)	2
Income tax (benefit)/expense	(1,026)	511
Tax (benefit)/expense	(1,465)	480
(b) Reconciliation of income tax expense		
Profit/(loss) before tax	(5,440)	862
PRRT benefit	439	31
Profit/(loss) before income tax	(5,001)	893
Income tax (benefit)/expense calculated at 30%	(1,500)	268
Foreign income tax benefit	(11)	-
Non-deductible items	2	-
Foreign expenditure not brought to account	473	242
Adjustment to prior years	7	2
Foreign exchange impact on tax expense/(benefit)	3	(1)
Income tax (benefit)/expense	(1,026)	511
(c) Reconciliation of PRRT benefit		
Profit/(loss) before tax	(5,440)	862
Non-PRRT assessable (profit)/loss	3,080	(528)
PRRT projects profit/(loss) before tax1	(2,360)	334
PRRT (benefit)/expense calculated at 40%	(944)	134
Augmentation	(138)	(168)
Derecognition of Pluto general expenditure[1]	627	-
Other	16	3
PRRT benefit	(439)	(31)
(d) Deferred tax income statement reconciliation		
PRRT		
Production and growth assets	(242)	190
Augmentation for current year	(138)	(168)
Provisions	(32)	(52)
Other	(27)	(1)
PRRT benefit	(439)	(31)
Income tax		
Oil and gas properties	(981)	94
Exploration and evaluation assets	(210)	92
Provisions	(106)	(97)
PRRT liabilities	134	6
Lease assets and liabilities	(16)	(23)
Unused tax losses and tax credits	(149)	73
Other	11	23
Income tax deferred tax (benefit)/expense	(1,317)	168
Deferred tax (benefit)/expense	(1,756)	137
(e) Deferred tax balance sheet reconciliation		
Deferred tax assets		
PRRT		
Production and growth assets	1,098	989
Augmentation for current year	124	145
Provisions	46	37
Other	36	2
	1,304	1,173

	2020 US$m	2019 US$m
(e) Deferred tax balance sheet reconciliation (cont.)		
Deferred tax liabilities		
PRRT		
Production and growth assets	224	525
Augmentation for current year	(14)	(23)
Provisions	(214)	(191)
Other	4	(3)
Income tax		
Oil and gas properties	846	1,827
Exploration and evaluation assets	255	465
Lease assets and liabilities	(39)	(23)
Provisions	(696)	(590)
PRRT liabilities	391	257
Unused tax losses and tax credits	(149)	-
Other[2]	(59)	(51)
	549	2,193
(f) Tax payable reconciliation		
Income tax payable	46	86
	46	86
(g) Effective income tax rate: Australian and global operations		
Effective income tax rate[3]		
Australia	29.6%	29.3%
Global	20.5%	57.2%
(h) Current income tax expense reconciliation		
Profit/(loss) before income tax	(5,001)	893
Income tax (benefit)/expense at the statutory tax rate of 30%	(1,500)	268
Foreign income tax benefit	(11)	-
Non-temporary differences[4,5]	475	242
Temporary differences: deferred tax[5]	1,308	(184)
Foreign exchange impact on tax expense/(benefit)	3	(1)
Current income tax expense	275	325

1. A net $348 million reduction of the Pluto PRRT deferred tax asset includes derecognition of general expenditure of $627 million (based on expected future utilisation) offset by a reduction in the Pluto asset accounting base of $279 million (included within 'PRRT projects profit/(loss) before tax').
2. $19 million tax benefit recognised in other comprehensive income (2019: Nil).
3. The global operations effective income tax rate (ETR) is calculated as the Group's income tax expense/(benefit) divided by profit/(loss) before income tax. The Australian operations ETR is calculated with reference to all Australian companies and excludes foreign exchange on settlement and revaluation of income tax liabilities. The global ETR is impacted by one-off items including the impairment of foreign assets and onerous contract provision.
4. Primarily expenditure in respect of foreign operations, including the impairment of foreign assets and onerous contract provision.
5. Excludes adjustment to prior years.

A.5 Taxes (cont.)

Tax transparency code

Woodside participates in the Australian Board of Taxation's voluntary Tax Transparency Code (TTC). To increase public confidence in the contributions and compliance of corporate taxpayers, the TTC recommends public disclosure of tax information. Woodside has addressed the recommended disclosures in two parts. The Part A disclosures are addressed within this Taxes note; the Part B disclosures are addressed in our Sustainable Development Report.

Recognition and measurement

Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset is realised. The tax rates and laws used to determine the amount are based on those that have been enacted or substantially enacted by the end of the reporting period. Income taxes relating to items recognised directly in equity are recognised in equity.

Current taxes

Current tax expense is the expected tax payable on the taxable income for the year and any adjustment to tax payable in respect of previous years.

Deferred taxes

Deferred tax expense represents movements in the temporary differences between the carrying amount of an asset or liability in the statement of financial position and its tax base.

With the exception of those noted below, deferred tax liabilities are recognised for all taxable temporary differences.

Deferred tax assets are recognised for deductible temporary differences, unused tax losses and tax credits only if it is probable that sufficient future taxable income will be available to utilise those temporary differences and losses.

Deferred tax is not recognised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of assets and liabilities in a transaction that affects neither accounting profit nor the taxable profit.

In relation to PRRT, the impact of future augmentation on expenditure is included in the determination of future taxable profits when assessing the extent to which a deferred tax asset can be recognised in the statement of financial position.

Offsetting deferred tax balances

Deferred tax assets and liabilities are offset only if there is a legally enforceable right to offset current tax assets and liabilities and when they relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities that the Group intends to settle its current tax assets and liabilities on a net basis. Refer to Notes E.8 and E.9 for detail on the tax consolidated group.

Key estimates and judgements

(a) Income tax classification

Judgement is required when determining whether a particular tax is an income tax or another type of tax. Accounting for deferred tax is applied to income taxes as described above, but is not applied to other types of taxes, e.g. North West Shelf royalties and excise. Such taxes are recognised in the income statement on an appropriate basis. PRRT is considered, for accounting purposes, to be an income tax.

(b) Deferred tax asset recognition

Australian tax losses: A deferred tax asset of $149 million (2019: nil) has been recognised for carry forward unused tax losses and credits. The Group has determined that it is probable that sufficient future taxable income will be available to utilise those losses and credits.

Foreign tax losses: Deferred tax assets of $477 million (2019: $471 million) relating to unused foreign tax losses have not been recognised on the basis that it is not probable that the assets will be utilised based on current planned activities in those regions.

PRRT: The recoverability of PRRT deferred tax assets is primarily assessed with regard to future oil price assumptions. As a result of the decrease in long-term oil prices (as disclosed in Note B.4), $348 million of the Pluto PRRT deferred tax asset (DTA) has been derecognised, being the portion for which it is no longer probable that future taxable profits will be in excess of the deductible expenditure including augmentation. The Pluto PRRT DTA of $1,053 million continues to be recognised on the basis that it is probable that future taxable profits will be available to utilise the deductible expenditure. A long-term bond rate of 1.0% (31 December 2019: 1.3%) was used for the purposes of augmentation. All other deferred PRRT and income tax movements are a result of the effective income tax rates applicable to each Australian or foreign jurisdiction.

Certain deferred tax assets on deductible temporary differences have not been recognised on the basis that deductions from future augmentation of the deductible temporary difference will be sufficient to offset future taxable profit. $4,167 million (2019: $3,831 million) relates to the North West Shelf Project, $1,345 million (2019: $654 million) relates to the quarantined exploration spend and impaired general spend of Pluto LNG and $1,049 million (2019: $856 million) relates to Wheatstone. A long-term bond rate of 1.0% (31 December 2019: 1.3%) was used for the purposes of augmentation.

Had an alternative approach been used to assess recovery of the deferred tax assets, whereby future augmentation was not included in the assessment, the additional deferred tax assets would be recognised, with a corresponding benefit to income tax expense. It was determined that the approach adopted provides the most meaningful information on the implications of the PRRT regime, whilst ensuring compliance with AASB 112 *Income Taxes*.

In this section

This section addresses the strategic growth (exploration and evaluation) and core producing (oil and gas properties) assets position of the Group at the end of the reporting period including, where applicable, the accounting policies and key estimates and judgements applied. This section also includes the impairment position of the Group at the end of the reporting period.

B.1 Segment production and growth assets

	Producing								Development		Other			
	North West Shelf		Pluto		Australia Oil		Wheatstone		Development		Other		Consolidated	
	2020 US$m	2019 US$m	2020 US$m	2019 US$m	2020 US$m	2019 US$m	2020 US$m	2019 US$m	2020 US$m	2019 US$m	2020 US$m	2019 US$m	2020 US$m	2019 US$m
Balance as at 31 December														
Oceania	9	19	-	429	13	21	3	2	1,727	1,624	-	148	1,752	2,243
Asia	-	-	-	-	-	-	-	-	-	-	229	199	229	199
Canada	-	-	-	-	-	-	-	-	-	742	-	-	-	742
Africa	-	-	-	-	-	-	-	-	51	607	13	16	64	623
Other	-	-	-	-	-	-	-	-	-	-	-	2	-	2
Total exploration and evaluation	9	19	-	429	13	21	3	2	1,778	2,973	242	365	2,045	3,809
Balance as at 31 December														
Land and buildings	9	15	307	388	-	-	432	664	-	-	1	1	749	1,068
Transferred exploration and evaluation	61	89	167	258	90	189	113	193	-	-	-	-	431	729
Plant and equipment	1,574	2,123	7,498	8,891	784	1,509	2,074	3,287	-	-	3	3	11,933	15,813
Marine vessels and carriers	11	36	-	-	-	-	-	-	-	-	-	-	11	36
Projects in development	131	113	549	321	10	7	395	210	1,055	-	3	1	2,143	652
Total oil and gas properties	1,786	2,376	8,521	9,858	884	1,705	3,014	4,354	1,055	-	7	5	15,267	18,298
Balance as at 31 December														
Land and buildings	12	-	22	20	-	-	3	-	38	34	317	342	392	396
Marine vessels and carriers	1	-	156	177	-	-	-	-	-	-	435	375	592	552
Total lease assets	13	-	178	197	-	-	3	-	38	34	752	717	984	948
Additions to exploration and evaluation:														
Exploration	-	4	-	3	-	-	1	2	26	-	18	49	45	58
Evaluation	-	3	-	9	-	-	-	14	294	383	16	7	310	416
Restoration	-	-	-	3	-	-	-	-	44	2	-	-	44	5
	-	7	-	15	-	-	1	16	364	385	34	56	399	479
Additions to oil and gas properties:														
Oil and gas properties	68	81	322	297	93	257	287	90	767	-	2	1	1,539	726
Capitalised borrowings costs[1]	1	-	17	5	2	34	10	2	27	-	-	-	57	41
Restoration	34	65	68	42	42	62	43	17	-	-	-	-	187	186
	103	146	407	344	137	353	340	109	794	-	2	1	1,783	953
Additions to lease assets:														
Land and buildings	12	-	6	-	-	-	3	-	1	-	2	1	24	1
Marine vessels and carriers	1	-	-	-	-	-	-	-	-	-	101	12	102	12
	13	-	6	-	-	-	3	-	1	-	103	13	126	13

1. Borrowing costs capitalised were at a weighted average interest rate of 3.8% (2019: 4.2%).

Refer to Note A.1 for descriptions of the Group's segments and geographical regions.

B.2 Exploration and evaluation

	Oceania US$m	Asia US$m	Canada US$m	Africa US$m	Other US$m	Total US$m
Year ended 31 December 2020						
Carrying amount at 1 January 2020	2,243	199	742	623	2	3,809
Additions	272	34	67	26	-	399
Amortisation of licence acquisition costs	(5)	(4)	-	(3)	-	(12)
Expensed[1]	-	-	-	-	(2)	(2)
Impairment losses[2]	(748)	-	(809)	-	-	(1,557)
Transferred exploration and evaluation	(10)	-	-	(582)	-	(592)
Carrying amount at 31 December 2020	1,752	229	-	64	-	2,045
Year ended 31 December 2019						
Carrying amount at 1 January 2019	2,002	192	1,408	563	15	4,180
Additions	325	11	54	60	29	479
Amortisation of licence acquisition costs	(11)	(4)	-	-	-	(15)
Expensed[1]	(4)	-	-	-	(42)	(46)
Impairment losses[2]	-	-	(720)	-	-	(720)
Transferred exploration and evaluation	(69)	-	-	-	-	(69)
Carrying amount at 31 December 2019	2,243	199	742	623	2	3,809
Exploration commitments						
Year ended 31 December 2020	11	55	-	46	3	115
Year ended 31 December 2019	13	32	-	44	15	104

1. $2 million of exploration and evaluation expensed relates to unsuccessful wells written off during the period (2019: $46 million).
2. Refer to Note B.4 for details on impairment.

Recognition and measurement

Expenditure on exploration and evaluation is accounted for in accordance with the area of interest method. The Group's application of the accounting policy is closely aligned to the US GAAP-based successful efforts method.

Areas of interest are based on a geographical area for which the rights of tenure are current. All exploration and evaluation expenditure, including general permit activity, geological and geophysical costs and new venture activity costs, is expensed as incurred except for the following:

- where the expenditure relates to an exploration discovery for which the assessment of the existence or otherwise of economically recoverable hydrocarbons is not yet complete; or
- where the expenditure is expected to be recouped through successful exploitation of the area of interest, or alternatively, by its sale.

The costs of acquiring interests in new exploration and evaluation licences are capitalised. The costs of drilling exploration wells are initially capitalised pending the results of the well.

Costs are expensed where the well does not result in the successful discovery of economically recoverable hydrocarbons and the recognition of an area of interest.

Subsequent to the recognition of an area of interest, all further evaluation costs relating to that area of interest are capitalised.

Upon approval for the commercial development of an area of interest, accumulated expenditure for the area of interest is transferred to oil and gas properties.

In the statement of cash flows, those cash flows associated with capitalised exploration and evaluation expenditure, including unsuccessful wells, are classified as cash flows used in investing activities.

Exploration commitments

The Group has exploration expenditure obligations which are contracted for, but not provided for in the financial statements. These obligations may be varied from time to time and are expected to be fulfilled in the normal course of the Group's operations.

Impairment

Refer to Note B.4 for details on impairment, including any write-offs.

Key estimates and judgements

Area of interest

Typically, an area of interest (AOI) is defined by the Group as an individual geographical area whereby the presence of hydrocarbons is considered favourable or proved to exist. The Group has established criteria to recognise and maintain an AOI.

B.3 Oil and gas properties

	Land and buildings US$m	Transferred exploration and evaluation US$m	Plant and equipment US$m	Marine vessels and carriers US$m	Projects in development US$m	Total US$m
Year ended 31 December 2020						
Carrying amount at 1 January 2020	1,068	729	15,813	36	652	18,298
Additions	-	-	150	-	1,633	1,783
Disposals at written down value	-	-	(3)	-	(2)	(5)
Depreciation and amortisation	(55)	(99)	(1,533)	(2)	-	(1,689)
Impairment losses[1]	(264)	(199)	(2,636)	(23)	(590)	(3,712)
Completions and transfers	-	-	142	-	450	592
Carrying amount at 31 December 2020	749	431	11,933	11	2,143	15,267
At 31 December 2020						
Historical cost	1,722	1,348	31,225	184	2,791	37,270
Accumulated depreciation and impairment	(973)	(917)	(19,292)	(173)	(648)	(22,003)
Net carrying amount	749	431	11,933	11	2,143	15,267
Year ended 31 December 2019						
Carrying amount at 1 January 2019	1,100	625	15,460	66	1,630	18,881
Additions	-	-	122	-	831	953
Disposals at written down value	-	-	(3)	(13)	(2)	(18)
Depreciation and amortisation	(57)	(101)	(1,412)	(4)	-	(1,574)
Impairment losses[1]	-	-	-	(17)	-	(17)
Completions and transfers	25	205	1,646	4	(1,807)	73
Carrying amount at 31 December 2019	1,068	729	15,813	36	652	18,298
At 31 December 2019						
Historical cost	1,722	1,348	30,928	184	710	34,892
Accumulated depreciation and impairment	(654)	(619)	(15,115)	(148)	(58)	(16,594)
Net carrying amount	1,068	729	15,813	36	652	18,298

1. Refer to Note B.4 for details on impairment.

Recognition and measurement

Oil and gas properties are stated at cost less accumulated depreciation and impairment charges. Oil and gas properties include the costs to acquire, construct, install or complete production and infrastructure facilities such as pipelines and platforms, capitalised borrowing costs, transferred exploration and evaluation assets, development wells and the estimated cost of dismantling and restoration.

Subsequent capital costs, including major maintenance, are included in the asset's carrying amount only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be reliably measured.

Depreciation and amortisation

Oil and gas properties and other plant and equipment are depreciated to their estimated residual values at rates based on their expected useful lives.

Transferred exploration and evaluation and offshore plant and equipment are depreciated using the unit of production basis over proved plus probable reserves or proved reserves for late life assets. Onshore plant and equipment is depreciated using a straight-line basis over the lesser of useful life and the life of proved plus probable reserves. On a straight-line basis the assets have an estimated useful life of 5-50 years.

All other items of oil and gas properties are depreciated using the straight-line method over their useful life. They are depreciated as follows:

- Buildings – 24-40 years;
- Marine vessels and carriers – 10-40 years;

Impairment

Refer to Note B.4 for details on impairment.

Capital commitments

The Group has capital expenditure commitments contracted for, but not provided for in the financial statements, of $1,569 million (2019: $865 million).

- Other plant and equipment – 5-15 years; and
- Land is not depreciated

Key estimates and judgements

(a) Reserves

The estimation of reserves requires significant management judgement and interpretation of complex geological and geophysical models in order to make an assessment of the size, shape, depth and quality of reservoirs, and their anticipated recoveries.

Estimates of oil and natural gas reserves are used to calculate depreciation and amortisation charges for the Group's oil and gas properties. Judgement is used in determining the reserve base applied to each asset. Typically, late life oil assets use proved reserves.

Estimates are reviewed at least annually or when there are changes in the economic circumstances impacting specific assets or asset groups. These changes may impact depreciation, asset carrying values, restoration provisions and deferred tax balances. If proved plus probable (2P) reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the asset's carrying value.

For more information regarding reserve assumptions, refer to the reserves and resources statement on pages 48-51 of the Annual Report.

(b) Depreciation and amortisation

Judgement is required to determine when assets are available for use to commence depreciation and amortisation. Depreciation and amortisation generally commences on first production.

B.4 Impairment of exploration and evaluation and oil and gas properties

Exploration and evaluation

Impairment testing

The recoverability of the carrying amount of exploration and evaluation assets is dependent on successful development and commercial exploitation, or alternatively, sale of the respective AOI.

Each AOI is reviewed half-yearly to determine whether economic quantities of hydrocarbons have been found or whether further exploration and evaluation work is underway or planned to support continued carry forward of capitalised costs. Where a potential impairment is indicated for an AOI, an assessment is performed using a fair value less costs to dispose (FVLCD) method to determine its recoverable amount. Upon approval for commercial development, exploration and evaluation assets are also assessed for impairment before they are transferred to oil and gas properties.

Impairment calculations

The recoverable amounts of exploration and evaluation assets are determined using FVLCD as there is no value in use (VIU). Costs to dispose are the incremental costs directly attributable to the disposal of an asset (disposal group), excluding finance costs and income tax expense.

If the carrying amount of an AOI exceeds its recoverable amount, the AOI is written down to its recoverable amount and an impairment loss is recognised in the income statement.

For assets previously impaired, if the recoverable amount exceeds the carrying amount, the impairment loss is reversed, but only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined if no impairment loss had been recognised.

Oil and gas properties

Impairment testing

The carrying amounts of oil and gas properties are assessed half-yearly to determine whether there is an indication of impairment or impairment reversal for those assets which have previously been impaired. Indicators of impairment and impairment reversals include changes in future selling prices, future costs and reserves.

Oil and gas properties are assessed for impairment indicators and impairments on a cash-generating unit (CGU) basis. CGUs are determined as an FPSO and associated oil fields for an oil asset, and an LNG plant, offshore infrastructure and associated gas fields for a gas asset.

If there is an indicator of impairment or impairment reversal for a CGU then the recoverable amount is calculated.

Impairment calculations

The recoverable amount of an asset or CGU is determined as the higher of its VIU and FVLCD. VIU is determined by estimating future cash flows after taking into account the risks specific to the asset and discounting to present value using an appropriate discount rate.

If the carrying amount of an asset or CGU exceeds its recoverable amount, the asset or CGU is written down and an impairment loss is recognised in the income statement.

For assets previously impaired, if the recoverable amount exceeds the carrying amount, the impairment loss is reversed. The carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortisation, if no impairment loss had been recognised.

B.4 Impairment of exploration and evaluation and oil and gas properties (cont.)

Recognised impairment

As at 30 June 2020 the Group assessed each AOI and CGU and identified the following indicators of impairment for certain AOIs and all CGUs:

- AOIs – uncertainties on fiscal conditions and/or development strategies have led to a lack of substantive ongoing and/or planned activity; and
- CGUs – the decrease in global oil and gas prices due to the impacts of the COVID-19 pandemic, oversupply and weakened global demand.

Impairment losses before tax are recognised in other expenses, refer to Note A.1.

The results are set out in the following table, which includes the AOIs and CGUs which were subject to impairment testing:

			Impairment losses							
				Oil and gas properties						
Segment	AOI/CGU	Recoverable amount[1] US$m	Exploration and evaluation US$m	Land and buildings US$m	Transferred exploration and evaluation US$m	Plant and equipment US$m	Marine vessels and carriers US$m	Projects in development US$m	Total US$m
Producing	Pluto (WA-404-P)[2,4]	-	429	-	-	-	-	-	-
Development	Kitimat LNG[5]	-	809	-	-	-	-	-	-
	Sunrise[6]	-	168	-	-	-	-	-	-
Other segments	Toro (WA-93-R)/ Ragnar (WA-94-R)[3,7]	-	151	-	-	-	-	-	-
Producing	North West Shelf	1,922	-	2	15	387	23	27	454
	Pluto	9,712	-	54	59	666	-	83	862
	Australia Oil								
	Vincent (Ngujima-Yin)	836	-	-	64	517	-	26	607
	NWS Oil(Okha)	102	-	-	3	61	-	3	67
	Wheatstone	3,029	-	208	58	1,005	-	130	1,401
Development	Sangomar	415	-	-	-	-	-	321	321
	Total	16,016	1,557	264	199	2,636	23	590	3,712

1. The recoverable amounts for exploration and evaluation assets and oil and gas properties have been determined using the FVLCD and VIU methods, respectively. The carrying amount of the CGUs includes all assets allocated to the CGU. Refer to key estimates and judgements for further details.
2. The impairment of Pluto (WA-404-P) has resulted in a reclassification of the Greater Pluto (WA-404-P) Proved (1P) Undeveloped Reserves of 91 MMboe and Proved plus Probable (2P) Undeveloped Reserves of 123 MMboe, to Best Estimate (2C) Contingent Resources.
3. Converted from WA-430-P.

Impairment indicators for exploration and evaluation assets:

4. Increased uncertainty of development timing, given the prioritisation of the higher-value Scarborough resource.
5. The revision of long-term oil and Alberta natural gas market spot price assumptions, and a change to the development concept to a standalone LNG facility, de-linked from the upstream resource, with different accounting requirements.
6. Increased uncertainty of regulatory conditions, fiscal terms and development concept.
7. Increased uncertainty of development timing.

Sensitivity analysis

It is estimated that changes in the following key assumptions would result in a higher or lower impairment than what was determined as at 30 June 2020:

			Sensitivity[1]					
			Discount rate: increase of 1%[2]	Discount rate: decrease of 1%[2]	Oil price: increase of 10%	Oil price: decrease of 10%	FX: increase of 12%	FX: decrease of 12%
Oil and gas properties	Producing	North West Shelf	(72)	78	269	(269)	(89)	89
		Pluto	(487)	528	1,210	(1,244)	(219)	219
		Australia Oil						
		Vincent (Ngujima-Yin)	(24)	26	105	(105)	(33)	33
		NWS Oil(Okha)	(5)	5	40	(40)	(25)	25
		Wheatstone	(266)	305	514	(514)	(118)	118
	Development	Sangomar	(61)	67	122	(130)	N/A	N/A

1. The sensitivities represent reasonable possible changes to the discount rate, oil price and FX assumptions.
2. A change of 1% represents 100 basis points.

B.4 Impairment of exploration and evaluation and oil and gas properties (cont.)

Following the impairment recognised at 30 June 2020, the Group assessed each AOI and CGU for indicators of impairment as at 31 December 2020 in accordance with the Group's accounting policy. In assessing whether there was an indicator of impairment or impairment reversal, the Group considered whether there have been any significant changes in the key estimates and judgements and underlying project assumptions used for the 30 June 2020 impairment assessment and determined that there had been none. No indicators of additional impairment or impairment reversal were identified.

For the year ended 31 December 2019 the following impairments were recognised:

Exploration and evaluation

On 10 December 2019, the operator of the Kitimat LNG project announced its decision to exit the project and subsequently announced an impairment of its interest in the asset. This was considered to be an indicator of impairment and the recoverable amount of the Kitimat AOI was calculated as $742 million as at 31 December 2019. An impairment loss of $720 million was recognised in other expenses in the Development segment of Note A.1. The FVLCD for the Kitimat LNG AOI was determined as the present value of the estimated future cash flows (expressed in real terms) expected to arise from the development and use of the asset using assumptions that an independent market participant would take into account. These cash flows were discounted using a post-tax discount rate that reflected current market assessments of the time value of money and the risks specific to the Kitimat LNG AOI. The FVLCD was classified as Level 3 on the fair value hierarchy.

Oil and gas properties

The sale of two LNG vessels in the North West Shelf operating segment resulted in an impairment loss of $17 million as the assets' carrying value exceeded their FVLCD, which was determined based on the underlying sale agreements, classified as Level 3 on the fair value hierarchy. An impairment loss of $17 million was recognised in other expenses in the North West Shelf operating segment of Note A.1.

Key estimates and judgements

Recoverable amount calculation key assumptions

In determining the recoverable amounts of exploration and evaluation assets, the market comparison approach using adjusted market multiples (fair value hierarchy Level 3) has been utilised to determine FVLCD.

In determining the recoverable amount of CGUs, estimates are made regarding the present value of future cash flows when determining the VIU. These estimates require significant management judgement and are subject to risk and uncertainty, and hence changes in economic conditions can also affect the assumptions used and the rates used to discount future cash flow estimates.

The basis for the estimates used to determine recoverable amounts as at 30 June 2020 is set out below:

- Resource estimates – 2P reserves for oil and gas properties as disclosed in the reserves and resources statement in the 31 December 2019 Annual Report on pages 44 to 47.
- Inflation rate – an inflation rate of 2.0% has been applied (31 December 2019: 2.0%).
- Foreign exchange rates – a rate of $0.75 US$:AU$ (31 December 2019: $0.75) is based on management's view of long-term exchange rates.
- Discount rates – a range of pre-tax discount rates between 9.3% and 14.8% (post-tax discount rates 7.5% and 11.0%) for CGUs has been applied. The discount rate reflects an assessment of the risks specific to the asset, including country risk.
- An evaluation of climate risk impacts, including a long-term Australian carbon price of US$80/tonne (real terms 2020), applicable to Australian emissions that exceed facility-specific baselines in accordance with Australian regulations.
- LNG price – the majority of LNG sales contracts are linked to an oil price marker; accordingly the LNG prices used are consistent with oil price assumptions.
- Oil prices – derived from long-term views of global supply and demand, building upon past experience of the industry and consistent with external sources. Prices are adjusted for premiums and discounts based on the nature and quality of the product. The nominal Brent oil prices (US$/bbl) used were:

	2020	2021	2022	2023	2024	2025
30 June 2020	35	45	57	62	67	72[1]
31 December 2019	63	63	68	72	76	80[1]

1. Based on US$65/bbl (2020 real terms) from 2025 and prices are escalated at 2.0% onwards (31 December 2019: US$72.5/bbl (2020 real terms) and prices are escalated at 2.0% onwards).

B.5 Significant production and growth asset acquisitions

On 22 December 2020, Woodside completed the acquisition of Capricorn Senegal Limited's (Cairn's) interest in the RSSD Joint Venture (36.44% interest in the Sangomar exploitation area and 40% interest in the remaining RSSD evaluation area) for an aggregate purchase price of $527 million. The transaction was accounted for as an asset acquisition.

Additional payments of up to $100 million are contingent on future commodity prices and the timing of first oil. The contingent payments are accounted for as contingent liabilities in accordance with the Group's accounting policies.

As at 31 December 2020, Woodside holds a 68.33% interest in the Sangomar exploitation area and a 75% interest in the remaining RSSD evaluation area.

Assets acquired and liabilities assumed

The identifiable assets and liabilities acquired as at the date of the acquisition inclusive of transaction costs were:

	US$m
Oil and gas properties	540
Exploration and evaluation	26
Cash acquired	5
Payables	(51)
Net other assets and liabilities assumed	7
Total identifiable net assets at acquisition	527

Cash flows on acquisition

	US$m
Purchase cash consideration	525
Transaction costs	2
Total purchase consideration	527
Net cash outflows on acquisition	527

In December 2020, the Group exercised its right to pre-empt the sale by FAR Senegal RSSD SA (FAR) to ONGC Videsh Vankorneft Pte Ltd (ONGC) of FAR's interest in the RSSD Joint Venture (13.67% interest in the Sangomar exploitation area and 15% interest in the remaining RSSD evaluation area). The transaction is subject to FAR shareholder approval and certain other conditions, and as at 31 December 2020 has not completed. The terms of the transaction will reflect those of the FAR/ONGC transaction including payment to FAR of $45 million, reimbursement of FAR's share of working capital from 1 January 2020 to completion of the transaction and certain contingent payments capped at $55 million. Woodside's interest will increase to 82% for the Sangomar exploitation area and 90% for the remaining RSSD evaluation area following the completion of the transaction.

In this section

This section addresses cash, debt and the capital position of the Group at the end of the reporting period including, where applicable, the accounting policies applied and the key estimates and judgements made.

Key financial and capital risks in this section

Capital risk management

Capital management is undertaken to ensure that a secure, cost-effective and flexible supply of funds is available to meet the Group's operating and capital expenditure requirements. A stable capital base is maintained from which the Group can pursue its growth aspirations, whilst maintaining a flexible capital structure that allows access to a range of debt and equity markets to both draw upon and repay capital.

The Dividend Reinvestment Plan (DRP) was approved by shareholders at the Annual General Meeting in 2003 for activation as required to fund future growth. The DRP was reactivated for the 2019 interim dividend and will remain in place until further notice.

A range of financial metrics are monitored, including gearing and cash flow leverage, and Treasury policy breaches and exceptions.

Liquidity risk management

Liquidity risk arises from the financial liabilities of the Group and the Group's subsequent ability to meet its obligations to repay financial liabilities as and when they fall due. The liquidity position of the Group is managed to ensure sufficient liquid funds are available to meet its financial commitments in a timely and cost-effective manner.

The Group's liquidity is continually reviewed, including cash flow forecasts to determine the forecast liquidity position and maintain appropriate liquidity levels. At 31 December 2020, the Group had a total of $6,704 million (2019: $6,952 million) of available undrawn facilities and cash at its disposal. The maturity profile of interest-bearing liabilities is disclosed in Note C.2, trade and other payables are disclosed in Note D.4 and lease liabilities are disclosed in Note D.7. Financing facilities available to the Group are disclosed in Note C.2.

Interest rate risk management

Interest rate risk is the risk that the Group's financial position will fluctuate due to changes in market interest rates.

The Group's exposure to the risk of changes in market interest rates relates primarily to financial instruments with floating interest rates including long-term debt obligations, cash and short-term deposits. The Group manages its interest rate risk by maintaining an appropriate mix of fixed and floating rate debt. To manage the ratio of fixed rate debt to floating rate debt, the Group may enter into interest rate swaps. The Group holds cross-currency interest rate swaps to hedge the foreign exchange risk (refer to Section A) and interest rate risk of the CHF denominated medium term note. The Group also holds interest rate swaps to hedge the interest rate risk associated with the $600 million syndicated facility. Refer to Notes C.2 and D.6 for further details.

At the reporting date, the Group was exposed to various benchmark interest rates that were not designated in cash flow hedges, $3,527 million (2019: $3,981 million) on cash and cash equivalents, $450 million (2019: $533 million) on interest-bearing liabilities (excluding transaction costs) and $15 million (2019: $7 million) on cross-currency interest rate swaps.

A reasonably possible change in the USD London Interbank Offered Rate (LIBOR) (+0.5%/-0.5% (2019: +1.0%/-1.0%)), with all variables held constant, would not have a material impact on the Group's equity or the income statement in the current period.

The Group's Treasury function is closely monitoring the market and the output from the various industry working groups managing the transition to new benchmark interest rates. The Treasury function is assessing the implications of the Interbank Offered Rates (IBOR) reform across the Group and will manage and execute the transition from current benchmark rates to alternative benchmark rates.

C.1 Cash and cash equivalents

	2020 US$m	2019 US$m
Cash and cash equivalents		
Cash at bank	367	175
Term deposits	3,237	3,883
Total cash and cash equivalents	3,604	4,058

Recognition and measurement

Cash and cash equivalents in the statement of financial position comprise cash at bank and short-term deposits with an original maturity of three months or less. Cash and cash equivalents are stated at face value in the statement of financial position.

Foreign exchange risk

The Group held $78 million of cash and cash equivalents at 31 December 2020 (2019: $47 million) in currencies other than US dollars.

C.2 Interest-bearing liabilities and financing facilities

	Bilateral Facilities US$m	Syndicated Facilities US$m	JBIC Facility US$m	US Bonds US$m	Medium Term Notes US$m	Total US$m
Year ended 31 December 2020						
At 1 January 2020	(3)	(4)	333	4,775	578	5,679
Repayments	-	-	(83)	-	-	(83)
Drawdowns	-	600	-	-	-	600
Fair value adjustment and foreign exchange movement	-	-	-	-	19	19
Transaction costs capitalised and amortised	(1)	(3)	-	3	-	(1)
Carrying amount at 31 December 2020	(4)	593	250	4,778	597	6,214
Current	(1)	(2)	83	696	-	776
Non-current	(3)	595	167	4,082	597	5,438
Carrying amount at 31 December 2020	(4)	593	250	4,778	597	6,214
Undrawn balance at 31 December 2020	1,900	1,200	-	-	-	3,100
Year ended 31 December 2019						
At 1 January 2019	(2)	(1)	417	3,284	373	4,071
Repayments	-	-	(84)	-	-	(84)
Drawdowns	-	-	-	1,500	200	1,700
Fair value adjustment and foreign exchange movement	-	-	-	-	4	4
Transaction costs capitalised and amortised	(1)	(3)	-	(9)	1	(12)
Carrying amount at 31 December 2019	(3)	(4)	333	4,775	578	5,679
Current	(1)	(1)	83	(4)	-	77
Non-current	(2)	(3)	250	4,779	578	5,602
Carrying amount at 31 December 2019	(3)	(4)	333	4,775	578	5,679
Undrawn balance at 31 December 2019	1,694	1,200	-	-	-	2,894

Recognition and measurement

All borrowings are initially recognised at fair value less transaction costs. Borrowings are subsequently carried at amortised cost. Any difference between the proceeds received and the redemption amount is recognised in the income statement over the period of the borrowings using the effective interest method.

Borrowings designated as a hedged item are measured at amortised cost adjusted to record changes in the fair value of risks that are being hedged in fair value hedges. The changes in the fair value risks of the hedged item resulted in a loss of $19 million being recorded (2019: loss of $4 million), and a gain of $18 million recorded on the hedging instrument (2019: gain of $5 million).

All bonds, notes and facilities are subject to various covenants and a negative pledge restricting future secured borrowings, subject to a number of permitted lien exceptions. Neither the covenants nor the negative pledges have been breached at any time during the reporting period.

Fair value

The carrying amount of interest-bearing liabilities approximates their fair value, with the exception of the Group's unsecured bonds and the medium term notes. The unsecured bonds have a carrying amount of $4,778 million (2019: $4,775 million) and a fair value of $5,196 million (2019: $5,060 million). The medium term notes have a carrying amount of $597 million (2019: $578 million) and a fair value of $617 million (2019: $594 million). The fair value of the bonds and notes was determined using quoted prices in an active market, classified as Level 1 on the fair value hierarchy. The Group's repayment obligations remain unchanged.

Foreign exchange risk

All interest-bearing liabilities are denominated in US dollars, excluding the CHF175 million medium term note.

C.2 Interest-bearing liabilities and financing facilities (cont.)

Maturity profile of interest-bearing liabilities

The table below presents the contractual undiscounted cash flows associated with the Group's interest-bearing liabilities, representing principal and interest. The figures will not necessarily reconcile with the amounts disclosed in the consolidated statement of financial position.

	2020 US$m	2019 US$m
Due for payment in:		
1 year or less	979	297
1-2 years	470	980
2-3 years	462	462
3-4 years	178	439
4-5 years	1,161	171
More than 5 years	4,266	4,800
	7,516	7,149

Amounts exclude transaction costs.

Bilateral facilities

The Group has 14 bilateral loan facilities totalling $1,900 million (2019: 13 bilateral loan facilities totalling $1,694 million). Details of bilateral loan facilities at the reporting date are as follows:

Number of facilities	Term (years)	Currency	Extension option
6	5	US$	Evergreen
2	4	US$	Evergreen
6	3	US$	Evergreen

Interest rates are based on USD LIBOR and margins are fixed at the commencement of the drawdown period. Interest is paid at the end of the drawdown period. Evergreen facilities may be extended continually by a year subject to the bank's agreement.

Syndicated facility

On 3 July 2015, the Group executed an unsecured $1,000 million syndicated loan facility, which was increased to $1,200 million on 22 March 2016 and amended to $800 million on 15 November 2017. On 14 October 2019, Woodside increased the existing facility to $1,200 million, with $400 million expiring on 11 October 2022 and $800 million expiring on 11 October 2024. Interest rates are based on USD LIBOR and margins are fixed at the commencement of the drawdown period.

On 17 January 2020, the Group completed a new $600 million syndicated facility with a term of seven years. Interest is based on the USD London Interbank Offered Rate (LIBOR) plus 1.2%. Interest is paid on a quarterly basis.

Japan Bank for International Cooperation (JBIC) facility

On 24 June 2008, the Group entered into a two tranche committed loan facility of $1,000 million and $500 million respectively. The $500 million tranche was repaid in 2013. There is a prepayment option for the remaining balance. Interest rates are based on LIBOR. Interest is payable semi-annually in arrears and the principal amortises on a straight-line basis, with equal instalments of principal due on each interest payment date (every six months).

Under this facility, 90% of the receivables from designated Pluto LNG sale and purchase agreements are secured in favour of the lenders through a trust structure, with a required reserve amount of $30 million.

To the extent that this reserve amount remains fully funded and no default notice or acceleration notice has been given, the revenue from Pluto LNG continues to flow directly to the Group from the trust account.

Medium term notes

On 28 August 2015, the Group established a $3,000 million Global Medium Term Notes Programme listed on the Singapore Stock Exchange. Three notes have been issued under this programme as set out below:

Maturity date	Currency	Carrying amount (million)	Nominal interest rate
15 July 2022	US$	200	Floating three month US$ LIBOR
11 December 2023	CHF	175	1%
29 January 2027	US$	200	3%

The unutilised program is not considered to be an unused facility.

US bonds

The Group has five unsecured bonds issued in the United States of America as defined in Rule 144A of the US Securities Act of 1933 as set out below:

Maturity date	Carrying amount US$m	Nominal interest rate
10 May 2021	700	4.60%
5 March 2025	1,000	3.65%
15 September 2026	800	3.70%
15 March 2028	800	3.70%
4 March 2029	1,500	4.50%

Interest on the bonds is payable semi-annually in arrears.

During the period, the 2021 US bond for $700 million was reclassified from non-current to current interest-bearing liabilities due to its maturity date. The bond was redeemed on 10 February 2021.

C.3 Contributed equity

Recognition and measurement

Issued capital

Ordinary shares are classified as equity and recorded at the value of consideration received. The cost of issuing shares is shown in share capital as a deduction, net of tax, from the proceeds.

Reserved shares

The Group's own equity instruments, which are reacquired for later use in employee share-based payment arrangements (reserved shares), are deducted from equity. No gain or loss is recognised in the income statement on the purchase, sale, issue or cancellation of the Group's own equity instruments.

(a) Issued and fully paid shares

	Number of shares	US$m
Year ended 31 December 2020		
Opening balance	942,286,900	9,010
DRP - ordinary shares issued at A$25.61 (2019 final dividend)	12,072,034	181
DRP - ordinary shares issued at A$18.79 (2020 interim dividend)	6,091,035	83
Employee share plan - ordinary shares issued at A$18.27 (2017 Woodside equity plan)	1,775,845	23
Amounts as at 31 December 2020	962,225,814	9,297
Year ended 31 December 2019		
Opening balance	936,151,549	8,880
DRP - ordinary shares issued at A$31.34 (2019 interim dividend)	6,135,351	130
Amounts as at 31 December 2019	942,286,900	9,010

All shares are a single class with equal rights to dividends, capital, distributions and voting. The Company does not have authorised capital nor par value in relation to its issued shares.

(b) Shares reserved for employee share plans

	Number of shares	US$m
Year ended 31 December 2020		
Opening balance	1,985,306	(39)
Purchases during the year	2,242,345	(32)
Vested during the year	(2,461,552)	48
Amounts at 31 December 2020	1,766,099	(23)
Year ended 31 December 2019		
Opening balance	1,130,104	(31)
Purchases during the year	3,052,348	(66)
Vested during the year	(2,197,146)	58
Amounts at 31 December 2019	1,985,306	(39)

C.4 Other reserves

	2020 US$m	2019 US$m
Other reserves		
Employee benefits reserve	219	211
Foreign currency translation reserve	793	793
Hedging reserve	(71)	(12)
Distributable profits reserve	462	-
	1,403	992

Nature and purpose

Employee benefits reserve

Used to record share-based payments associated with the employee share plans and remeasurement adjustments relating to the defined benefit plan.

Foreign currency translation reserve

Used to record foreign exchange differences arising from the translation of the financial statements of foreign entities from their functional currency to the Group's presentation currency.

Hedging reserve

Used to record gains and losses on hedges designated as cash flow hedges, and foreign currency basis spread arising from the designation of a financial instrument as a hedging instrument. Gains and losses accumulated in the cash flow hedge reserve are taken to the income statement in the same period during which the hedged expected cash flows affect the income statement.

Distributable profits reserve

Used to record distributable profits generated by the Parent entity, Woodside Petroleum Ltd. As approved by resolution of the Directors on 29 June 2020, current and prior period profits of $710 million were transferred to the reserve that was established during the period.

In this section

This section addresses the other assets and liabilities position at the end of the reporting period including, where applicable, the accounting policies applied and the key estimates and judgements made.

Key financial and capital risks in this section

Credit risk management

Credit risk is the risk that a counterparty will not meet its obligation under a financial instrument or customer contract, leading to a financial loss to the Group. Credit risk arises from the financial assets of the Group, which comprise trade and other receivables, loans receivables and deposits with banks and financial institutions.

The Group manages its credit risk on trade receivables and financial instruments by predominantly dealing with counterparties with an investment grade credit rating. Sufficient collateral is obtained to mitigate the risk of financial loss when transacting with counterparties with below investment grade credit ratings. Customers who wish to trade on unsecured credit terms are subject to credit verification procedures. Receivable balances are monitored on an ongoing basis. As a result, the Group's exposure to bad debts is not significant. The Group's maximum credit risk is limited to the carrying amount of its financial assets.

Customer credit risk is managed by the Treasury function subject to the Group's established policy, procedures and controls relating to customer credit risk management. Credit quality of a customer is assessed based on an extensive credit rating scorecard and individual credit limits are defined in accordance with this assessment. Outstanding customer receivables are regularly monitored. At 31 December 2020, the Group had four customers (2019: seven customers) that owed the Group more than $10 million each and accounted for approximately 82% (2019: 85%) of all trade receivables. Payment terms are typically 14 to 30 days providing only a short credit exposure.

At 31 December 2020, the Group had a provision for credit losses of nil (2019: $1 million). Subsequent to 31 December 2020, 100% (2019: 100%) of the trade receivables balance of $164 million (2019: $208 million) has been received.

Credit risk from balances with banks is managed by the Treasury function in accordance with the Group's policy. The Group's main funds are placed as short-term deposits with reputable financial institutions with strong investment grade credit ratings.

D.1 Segment assets and liabilities

	2020 US$m	2019 US$m
(a) Segment assets		
NWS	1,943	2,541
Pluto	9,250	10,917
Australia Oil	978	1,803
Wheatstone	3,108	4,423
Development	3,055	3,028
Other segments	697	752
Unallocated items	5,592	5,889
	24,623	29,353

	2020 US$m	2019 US$m
(b) Segment liabilities		
NWS	679	643
Pluto	950	823
Australia Oil	848	755
Wheatstone	281	212
Development	265	189
Other segments	953	510
Unallocated items	7,772	8,812
	11,748	11,944

Refer to Note A.1 for descriptions of the Group's segments. Unallocated assets mainly comprise cash and cash equivalents, deferred tax assets and lease assets. Unallocated liabilities mainly comprise interest-bearing liabilities, deferred tax liabilities and lease liabilities.

D.2 Receivables

	2020 US$m	2019 US$m
(a) Receivables (current)		
Trade receivables[1]	164	208
Other receivables[1]	75	72
Loans receivable	59	52
Lease receivables	3	-
Interest receivable	1	10
Dividend receivable	1	1
	303	343
(b) Receivables (non-current)		
Loans receivable	394	222
Lease receivables	10	5
Defined benefit plan asset	19	18
	423	245

1. Interest-free and settlement terms are usually between 14 and 30 days.

Recognition and measurement

Trade receivables are initially recognised at the transaction price determined under AASB 15 *Revenue from Contracts with Customers*. Other receivables are initially recognised at fair value. Receivables that satisfy the contractual cash flow and business model tests are subsequently measured at amortised cost less an allowance for uncollectable amounts. Uncollectable amounts are determined using the expected loss impairment model. Collectability and impairment are assessed on a regular basis. Subsequent recoveries of amounts previously written off are credited against other expenses in the income statement. Certain receivables that do not satisfy the contractual cash flow and business model tests are subsequently measured at fair value (refer to Note D.6).

The Group's customers are required to pay in accordance with agreed payment terms. Depending on the product, settlement terms are 14 to 30 days from the date of invoice or bill of lading and customers regularly pay on time. There are no significant overdue trade receivables as at the end of the reporting period (2019: nil).

Fair value

The carrying amount of trade and other receivables approximates their fair value.

Foreign exchange risk

The Group held $68 million of receivables at 31 December 2020 (2019: $73 million) in currencies other than US dollars (predominantly Australian dollars).

Loans receivable

On 9 January 2020, Woodside Energy Finance (UK) Ltd entered into a secured loan agreement with Petrosen (the Senegal National Oil Company), to provide up to $450 million for the purpose of funding Sangomar project costs. The facility has a maximum term of 12 years and semi-annual repayments of the loan are due to commence at the earlier of 12 months after RFSU or 30 June 2025. The carrying amount of the loan receivable is $113 million at 31 December 2020 (2019: nil), which approximates its fair value. The remaining balance of loans receivable is due from non-controlling interests.

D.3 Inventories

	2020 US$m	2019 US$m
(a) Inventories (current)		
Petroleum products		
Goods in transit	18	39
Finished stocks	33	47
Warehouse stores and materials	74	90
	125	176
(b) Inventories (non-current)		
Warehouse stores and materials	40	-
	40	-

Recognition and measurement

Inventories include hydrocarbon stocks, consumable supplies and maintenance spares. Inventories are valued at the lower of cost and net realisable value. Cost is determined on a weighted average basis and includes direct costs and an appropriate portion of fixed and variable production overheads where applicable. Inventories determined to be obsolete or damaged are written down to net realisable value, being the estimated selling price less selling costs.

D.4 Payables

The following table shows the Group's payables balances and maturity analysis.

	< 30 days US$m	30-60 days US$m	> 60 days US$m	Total US$m
Year ended 31 December 2020				
Trade payables[1]	100	-	-	100
Other payables[1]	342	-	-	342
Interest payable[2]	7	5	51	63
Total payables	449	5	51	505
Year ended 31 December 2019				
Trade payables[1]	136	-	88	224
Other payables[1]	294	---	---	294
Interest payable[2]	4	-	59	63
Total payables	434	-	147	581

1. Interest-free and normally settled on 30 day terms.
2. Details regarding interest-bearing liabilities are contained in Note C.2.

Recognition and measurement

Trade and other payables are carried at amortised cost and are recognised when goods and services are received, whether or not billed to the Group, prior to the end of the reporting period.

Fair value

The carrying amount of payables approximates their fair value.

Foreign exchange risk

The Group held $210 million of payables at 31 December 2020 (2019: $369 million) in currencies other than US dollars (predominantly Australian dollars).

D.5 Provisions

	Restoration of operating locations[1] US$m	Employee benefits US$m	Onerous contracts[2] US$m	Other US$m	Total US$m
Year ended 31 December 2020					
At 1 January 2020	1,869	189	-	70	2,128
Change in provision	237	106	347	59	749
Unwinding of present value discount	28	-	2	-	30
Carrying amount at 31 December 2020	2,134	295	349	129	2,907
Current	54	272	46	128	500
Non-current	2,080	23	303	1	2,407
Net carrying amount	2,134	295	349	129	2,907
Year ended 31 December 2019					
At 1 January 2019	1,572	171	-	55	1,798
Change in provision	259	18	-	15	292
Unwinding of present value discount	38	-	-	-	38
Carrying amount at 31 December 2019	1,869	189	-	70	2,128
Current	35	167	-	70	272
Non-current	1,834	22	-	-	1,856
Net carrying amount	1,869	189	-	70	2,128

1. 2020 change in provision is due to a revision of discount rates of $173 million, new provisions and changes in estimates of $86 million offset by provisions used of $22 million.
2. 2020 change in provision is due to new provisions of $447 million offset by changes in estimates of $54 million, provisions used of $41 million and a revision of discount rates of $5 million.

Recognition and measurement

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

Restoration of operating locations

Provision is made for the obligation to restore operating locations. The provision is first recognised in the period in which the obligation arises. The nature of restoration activities includes the removal of facilities, abandonment of wells and restoration of affected areas.

Restoration provisions are updated annually, with the corresponding movement recognised against the related exploration and evaluation assets or oil and gas properties.

Over time, the liability is increased for the change in the present value based on a pre-tax discount rate appropriate to the risks inherent in the liability. The unwinding of the discount is recorded as an accretion charge within finance costs. The carrying amount capitalised in oil and gas properties is depreciated over the useful life of the related asset (refer to Note B.3).

Costs incurred that relate to an existing condition caused by past operations, and which do not have a future economic benefit, are expensed.

Employee benefits

Provision is made for employee benefits accumulated as a result of employees rendering services up to the end of the reporting period. These benefits include wages, salaries, annual leave and long service leave.

Liabilities in respect of employees' services rendered that are not expected to be wholly settled within one year after the end of the period in which the employees render the related services are recognised as long-term employee benefits.

These liabilities are measured at the present value of the estimated future cash outflow to the employees using the projected unit credit method. Liabilities expected to be wholly settled within one year after the end of the period in which the employees render the related services are classified as short-term benefits and are measured at the amount due to be paid.

Onerous contract provision

Provision is made for loss-making contracts at the present value of the lower of the net cost of fulfilling and the cost arising from failure to fulfill each contract.

More closely connected global gas markets and the Group's view of likely reduced margins available between North American and other gas markets, has given rise to a loss-making contract.

D.5 Provisions (cont.)

Key estimates and judgements

(a) Restoration obligations

The Group estimates the future removal costs of offshore oil and gas platforms, production facilities, wells and pipelines at different stages of the development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgemental assumptions regarding removal date, environmental legislation and regulations, the extent of restoration activities required, the engineering methodology for estimating cost, future removal technologies in determining the removal cost, and liability-specific discount rates to determine the present value of these cash flows. A range of pre-tax discount rates between 0.1% and 2% has been applied. If the discount rates were decreased by 0.5% then the provision would be $146 million higher. The proportion of the non-current balance not expected to be settled within 10 years is 73% (2019: 76%).

(b) Long service leave

Long service leave is measured at the present value of benefits accumulated up to the end of the reporting period. The liability is discounted using an appropriate discount rate. Management uses judgement to determine key assumptions used in the calculation including future increases in salaries and wages, future on-cost rates and future settlement dates of employees' departures.

(c) Legal case outcomes

Provisions for legal cases are measured at the present value of the amount expected to settle the claim. Management is required to use judgement when assessing the likely outcome of legal cases, estimating the risked amount and whether a provision or contingent liability should be recognised.

(d) Onerous contracts

The onerous contract provision assessment requires management to make certain estimates regarding the unavoidable costs and the expected economic benefits from the contract. These estimates require significant management judgement and are subject to risk and uncertainty, and hence changes in economic conditions can affect the assumptions. The present value of the provision was estimated using the assumptions set out below:

- Contract term – 20 years; the provision is released as contract deliveries are made from 2020 to 2040.
- Discount rate – a pre-tax, risk free US government bond rate of 1.390% has been applied.
- LNG pricing – forecast sales and purchase prices are subject to a number of price markers. Price assumptions are derived from long-term views of global supply and demand, building upon past experience of the industry and consistent with external sources. The nominal Brent oil prices and Henry Hub gas prices used at 31 December 2020 were:

	2021	2022	2023	2024	2025
Brent (US$/bbl)	50	57	62	67	72
Henry Hub (US$/MMBtu)	3.1	3.1	2.6	2.7	3.3

The effects of changes to discount rate and long-term oil prices on the carrying value of the provision are estimated as follows:

Change in assumption	US$m
Discount rate: increase of 1%3	17
Discount rate: decrease of 1%3	(19)
Oil price[1] increase of 10%	650
Oil price[1] decrease of 10%	(650)
Gas price[2] increase of 10%	(318)
Gas price[2] decrease of 10%	318

1. Long-term oil prices are based on US$65/bbl (2020 real terms) from 2025 and prices are escalated at 2.0% onwards.
2. Long-term gas prices are based on US$3.0/MMBtu (2020 real terms) from 2025 to 2030 and thereafter, US$3.5/MMBtu (2020 real terms). All prices are escalated at 2.0%.
3. A change of 1% represents 100 basis points.

D.6 Other financial assets and liabilities

	2020 US$m	2019 US$m
Other financial assets		
Financial instruments at fair value through profit and loss		
Derivative financial instruments designated as hedges	31	-
Other financial assets	195	63
Total other financial assets	226	63
Current	172	28
Non-current	54	35
Net carrying amount	226	63
Other financial liabilities		
Financial instruments at fair value through profit and loss		
Derivative financial instruments designated as hedges	68	7
Other financial liabilities	3	20
Total other financial liabilities	71	27
Current	37	12
Non-current	34	15
Net carrying amount	71	27

Recognition and measurement

Other financial assets and liabilities

Receivables subject to provisional pricing adjustments are initially recognised at the transaction price and subsequently measured at fair value with movements recognised in the income statement.

Derivative financial instruments

Derivative financial instruments that are designated within qualifying hedge relationships are initially recognised at fair value on the date the contract is entered into. For relationships designated as fair value hedges, subsequent fair value movements of the derivative are recognised in the income statement. For relationships designated as cash flow hedges, subsequent fair value movements of the derivative for the effective portion of the hedge are recognised in other comprehensive income and accumulated in reserves in equity; fair value movements for the ineffective portion are recognised immediately in the income statement. Costs of hedging have been separated from the hedging arrangements and deferred to other comprehensive income and accumulated in reserves in equity. Amounts accumulated in equity are reclassified to the income statement in the periods when the hedged item affects profit or loss.

Fair value

Except for the other financial assets and other financial liabilities set out in this note, there are no material financial assets or financial liabilities carried at fair value. The fair value of derivative financial instruments is determined based on observable quoted forward pricing and swap rates and is classified as Level 2 on the fair value hierarchy. The fair values of other financial assets and other financial liabilities are predominantly determined based on observable quoted forward pricing and are predominantly classified as Level 2 on the fair value hierarchy.

D.6 Other financial assets and liabilities (cont.)

Foreign exchange

The Group had no material other financial assets and liabilities denominated in currencies other than US dollars.

Derivatives and hedging activities

During the period, the Group hedged a percentage of its exposure to commodity price risk, entering into 13.4 million barrels of oil swap derivatives to achieve a minimum average sales price of $33 per barrel. The Group also entered into 7.9 million barrels of oil call options, to take advantage of increases in oil prices above $40 per barrel, for a premium of $37 million. Most of the derivatives settled between April 2020 and December 2020, with swaps and options for 1.3 million barrels of oil not yet settled as at period end. The swaps and call options were designated as cash flow hedges.

The Group also has the following hedging relationships which are exposed to interest rate benchmarks impacted by the Interest Rate Benchmark Reform:

- Interest rate swaps were entered into in the period to hedge the LIBOR interest rate risk associated with the $600 million syndicated facility (refer to Note C.2). The interest rate swaps were designated as cash flow hedges, converting the variable interest into fixed interest US dollar debt, and mature in 2027.
- The Group has a fixed rate 175 million Swiss Franc (CHF) denominated medium term note, which it hedges with cross-currency interest rate swaps designated in both fair value and cash flow hedge relationships. The cross-currency interest rate swaps are referenced to LIBOR.

For relationships designated as cash flow hedges, a loss for the period of $136 million has been recognised in the hedging reserve within equity and losses of $52 million have been reclassified to profit and loss. $1 million has been recognised in profit and loss for hedge ineffectiveness.

The Group early adopted AASB 2019-3 in the prior financial year. This Accounting Standard amended AASB 9 *Financial Instruments* (AASB 9) to provide temporary relief from applying specific hedge accounting requirements to hedge relationships directly affected by interest rate benchmark reforms. The relief provided by the amendment to AASB 9 allows the Group to assume that the interest rate benchmark component at initial designation is separately identifiable and that the interest rate benchmark rate is not altered for the purposes of assessing the economic relationship between the hedged item and the hedging instrument.

Key estimates and judgements

Fair value of other financial assets and liabilities

Estimates have been applied in the measurement of other financial assets and liabilities and, where required, judgement is applied in the settlement of any financial assets or liabilities. In the current period, this included a $12 million periodic adjustment which decreased other financial liabilities, reflecting the arrangements governing Wheatstone LNG sales (2019: $81 million).

D.7 Leases

	Land and buildings US$m	Plant and equipment US$m	Marine vessels and carriers US$m	Total US$m
Lease assets				
Year ended 31 December 2020				
Carrying amount at 1 January 2020	396	-	552	948
Additions	24	-	102	126
Lease remeasurements	1	-	4	5
Depreciation	(29)	-	(66)	(95)
Carrying amount at 31 December 2020	392	-	592	984
At 31 December 2020				
Historical cost	447	-	718	1,165
Accumulated depreciation and impairment	(55)	-	(126)	(181)
Net carrying amount	392	-	592	984
Lease liabilities				
Year ended 31 December 2020				
At 1 January 2020	431	-	739	1,170
Additions	24	3	107	134
Repayments (principal and interest)	(34)	-	(123)	(157)
Accretion of interest	23	-	63	86
Lease remeasurements	40	-	5	45
Carrying amount at 31 December 2020	484	3	791	1,278
Current	16	1	77	94
Non-current	468	2	714	1,184
Carrying amount at 31 December 2020	484	3	791	1,278
Lease assets				
Year ended 31 December 2019				
Carrying amount at 1 January 2019	429	-	600	1,029
Additions	1	-	12	13
Lease remeasurements	(8)	-	-	(8)
Depreciation	(26)	-	(60)	(86)
Carrying amount at 31 December 2019	396	-	552	948
At 31 December 2019				
Historical cost	430	-	612	1,042
Accumulated depreciation and impairment	(34)	-	(60)	(94)
Net carrying amount	396	-	552	948
Lease liabilities				
Year ended 31 December 2019				
At 1 January 2019	444	-	758	1,202
Additions	6	-	12	18
Repayments (principal and interest)	(32)	-	(98)	(130)
Accretion of interest	23	-	66	89
Lease remeasurements	(10)	-	1	(9)
Carrying amount at 31 December 2019	431	-	739	1,170
Current	9	-	60	69
Non-current	422	-	679	1,101
Carrying amount at 31 December 2019	431	-	739	1,170

D.7 Leases (cont.)

Recognition and measurement

When a contract is entered into, the Group assesses whether the contract contains a lease. A lease arises when the Group has the right to direct the use of an identified asset which is not substitutable and to obtain substantially all economic benefits from the use of the asset throughout the period of use. The leases recognised by the Group predominantly relate to LNG vessels and property.

The Group separates the lease and non-lease components of the contract and accounts for these separately. The Group allocates the consideration in the contract to each component on the basis of their relative stand-alone prices.

Leases as a lessee

Lease assets and lease liabilities are recognised at the lease commencement date, which is when the assets are available for use. The assets are initially measured at cost, which is the present value of future lease payments adjusted for any lease payments made at or before the commencement date, plus any make-good obligations and initial direct costs incurred.

Lease assets are depreciated using the straight-line method over the shorter of their useful life and the lease term. Refer to Note B.3 for the useful lives of assets. Periodic adjustments are made for any re-measurements of the lease assets and for impairment losses, assessed in accordance with the Group's impairment policies.

Lease liabilities are initially measured at the present value of future minimum lease payments, discounted using the Group's incremental borrowing rate if the rate implicit in the lease cannot be readily determined, and are subsequently measured at amortised cost using the effective interest rate. Minimum lease payments are fixed payments or index-based variable payments incorporating the Group's expectations of extension options and do not include non-lease components of a contract. A portfolio approach was taken when determining the implicit discount rate for five LNG vessels with similar terms and conditions on transition.

The lease liability is remeasured when there are changes in future lease payments arising from a change in rates, index or lease terms from exercising an extension or termination option. A corresponding adjustment is made to the carrying amount of the lease assets, with any excess recognised in the consolidated income statement.

There are no restrictions placed upon the lessee by entering into these leases.

Short-term leases and leases of low value

Short-term leases (lease term of 12 months or less) and leases of low value assets are recognised as incurred as an expense in the consolidated income statement. Low value assets comprise plant and equipment.

Foreign exchange risk

The Group held $518 million of lease liabilities at 31 December 2020 (2019: $461 million) in currencies other than the US dollar (predominantly Australian dollars).

Maturity profile of lease liabilities

The table below presents the contractual undiscounted cash flows associated with the Group's lease liabilities, representing principal and interest. The figures will not necessarily reconcile with the amounts disclosed in the consolidated statement of financial position.

	2020 US$m	2019 US$m
Due for payment in:		
1 year or less	184	154
1-2 years	181	154
2-3 years	180	150
3-4 years	174	149
4-5 years	174	148
More than 5 years	994	1,045
	1,887	1,800

Lease commitments

The table below presents the contractual undiscounted cash flows associated with the Group's future lease commitments for non-cancellable leases not yet commenced, representing principal and interest.

	2020 US$m	2019 US$m
Due for payment:		
Within one year	90	24
After one year but not more than five years	365	130
Later than five years	45	73
	500	227

Payments of $101 million (2019: $64 million) for short-term leases (lease term of 12 months or less) and payments of $17 million (2019: $14 million) for leases of low value assets were expensed in the consolidated income statement.

The Group has short-term and low value lease commitments for marine vessels and carriers, property, drill rigs and plant and equipment contracted for, but not provided for in the financial statements, of $94 million (2019: $74 million).

Key estimates and judgements

(a) Control

Judgement is required to assess whether a contract is or contains a lease at inception by assessing whether the Group has the right to direct the use of the identified asset and obtain substantially all the economic benefits from the use of that asset.

(b) Lease term

Judgement is required when assessing the term of the lease and whether to include optional extension and termination periods. Option periods are only included in determining the lease term at inception when they are reasonably certain to be exercised. Lease terms are reassessed when a significant change in circumstances occurs. On this basis, possible additional lease payments amounting to $1,670 million (2019: $1,768 million) were not included in the measurement of lease liabilities.

(c) Interest in joint arrangements

Judgement is required to determine the Group's rights and obligations for lease contracts within joint operations, to assess whether lease liabilities are recognised gross (100%) or in proportion to the Group's participating interest in the joint operation. This includes an evaluation of whether the lease arrangement contains a sublease with the joint operation.

(d) Discount rates

Judgement is required to determine the discount rate, where the discount rate is the Group's incremental borrowing rate if the rate implicit in the lease cannot be readily determined. The incremental borrowing rate is determined with reference to the Group's borrowing portfolio at the inception of the arrangement or the time of the modification.

In this section

This section addresses information on items which require disclosure to comply with Australian Accounting Standards and the Australian *Corporations Act 2001*, however are not considered critical in understanding the financial performance or position of the Group.
This section includes Group structure information and other disclosures.

E.1 Contingent liabilities and assets

	2020 US$m	2019 US$m
Contingent liabilities at reporting date		
Not otherwise provided for in the financial statements:		
Contingent liabilities	587	505
Guarantees	10	9
	597	514

Contingent liabilities relate predominantly to possible obligations whose existence will only be confirmed by the occurrence or non-occurrence of uncertain future events, and therefore the Group has not provided for such amounts in these financial statements. Additionally, there are a number of other claims and possible claims that have arisen in the course of business against entities in the Group, the outcome of which cannot be estimated at present and for which no amounts have been included in the table above.

Included in the table above are contingent payments totalling $450 million (31 December 2019: $450 million) that are due on a positive final investment decision to develop the Scarborough field and the contingent payments of up to $100 million on the Sangomar development, dependant on commodity prices and the timing of first oil (refer to Note B.5 for more details).

Additionally, the Group has issued guarantees relating to workers' compensation liabilities.

There were no contingent assets as at 31 December 2020 or 31 December 2019.

E.2 Employee benefits

(a) Employee benefits

	2020 US$m	2019 US$m
Employee benefits	252	246
Share-based payments	19	21
Defined contribution plan costs	27	28
Defined benefit plan expense	2	1
	300	296

Employee benefits for the reporting period are as follows:

Recognition and measurement

The Group's accounting policy for employee benefits other than superannuation is set out in Note D.5. The policy relating to share-based payments is set out in Note E.2(c).

All employees of the Group are entitled to benefits on retirement, disability or death from the Group's superannuation plan.
The majority of employees are party to a defined contribution scheme and receive fixed contributions from Group companies and the Group's legal or constructive obligation is limited to these contributions. Contributions to defined contribution funds are recognised as an expense as they become payable. Prepaid contributions are recognised as an asset to the extent that a cash refund or a reduction in the future payment is available.
The Group also operates a defined benefit superannuation scheme, the membership of which is now closed. The net defined benefit plan asset at 31 December 2020 was $19 million (2019: $18 million).

(b) Compensation of key management personnel

Key management personnel (KMP) compensation for the financial year was as follows:

	2020 US$	2019 US$
Short-term employee benefits	5,868,476	6,416,430
Post-employment benefits	63,805	71,137
Share-based payments	7,201,653	7,253,672
Long-term employee benefits	515,585	281,882
Termination benefits	390,087	-
	14,039,606	14,023,121

(c) Share plans

The Group provides benefits to its employees (including KMP) in the form of share-based payments whereby employees render services for shares (equity-settled transactions).

Woodside equity plan (WEP) and supplementary Woodside equity plan (SWEP)

The WEP is available to all permanent employees, but since 1 January 2018 has excluded EIS participants. The number of Equity Rights (ERs) offered to each eligible employee is calculated with reference to salary and performance. The linking of performance to an allocation allows the Group to recognise and reward eligible employees for high performance. The ERs have no further ongoing performance conditions after allocation, and do not require participants to make any payment in respect of the ERs at grant or at vesting.

Each ER relating to the WEP for 2018 and prior years entitles the participant to receive a Woodside share on a vesting date three years after the grant date. From the 2019 WEP onwards, 75% of the ERs offered to each participant will vest three years after the grant date, with the remaining 25% vesting five years after the grant date.

The SWEP award is available to employees identified as being retention critical. Each ER entitles the participant to receive a Woodside share on the vesting date three years after the effective grant date. Participants do not make any payment in respect of the ERs at grant or at vesting.

Executive incentive plans (EIP)

The EIP operated as Woodside's Executive incentive framework until the end of 2017, after which the Board introduced the EIS. The EIP was used to deliver short-term award (STA) and long-term award (LTA) to Senior Executives.

Short-term awards (STA)

STAs were delivered in the form of restricted shares to executives, including all executive KMP. There are no further performance conditions for vesting of deferred STA. Participants are not required to make any payments in respect of STA awards at grant or at vesting. Restricted shares entitle their holders to receive dividends.

Long-term awards (LTA)

LTAs were granted in the form of Variable Pay Rights (VPRs) to executives, including all executive KMP. Vesting of LTA is subject to achievement of relative total shareholder return (RTSR) targets, with 33% measured against the ASX 50 and the remaining 67% tested against an international group of oil and gas companies.

Participants are not entitled to receive dividends and are not required to make any payments in respect of LTA awards at grant or at vesting.

E.2 Employee benefits (cont.)

Executive incentive scheme (EIS)

The EIS was introduced for the 2018 performance year for all executives including executive KMP. The EIS is delivered in the form of a cash incentive, Restricted Shares and Performance Rights. The grant date of the Restricted Shares and Performance Rights has been determined to be subsequent to the performance year, being the date of the Board of Directors' approval. Accordingly, the 2020 Restricted Shares and Performance Rights have not been included in the table below as they have not been approved as at 31 December 2020. An expense related to the 2020 performance year has been estimated for Restricted Shares and Performance Rights, using fair value estimates based on inputs at 31 December 2020.

The Restricted Shares and Performance Rights relating to the 2019 performance year were granted on 12 February 2020 and have been included in the table below. The expense estimated as at 31 December 2019 in relation to the 2019 performance year was updated to the fair value on grant date during the period.

Recognition and measurement

All compensation under WEP, SWEP and executive share plans is accounted for as share-based payments to employees for services provided. The cost of equity-settled transactions with employees is measured by reference to the fair values of the equity instruments at the date at which they are granted. The fair value of share-based payments is recognised, together with the corresponding increase in equity, over the period in which the vesting conditions are fulfilled, ending on the date on which the relevant employee becomes fully entitled to the shares. At each balance sheet date, the Group reassesses the number of awards that are expected to vest based on service conditions. The expense recognised each year takes into account the most recent estimate.

The fair value of the benefit provided for the WEP and SWEP is estimated using the Black-Scholes option pricing technique. The fair value of the restricted shares is estimated as the closing share price at grant date. The fair value of the benefit provided for the RTSR VPRs was estimated using the Binomial or Black-Scholes option pricing technique combined with a Monte Carlo simulation methodology, where relevant, using historical volatility to estimate the volatility of the share price in the future.

The number of awards and movements for all share plans are summarised as follows:

	Number of awards			
	Employee plans		Executive plans	
	WEP	SWEP	Short-term awards[3]	Long-term awards[3]
Year ended 31 December 2020				
Opening balance	6,911,551	17,678	867,716	2,704,143
Granted during the year[1,2]	1,127,546	-	373,774	617,091
Vested during the year	(1,943,777)	(17,678)	(257,489)	(242,608)
Forfeited during the year	(476,717)	-	(8,706)	(280,321)
Awards at 31 December 2020	5,618,603	-	975,295	2,798,305
	US$m	US$m	US$m	US$m
Fair value of awards granted during the year	13	-	9	12

	Number of awards			
	Employee plans		Executive plans	
	WEP	SWEP	Short-term awards[3]	Long-term awards[3]
Year ended 31 December 2019				
Opening balance	6,325,364	17,678	813,968	2,545,915
Granted during the year[1,2]	2,537,991	-	417,166	731,799
Vested during the year	(1,645,915)	-	(338,537)	(212,694)
Forfeited during the year	(305,889)	-	(24,881)	(360,877)
Awards at 31 December 2019	6,911,551	17,678	867,716	2,704,143
	US$m	US$m	US$m	US$m
Fair value of awards granted during the year	47	-	10	15

1. For the purpose of valuation, the share price on grant date for the 2020 WEP allocations was $12.57 (2019: $21.72).
2. For the purpose of valuation, the share price on grant date for the 2020 Restricted Shares was $22.76 (2019: $24.71) and the 2020 Performance Rights was $15.81 (2019: $16.87).
3. Includes awards issued under EIP and EIS.

For more detail on these share plans and performance rights issued to KMPs, refer to the Remuneration Report on pages 59-82.

E.3 Related party transactions

Transactions with directors

There were no transactions with directors during the year. Key management personnel compensation is disclosed in Note E.2(b).

E.4 Auditor remuneration

The auditor of Woodside Petroleum Ltd is Ernst & Young (EY).

	2020 US$000	2019 US$000
Amounts received or due and receivable to:		
Ernst & Young (Australia)		
Audit of the financial reports of the Group and controlled entities	1,521	1,574
Other assurance and agreed-upon procedures services	110	276
Other services	164	298
	1,795	2,148
Other overseas member firms of Ernst & Young (Australia)		
Audit of the financial reports of controlled entities	165	193
Other assurance and agreed-upon procedures services	30	192
Other services	14	14
	209	399

E.5 Events after the end of the reporting period

- On 10 February 2021, the Group redeemed the $700 million 2021 US bond (refer to Note C.2 for more details).
- Woodside is monitoring the situation in Myanmar following the political developments that occurred subsequent to the reporting period. It is not currently possible to determine the impact, if any, of these events on the carrying value of the Group's Myanmar exploration and evaluation assets.

E.6 Joint arrangements

(a) Interest percentage in joint ventures

		Group Interest %	
Entity	Principal activity	2020	2019
North West Shelf Gas Pty Ltd	Marketing services for ventures in the sale of gas to the domestic market.	16.67	16.67
North West Shelf Liaison Company Pty Ltd	Liaison for ventures in the sale of LNG to the Japanese market.	16.67	16.67
China Administration Company Pty Ltd	Marketing services for ventures in the sale of LNG to international markets.	16.67	16.67
North West Shelf Shipping Service Company Pty Ltd	LNG vessel fleet advisor.	16.67	16.67
North West Shelf Lifting Coordinator Pty Ltd	Coordinator for venturers for all equity liftings.	16.67	16.67

(b) Interest percentage in joint operations

	Group Interest %	
	2020	2019
Producing and developing assets		
Oceania		
North West Shelf	12.5 - 50.0	12.5 - 50.0
Greater Enfield and Vincent	60.0	60.0
Stybarrow	50.0	50.0
Balnaves	65.0	65.0
Pluto	90.0	90.0
Wheatstone	13.0 - 65.0	13.0 - 65.0
Africa		
Senegal[1]	68.3	35.0
Exploration and evaluation assets		
Oceania		
Browse Basin	30.6	30.6
Carnarvon Basin[2,3]	15.8 - 73.5	15.8 - 90.0
Bonaparte Basin	26.7 - 35.0	26.7 - 35.0
Africa		
Congo[4]	42.5	-
Senegal[1]	75.0	35.0
The Americas		
Peru[5]	-	35.0
Kitimat	50.0	50.0
Asia		
Republic of Korea	50.0	50.0
Myanmar[6]	40.0 - 50.0	40.0 - 50.0
Europe		
Ireland	90.0	90.0
Bulgaria	30.0	30.0

1. Includes the acquisition of Cairn's 36.44% participating interest in the RSSD Joint Venture, increasing Woodside's interest to 68.33% in the exploitation area and 75% in the exploration area. Following the completion of the acquisition of FAR's interest in the RSSD Joint Venture, Woodside's participating interest will increase to 82% in the exploitation area and 90% in the exploration area (refer to Note B.5 for more details).
2. Scarborough is included in the Carnarvon Basin.
3. Titles surrendered for WA-271-P, WA-428-P and WA-483-P, title transferred for WA-520-P in 2020 and title surrendered for WA-430-P (Ragnar/Toro) and then converted to retention leases WA-93-R and WA-94-R in 2020.
4. Production Sharing Contract awarded in 2020. Woodside holds a 42.5% working interest in Congo Marine XX.
5. Expiration of Block 108 licence in 2020.
6. Expiration of licence for Myanmar Blocks AD-6 in 2020.

The principal activities of the joint operations above are exploration, development and production of hydrocarbons.

Key estimates and judgements

Accounting for interests in other entities

Judgement is required in assessing the level of control obtained in a transaction to acquire an interest in another entity; depending upon the facts and circumstances in each case, Woodside may obtain control, joint control or significant influence over the entity or arrangement. Judgement is applied when determining the relevant activities of a project and if joint control is held over them.

Relevant activities include, but are not limited to, work program and budget approval, investment decision approval, voting rights in joint operating committees, amendments to permits and changes to joint arrangement participant holdings. Transactions which give Woodside control of a business are business combinations. If Woodside obtains joint control of an arrangement, judgement is also required to assess whether the arrangement is a joint operation or a joint venture.

If Woodside has neither control nor joint control, it may be in a position to exercise significant influence over the entity, which is then accounted for as an associate.

E.6 Joint arrangements (cont.)

Recognition and measurement

Joint arrangements are arrangements in which two or more parties have joint control. Joint control is the contractual agreed sharing of control of the arrangement which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control. Joint arrangements are classified as either a joint operation or joint venture, based on the rights and obligations arising from the contractual obligations between the parties to the arrangement.

To the extent the joint arrangement provides the Group with rights to the individual assets and obligations arising from the joint arrangement, the arrangement is classified as a joint operation, and as such the Group recognises its:

- assets, including its share of any assets held jointly;
- liabilities, including its share of any liabilities incurred jointly;
- revenue from the sale of its share of the output arising from the joint operation;
- share of revenue from the sale of the output by the joint operation; and
- expenses, including its share of any expenses incurred jointly.

To the extent the joint arrangement provides the Group with rights to the net assets of the arrangement, the investment is classified as a joint venture and accounted for using the equity method.

Joint arrangements acquired which are deemed to be carrying on a business are accounted for applying the principles of AASB 3 *Business Combinations*. Joint arrangements which are not deemed to be carrying on a business are treated as asset acquisitions.

E.7 Parent entity information

	2020 US$m	2019 US$m
Woodside Petroleum Ltd:		
Current assets	444	404
Non-current assets	10,257	9,949
Current liabilities	-	(133)
Non-current liabilities	(579)	(484)
Net Assets	10,122	9,736
Issued and fully paid shares	9,297	9,010
Shares reserved for employee share plans	(23)	(39)
Employee benefits reserve	117	120
Foreign currency translation reserve	296	296
Distributable profits reserve	462	-
Retained earnings	(27)	349
Total shareholders equity	10,122	9,736
Profit of parent entity	852	1,288
Total comprehensive income of parent entity	852	1,288

Guarantees

Woodside Petroleum Ltd and Woodside Energy Ltd (a subsidiary company) are parties to a Deed of Cross Guarantee as disclosed in Note E.8. The effect of the Deed is that Woodside Petroleum Ltd has guaranteed to pay any deficiency in the event of winding up of the subsidiary company under certain provisions of the *Corporations Act 2001*. The subsidiary company has also given a similar guarantee in the event that Woodside Petroleum Ltd is wound up.

Woodside Petroleum Ltd has guaranteed the discharge by a subsidiary company of its financial obligations under debt facilities disclosed in Note C.2. Woodside Petroleum Ltd has guaranteed certain obligations of subsidiaries to unrelated parties on behalf of their performance in contracts. No liabilities are expected to arise from these guarantees.

E.8 Subsidiaries

(a) Subsidiaries

Name of entity	Notes
Ultimate Parent Entity	
Woodside Petroleum Ltd	(1,2,3)
Subsidiaries	
Company name	
Woodside Energy Ltd	(2,3,4)
Woodside Browse Pty Ltd	(2,4)
Woodside Burrup Pty Ltd	(2,4)
Burrup Facilities Company Pty Ltd	(5)
Burrup Train 1 Pty Ltd	(5)
Pluto LNG Pty Ltd	(5)
Woodside Burrup Train 2 A Pty Ltd	(2,4)
Woodside Burrup Train 2 B Pty Ltd	(2,4)
Woodside Energy (LNG Fuels and Power) Pty Ltd	(2,4)
Woodside Energy (Domestic Gas) Pty Ltd	(2,4)
Woodside Energy (Algeria) Pty Ltd	(2,4)
Woodside Energy Australia Asia Holdings Pte Ltd y	(4)
Woodside Energy Holdings International Pty Ltd	(2,4)
Woodside Energy Mediterranean Pty Ltd	(2,4)
Woodside Energy International (Canada) Limited t	(4)
Woodside Energy (Canada LNG) Limited t	(4)
Woodside Energy (Canada PTP) Limited t	(4)
KM LNG Operating General Partnership t	(4,8)
KM LNG Operating Ltd t	(4)
Woodside Energy Holdings Pty Ltd	(2,4)
Woodside Energy Holdings (USA) Inc q	(4)
Woodside Energy (USA) Inc q	(4)
Gryphon Exploration Company q	(4)
Woodside Energy (Cameroon) SARL ■	(4)
Woodside Energy (Gabon) Pty Ltd	(2,4)
Woodside Energy (Indonesia) Pty Ltd	(2,4)
Woodside Energy (Indonesia II) Pty Ltd	(2,4)
Woodside Energy (Indonesia III) Pty Ltd	(2,4)
Woodside Energy (Ireland) Pty Ltd	(2,4)
Woodside Energy (Korea) Pte Ltd y	(4)
Woodside Energy (Korea II) Pte Ltd y	(4)
Woodside Energy (Myanmar) Pte Ltd y	(4)
Woodside Energy (Morocco) Pty Ltd	(2,4)
Woodside Energy (New Zealand) Limited z	(4)
Woodside Energy (New Zealand 55794) Limited z	(4)
Woodside Energy (Peru) Pty Ltd	(2,4)
Woodside Energy (Senegal) Pty Ltd	(2,4)
Woodside Energy (Tanzania) Limited ¥	(6)
Woodside Energy Holdings II Pty Ltd	(2,4)
Woodside Power Pty Ltd	(2,4)
Woodside Power (Generation) Pty Ltd	(2,4)
Woodside Energy Holdings (South America) Pty Ltd	(2,4)
Woodside Energia (Brasil) Apoio Administrativo Ltda ●	(7)
Woodside Energy Holdings (UK) Pty Ltd	(2,4)
Woodside Energy (UK) Limited p	(4)
Woodside Energy Finance (UK) Limited p	(4)
Woodside Energy (Congo) Limited p	(4)
Woodside Energy (Bulgaria) Limited p	(4)
Woodside Energy Holdings (Senegal) Limited p	(4)
Woodside Energy (Senegal) B.V. □	(4)
Woodside Energy (France) SAS ⭘	(4)
Woodside Energy Iberia S.A. °	(4)
Woodside Energy (N.A.) Ltd p	(4)
Woodside Energy Services (Qingdao) Co Ltd ◆	(4,10)
Woodside Energy Julimar Pty Ltd	(2,4)
Woodside Energy (Norway) Pty Ltd	(2,4)
Woodside Energy Technologies Pty Ltd	(2,4,9)
Woodside Technology Solutions Pty Ltd	(2,4,11)
Woodside Energy Trading Singapore Pte Ltd y	(4)
WelCap Insurance Pte Ltd y	(4)
Woodside Energy Shipping Singapore Pte Ltd y	(4)
Metasource Pty Ltd	(2,4)
Mermaid Sound Port and Marine Services Pty Ltd	(2,4)
Woodside Finance Limited	(2,4)
Woodside Petroleum (Timor Sea 19) Pty Ltd	(2,4)
Woodside Petroleum (Timor Sea 20) Pty Ltd	(2,4)
Woodside Petroleum Holdings Pty Ltd	(2,4)

1. Woodside Petroleum Ltd is the ultimate holding company and the head entity within the tax consolidated group.
2. These companies were members of the tax consolidated group at 31 December 2020.
3. Pursuant to ASIC Instrument 2016/785, relief has been granted to the controlled entity, Woodside Energy Ltd, from the Corporations Act 2001 requirements for the preparation, audit and publication of accounts. As a condition of the Instrument, Woodside Petroleum Ltd and Woodside Energy Ltd are parties to a Deed of Cross Guarantee.
4. All subsidiaries are wholly owned except those referred to in Notes 5, 6, 7 and 8.
5. Kansai Electric Power Australia Pty Ltd and Tokyo Gas Pluto Pty Ltd each hold a 5% interest in the shares of these subsidiaries. These subsidiaries are controlled.
6. As at 31 December 2020, Woodside Energy Holdings Pty Ltd held a 99.99% interest in the shares of Woodside Energy (Tanzania) Limited and Woodside Energy Ltd held the remaining 0.01% interest.
7. As at 31 December 2020, Woodside Energy Holdings (South America) Pty Ltd held a 99.99% interest in the shares of Woodside Energia (Brasil) Apoio Administrativo Ltda and Woodside Energy Ltd held the remaining 0.01% interest.
8. As at 31 December 2020, Woodside Energy International (Canada) Limited and Woodside Energy (Canada LNG) Limited were the general partners of the KM LNG Operating General Partnership holding a 99.99% and 0.01% partnership interest, respectively.
9. Woodside Energy Technologies Pty Ltd owns 30% in Blue Ocean Seismic Services Limited which is accounted for as an investment in associate.
10. Woodside Energy Services (Qingdao) Co Ltd was incorporated on 16 July 2020.
11. Woodside Technology Solutions Pty Ltd was incorporated on 27 August 2020.

All subsidiaries were incorporated in Australia unless identified with one of the following symbols:

● Brazil	□ The Netherlands	¥ Tanzania
■ Cameroon	z New Zealand	p England and Wales
t Canada	y Singapore	q USA
⭘ France	° Spain	◆ China

Classification

Subsidiaries are all the entities over which the Group has the power over the investee such that the Group is able to direct the relevant activities, has exposure, or rights, to variable returns from its involvement with the investee and has the ability to use its power over the investee to affect the amount of the investor's returns.

E.8 Subsidiaries (cont.)

(b) Subsidiaries with material non-controlling interests

The Group has two Australian subsidiaries with material non-controlling interests (NCI).

Name of entity	Principal place of business	% held by NCI
Burrup Facilities Company Pty Ltd	Australia	10%
Burrup Train 1 Pty Ltd	Australia	10%

The NCI in both subsidiaries is 10% held by the same parties (refer to Note E.8(a) footnote 5 for details).

The summarised financial information (including consolidation adjustments but before intercompany eliminations) of subsidiaries with material NCI is as follows:

	2020 US$m	2019 US$m
Burrup Facilities Company Pty Ltd		
Current assets	425	423
Non-current assets	5,224	5,185
Current liabilities	(51)	(6)
Non-current liabilities	(571)	(577)
Net assets	5,027	5,025
Accumulated balance of NCI	503	503
Revenue	859	718
Profit	318	263
Profit allocated to NCI	32	26
Dividends paid to NCI	(32)	(48)
Operating	652	492
Investing	(69)	(34)
Financing	(583)	(458)
Net increase/(decrease) in cash and cash equivalents	-	-
Burrup Train 1 Pty Ltd		
Current assets	372	371
Non-current assets	3,081	2,989
Current liabilities	(103)	(71)
Non-current liabilities	(385)	(396)
Net assets	2,965	2,893
Accumulated balance of NCI	297	289
Revenue	1,423	1,189
Profit	208	132
Profit allocated to NCI	21	13
Dividends paid to NCI	(13)	(32)
Operating	473	275
Investing	(2)	(10)
Financing	(471)	(265)
Net increase/(decrease) in cash and cash equivalents	-	-

(c) Deed of Cross Guarantee and Closed Group

Woodside Petroleum Ltd and Woodside Energy Ltd are parties to a Deed of Cross Guarantee under which each company guarantees the debts of the other. By entering into the Deed, the entities have been granted relief from the *Corporations Act 2001* requirements for the preparation, audit and publication of accounts, pursuant to ASIC Instrument 2016/785. The two entities represent a Closed Group for the purposes of the Instrument.

The consolidated income statement and statement of financial position of the members of the Closed Group are set out below:

	2020 US$m	2019 US$m
Closed Group Consolidated Income Statement and Statement of Retained Earnings		
Profit/(loss) before tax	(3,195)	3,471
Tax benefit	955	33
Profit/(loss) after tax	(2,240)	3,504
Retained earnings at the beginning of the financial year	3,579	1,261
Transfer of retained earnings to distributable profits reserve	(710)	-
Adoption of AASB 16 (net of tax)	-	3
Dividends	(518)	(1,189)
Retained earnings at the end of the financial year	111	3,579
Closed Group Consolidated Statement of Financial Position		
Current assets		
Cash and cash equivalents	131	93
Receivables	488	445
Inventories	46	62
Other financial assets	118	9
Other assets	20	18
Total current assets	803	627
Non-current assets		
Receivables	29	23
Inventories	19	-
Other financial assets	31,771	30,250
Exploration and evaluation assets	1,059	1,634
Oil and gas properties	2,688	4,101
Other plant and equipment	185	176
Deferred tax assets	580	38
Lease assets	340	360
Total non-current assets	36,671	36,582
Total assets	37,474	37,209
Current liabilities		
Payables	156	313
Other financial liabilities	46	22
Other liabilities	48	46
Provisions	261	238
Tax payable	-	133
Lease liabilities	24	17
Total current liabilities	535	769
Non-current liabilities		
Payables	24,570	20,974
Deferred tax liabilities	-	507
Other financial liabilities	-	15
Other liabilities	12	20
Provisions	1,272	1,143
Lease liabilities	392	360
Total non-current liabilities	26,246	23,019
Total liabilities	26,781	23,788
Net assets	10,693	13,421
Equity		
Issued and fully paid shares	9,297	9,010
Shares held for employee share plan	(23)	(39)
Other reserves	1,308	871
Retained earnings	111	3,579
Total equity	10,693	13,421

E.9 Other accounting policies

(a) Summary of other significant accounting policies

Tax consolidation

The parent and its wholly owned Australian controlled entities have elected to enter a tax consolidation, with Woodside Petroleum Ltd as the head entity of the tax consolidated group. The members of the tax consolidated group are identified in Note E.8(a).

The tax expense/benefit, deferred tax liabilities and deferred tax assets arising from temporary differences of the members of the tax consolidated group are recognised in the separate financial statements of the members of the tax consolidated group, using the stand-alone approach.

Entities within the tax consolidated group have entered into a tax funding arrangement and a tax sharing agreement with the head entity. Under the tax funding agreement, Woodside Petroleum Ltd and each of the entities in the tax consolidated group have agreed to pay or receive a tax equivalent payment to or from the head entity, based on the current tax liability or current tax asset of the entity.

The tax sharing agreement entered into between members of the tax consolidated group provides for the determination of the allocation of income tax liabilities between the entities, should the head entity default on its tax payment obligations. No amounts have been recognised in the financial statements in respect of this agreement as payment of any amounts under the tax sharing agreement is considered remote.

(b) New and amended accounting standards and interpretations issued but not yet effective

A number of new standards, amendments of standards and interpretations have recently been issued but are not yet effective and have not been adopted by the Group as at the financial reporting date.

The Group has reviewed these standards and interpretations and has determined that none of the new or amended standards will significantly affect the Group's accounting policies, financial position or performance.

(c) New and amended accounting standards and interpretations adopted

The Group adopted AASB 2018-6 *Amendments to Australian Accounting Standards – Definition of a Business* as of 1 January 2020.

The standard makes amendments to AASB 3 *Business Combinations* and provides a simplified assessment (including clarification of minimum requirements) of what represents a business, and introduces an optional 'concentration test', which limits the identification of a business to where there is a substantial concentration of fair value within a single asset or group of assets.

The Group applied the amended definition of a business to determine the accounting treatment of the significant production and growth asset acquisition completed during the period. The Group concluded that the transaction is an asset acquisition. For more details, refer to Note B.5.

A number of other new standards are also effective from 1 January 2020 but they do not have a material effect on the Group's financial statements.

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Independent auditor's report to the members of Woodside Petroleum Ltd

Report on the audit of the financial report

Opinion

We have audited the financial report of Woodside Petroleum Ltd (the Company) and its subsidiaries (collectively the Group), which comprises the consolidated statement of financial position as at 31 December 2020, the consolidated income statement, the consolidated statement of comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, notes to the financial statements, including a summary of significant accounting policies, and the directors' declaration.

In our opinion, the accompanying financial report of the Group is in accordance with the *Corporations Act 2001*, including:

a) giving a true and fair view of the Group's financial position as at 31 December 2020 and of its financial performance for the year ended on that date.

b) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report. We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial report of the current year. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, but we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the financial report* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the financial report. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying financial report.

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1. Impairment of oil and gas properties

Why significant	How our audit addressed the key audit matter
Australian Accounting Standards require the Group to assess whether there are any indicators that oil and gas properties may be impaired. If an indicator exists, the Group must estimate the recoverable amount of the asset. At 30 June 2020, the Group concluded that there were impairment indicators for all Cash Generating Units (CGUs) and impairment testing was undertaken. The principal indicators of impairment were the decline in oil price and deficit between the net assets and market capitalisation of the Company. The Group undertook impairment testing at 30 June 2020, and recognised an impairment expense of $3,712 million pertaining to oil and gas properties. Key assumptions, judgements and estimates, used in the formulation of the Group's impairment of the oil and gas properties are disclosed in Note B.4. At 31 December 2020, the Group concluded that there were no impairment indicators present for any CGU. The assessment of indicators of impairment and reversal of impairment and the impairment testing process is complex and highly judgemental, and is based on assumptions which are impacted by expected future performance and market conditions. The recoverable amounts of the CGUs are also sensitive to changes in the key assumptions, judgements and estimates used. Accordingly, this matter was considered to be a key audit matter.	We evaluated the Group's consideration of internal and external sources of information in assessing whether indicators of impairment or reversal of impairment existed. Where impairment indicators were present and impairment testing was conducted by the Group, we evaluated the assumptions and methodologies used by the Group and the estimates made in conducting this testing. In particular, we considered those judgements and estimates related to the determination of CGUs, the forecast cash flows and the inputs used to formulate those cash flows such as discount rates, reserves, inflation rates, operating costs, foreign exchange rates and commodity prices. We involved our valuations, modelling and economics specialists to assist in the impairment assessment for the audit. Our audit procedures were undertaken across all CGUs for which impairment indicators were identified. Specifically, we evaluated the discounted cash flow models and other data supporting the Group's assessment. In doing so, we: ▸ considered future production profiles compared to reserves, current approved budgets and historical production, and ensured variations were in accordance with our expectations based upon other information obtained throughout the audit ▸ evaluated commodity prices with reference to contractual arrangements, market prices (where available), broker consensus, analyst views and historical performance ▸ evaluated discount rates, inflation rates and foreign exchange rates with reference to market prices (where available), market indices, broker consensus and historical performance ▸ compared future operating and development expenditure to current sanctioned budgets, historical expenditure and ensured variations were in accordance with our expectations based upon other information obtained throughout the audit ▸ evaluated how the Group's response to climate risk has been reflected in the assessment of the recoverable amount of the CGUs ▸ assessed whether the impairment charge recorded in the financial statements agreed to the underlying impairment testing models ▸ assessed the impact of changes to key assumptions on the recoverable amount of the CGUs ▸ tested the mathematical accuracy of the discounted cash flow models and the sensitivity analysis. We used the work of the Group's internal experts with respect to the hydrocarbon reserve estimates used in the Group's impairment testing. This included understanding the reserve estimation processes carried out, the Group's internal certification process for technical and commercial experts who are responsible for reserves, the design of the Group's Petroleum Resources Management procedures and its alignment with the guidelines prepared by the Society of Petroleum Engineers. We also examined the competence and objectivity of the Group's internal and external experts and the scope and appropriateness of their work. We also considered the adequacy of the financial report disclosures regarding the assumptions, key estimates and judgements applied by management for the Group's impairment assessments, and in respect of sensitivity analysis for CGUs impaired. These disclosures are included in Note B.4.

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2. Impairment assessment of exploration and evaluation (E&E) assets

Why significant	How our audit addressed the key audit matter
The impairment testing process for E&E assets commences with an assessment against indicators of impairment under Australian Accounting Standard - AASB 6 *Exploration for and Evaluation of Mineral Resources*. If there is an indication that an E&E asset may be impaired, the Group is required to estimate the recoverable amount of the asset. At 30 June 2020, the Group identified impairment indicators in respect of a number of E&E assets. Impairment testing was undertaken which resulted in an impairment charge of $1,557 million being recorded. At 31 December 2020, the Group concluded that there were no impairment indicators present for any recognised E&E assets. The key assumptions, judgements and estimates used in the formulation of the Group's impairment assessment of E&E assets, and those used in the determination of the recoverable amount of E&E assets for which indicators of impairment were present, are set out in Note B.4 of the financial report. The assessment of indicators of impairment and, where required, the determination of recoverable amount, is complex and highly judgemental. Accordingly, this matter was considered to be a key audit matter.	We assessed the impairment analysis prepared by the Group, evaluating the assumptions and methodologies used and the estimates made. Our audit procedures included the following: ▸ Considered the Group's right to explore in the relevant exploration area which included obtaining and assessing supporting documentation such as license agreements and correspondence with relevant government agencies ▸ Considered the Group's intention to carry out substantive E&E activity in the relevant exploration area, or plans to move the asset into development. This included assessment of the Group's approved budgets and cashflow forecasts for evidence of planned future activity, and enquiries with senior management as to the intentions and strategy of the Group ▸ Considered the Group's assessment of the commercial viability of results relating to E&E activities carried out in the relevant license area ▸ Assessed the Group's ability to finance both planned future E&E activity and asset development plans ▸ Assessed the capabilities of management's internal experts for the purposes of estimating the potential resources associated with E&E assets ▸ Assessed, in conjunction with our valuation specialists, the key assumptions used in the determination of the recoverable value of the E&E asset, with reference to market information where available ▸ Assessed whether the impairment charge recorded in the financial statements agreed to the Group's assessment of the recoverable amount. We also considered the adequacy of the financial report disclosure of the assumptions, key estimates and judgements applied by management for the Group's assessment of impairment of E&E assets. These have been disclosed in Notes B.2 and B.4 of the financial report.

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3. Accounting for petroleum resources rent tax (PRRT) deferred tax assets

Why significant	How our audit addressed the key audit matter
The consolidated financial statements of the Group include deferred tax assets arising from PRRT. The determination of the quantum, likelihood and timing of the realisation of deferred tax assets arising from PRRT is highly judgemental and is assessed on a basis consistent with the impairment assessment set out above, as well as other factors such as the long term bond rate applied to the augmentation of deductible expenditure. As such, this matter was considered to be a key audit matter. The Group's disclosures about PRRT are included in the summary of significant accounting policies in Note A.5 of the financial report.	We considered the application of the judgements and methodologies used by the Group to calculate the deferred tax assets arising from PRRT and estimate their utilisation in the future. In particular, we assessed those judgements and methodologies relating to the estimation of future PRRT assessable profits, the interpretation of PRRT legislation and the consistency in application of forecast performance with other forecasts made, including cash flow modelling for impairment purposes. We also considered the adequacy of the financial report disclosures regarding PRRT included in Note A.5 of the financial report.

Information other than the financial report and auditor's report thereon

The directors are responsible for the other information. The other information comprises the information included in the Company's Annual Report for the year ended 31 December 2020, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon, with the exception of the Remuneration Report and our related assurance opinion.

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

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

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters relating to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

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Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

As part of an audit in accordance with the Australian Auditing Standards, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.

- Conclude on the appropriateness of the directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial report or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial report, including the disclosures, and whether the financial report represents the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

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working world

From the matters communicated to the directors, we determine those matters that were of most significance in the audit of the financial report of the current year and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on the audit of the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 62 to 81 of the directors' report for the year ended 31 December 2020.

In our opinion, the Remuneration Report of Woodside Petroleum Ltd for the year ended 31 December 2020, complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.

Ernst + Young

Ernst & Young

T S Hammond
Partner
Perth
18 February 2021

ANNEXURE 2 – BHP PETROLEUM HISTORICAL FINANCIAL INFORMATION

a) HISTORICAL FINANCIAL INFORMATION FOR HALF-YEAR ENDED 31 DECEMBER 2021

b) HISTORICAL FINANCIAL INFORMATION FOR HALF-YEAR ENDED 31 DECEMBER 2020

c) HISTORICAL FINANCIAL INFORMATION FOR YEAR END 30 JUNE 2019

d) HISTORICAL FINANCIAL INFORMATION FOR YEAR END 30 JUNE 2020

e) HISTORICAL FINANCIAL INFORMATION FOR YEAR END 30 JUNE 2021

BHP Petroleum Assets

Combined Financial Statements as of and
for the Half Year Ended 31 December 2021

BHP Petroleum Assets

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Financial Statements

BHP Petroleum Assets

Combined statement of profit or loss and comprehensive income or loss for the half year ended 31 December 2021

	Notes	**Half year ended 31 Dec 2021 US$M**	Half year ended 31 Dec 2020 US$M
Revenue	2	**3,198**	1,602
Other income	3	**172**	20
Expenses excluding net finance costs	3	**(1,761)**	(1,816)
Loss from equity accounted investments	11	**(1)**	(5)
Profit/(loss) from operations		**1,608**	(199)
Finance expense		**(124)**	(277)
Finance income		**6**	39
Net finance costs		**(118)**	(238)
Profit/(loss) before taxation		**1,490**	(437)
Income tax (expense)/income	4	**(870)**	34
Royalty - related taxation (net of income tax benefit)	4	**(37)**	16
Total taxation (expense)/income		**(907)**	50
Profit/(loss) after taxation		**583**	(387)
Other comprehensive income or loss			
Items that may be reclassified subsequently to the income statement:			
Exchange fluctuations on transactions of foreign operations taken to equity		**1**	-
Total items that may be reclassified subsequently to the income statement		**1**	-
Total other comprehensive loss		**1**	-
Total comprehensive income/(loss)		**584**	(387)

The accompanying notes form part of these half year financial statements.

BHP Petroleum Assets

Combined statement of financial position as at 31 December 2021

	Notes	31 Dec 2021 US$M	30 June 2021 US$M
ASSETS			
Current assets			
Cash and cash equivalents	9	**992**	776
Trade and other receivables	5	**1,230**	908
Receivables from BHP Group	9,12	**10,852**	5,526
Inventories		**278**	307
Current tax assets		**69**	130
Other		**14**	9
Total current assets		**13,435**	7,656
Non-current assets			
Trade and other receivables	5	**201**	157
Other financial assets	9	**37**	52
Property, plant and equipment		**11,226**	11,854
Intangible assets		**63**	78
Net investments and funding of equity accounted investments	11	**246**	253
Deferred tax assets		**1,947**	2,182
Other		**3**	3
Total non-current assets		**13,723**	14,579
Total assets		**27,158**	22,235
LIABILITIES			
Current liabilities			
Trade and other payables	6	**952**	919
Payables to BHP Group	9,12	**12,552**	2,001
Interest bearing liabilities		**38**	35
Other financial liabilities	9	**60**	9
Current tax payable		**312**	280
Closure and rehabilitation provisions	7	**144**	141
Other provisions	8,10	**216**	315
Deferred income		**16**	14
Total current liabilities		**14,290**	3,714
Non-current liabilities			
Non-current tax payable		**69**	14
Payables to BHP Group	9,12	**-**	10,347
Interest bearing liabilities		**219**	234
Closure and rehabilitation provisions	7	**3,760**	3,816
Deferred tax liabilities		**465**	610
Other provisions	8,10	**341**	344
Deferred income		**40**	44
Total non-current liabilities		**4,894**	15,409
Total liabilities		**19,184**	19,123
Net assets		**7,974**	3,112
EQUITY		**7,974**	3,112

The accompanying notes form part of these half year financial statements.

BHP Petroleum Assets

Combined statement of cash flows for the half year ended 31 December 2021

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Operating activities		
Profit/(loss) before taxation	**1,490**	(437)
Adjustments for:		
Depreciation and amortisation expense	**1,047**	890
Impairments of property, plant and equipment and intangible assets	**210**	61
Net finance costs	**118**	238
Share of operating loss of equity accounted investments	**1**	5
Other	**(215)**	(51)
Changes in assets and liabilities:		
Trade and other receivables	**(630)**	(122)
Inventories	**29**	(52)
Trade and other payables	**74**	25
Provisions and other assets and liabilities	**(144)**	(97)
Cash generated from operations	**1,980**	460
Dividends received	**8**	10
Net interest paid	**(104)**	(119)
Income taxes paid (including royalty taxes)	**(496)**	(245)
Net operating cash flows	**1,388**	106
Investing activities		
Purchases of property, plant and equipment	**(556)**	(498)
Exploration expenditure	**(131)**	(14)
Investment in subsidiaries, operations and joint operations, net of cash	**-**	(482)
Net investment and funding of equity accounted investments	**(2)**	(1)
Other investing	**-**	(26)
Proceeds from sale of assets	**146**	41
Net investing cash flows	**(543)**	(980)
Financing activities		
Lease payments	**(18)**	(19)
Repayments of long-term borrowing to BHP Group	**-**	(3,994)
Net other financing with BHP Group	**(633)**	4,869
Currency valuation change	**23**	(90)
Net financing cash flows	**(628)**	766
Net increase/(decrease) in cash and cash equivalents	**217**	(108)
Cash and cash equivalents, net of overdrafts at the beginning of the period	**776**	325
Foreign currency exchange rate changes on cash and cash equivalents	**(1)**	-
Cash and cash equivalents, net of overdrafts at the end of the period	**992**	217

The accompanying notes form part of these half year financial statements.

BHP Petroleum Assets

Combined statement of changes in equity for the half year ended 31 December 2021

	Share capital [1] US$M	Retained earnings US$M	Foreign currency translation reserve US$M	Total equity US$M
Balance as at 1 July 2021	**15,234**	**(15,610)**	**3,488**	**3,112**
Total comprehensive income/(loss)	**-**	**583**	**1**	**584**
Deemed contributions from BHP Group	**-**	**4,278**	**-**	**4,278**
Balance as at 31 December 2021	**15,234**	**(10,749)**	**3,489**	**7,974**
Balance as at 1 July 2020	15,234	(13,997)	3,487	4,724
Total comprehensive loss	-	(387)	-	(387)
Deemed distributions to BHP Group	-	(1,252)	-	(1,252)
Balance as at 31 December 2020	15,234	(15,636)	3,487	3,085

[1] Number of shares outstanding of BHP Petroleum International Pty Ltd (Parent of BHP Petroleum) for the reporting periods ended 31 December 2021 and 2020 were 18,876,136,568.

The accompanying notes form part of these half year financial statements.

1. Organisation and summary of significant accounting policies

Organisation

BHP Petroleum Assets are a subset of certain entities wholly owned by BHP Group Limited. The subset of entities primarily represents BHP Group Limited's interests in its petroleum businesses, whose principal activities are the exploration, development and production of oil and gas. These petroleum businesses comprise of oil and gas assets located in the United States (US), Gulf of Mexico, Australia, Trinidad and Tobago, Algeria and Mexico and appraisal and exploration options in Trinidad and Tobago, central and western US Gulf of Mexico, eastern Canada, Egypt and Barbados. The purpose of these non-statutory half year combined financial statements is to provide general purpose historical financial information of the BHP Petroleum Assets for inclusion in listing documents to be issued by Woodside Petroleum Limited, which has entered into a share sale agreement to combine with BHP Petroleum Assets (Proposed Transaction).

These half year combined financial statements include financial information that is limited to the legal entities carved out (BHP Petroleum) from BHP Group Limited (BHP Group), in connection with the Proposed Transaction. BHP Petroleum consists of BHP Petroleum International Pty Ltd and the entities it controls, except for the following entities:

- BHP BK Limited
- BHP Billiton Petroleum Great Britain Limited
- BHP Mineral Resources Inc.
- BHP Copper Inc. and its subsidiaries
- BHP Capital Inc.

BHP Petroleum International Pty Ltd, the Parent of BHP Petroleum, is a proprietary limited company domiciled in Western Australia, Australia. The registered office of BHP Petroleum International Pty Ltd is 125 St Georges Terrace, Perth WA 6000.

Ultimate group company

BHP Group Limited, a company incorporated in the state of Victoria, Australia, is the ultimate Parent company. Copies of the ultimate Parent company's financial statements are available from BHP Centre, 171 Collins Street, Melbourne Victoria 3000, Australia.

Basis of presentation

The combined financial statements for the half year ended 31 December 2021 are unaudited and have been prepared in accordance with IAS 34 'Interim Financial Reporting' as issued by the International Accounting Standards Board (IASB). The half year combined financial statements represent a 'condensed set of financial statements' and do not include all of the information required for a full annual report and are to be read in conjunction with the most recent audited fiscal year BHP Petroleum financial statements.

The same accounting policies and methods of computation are followed in the interim financial statements as compared with the most recent audited annual financial statements.

All amounts are expressed in US dollars unless otherwise stated. BHP Petroleum's presentation currency and the functional currency of the majority of its operations is US dollars as this is the principal currency of the economic environment in which it operates. Amounts in this half year financial report have, unless otherwise indicated, been rounded to the nearest million dollars.

At 31 December 2021 BHP Petroleum had net amounts payable to BHP Group of US$1,700 million. Under the terms of the Share Sale Agreement, between BHP Group and Woodside Petroleum Limited, intra-group funding arrangements are required to be repaid or otherwise eliminated. BHP Petroleum expects to settle intercompany balances with BHP Group either as a capital injection or loan forgiveness neither of which will involve an outflow of cash in order to satisfy the terms of the Share Sale Agreement. BHP Petroleum has made an assessment of its ability to continue as a going concern over the period to 4 March 2023 (the going concern period) and believes that it has sufficient financial resources to meet its obligations as they fall due throughout the going concern period. As such, the financial statements continue to be prepared on a going concern basis.

2. Revenue

The following table provides a summary of BHP Petroleum's revenue by geographic location:

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Australia	**761**	501
North America	**1,025**	454
United Kingdom	**-**	15
Rest of Europe	**113**	79
Japan	**270**	167
South Korea	**38**	16
China	**35**	38
Other Asia	**763**	265
Rest of World	**193**	67
Total revenue	**3,198**	1,602

The following table provides a summary of BHP Petroleum's revenue by asset:

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Australia Production Unit [(1)]	**225**	123
Bass Strait	**775**	478
North West Shelf	**865**	402
Atlantis	**517**	212
Shenzi	**326**	137
Mad Dog	**157**	88
Trinidad and Tobago	**206**	68
Algeria	**108**	75
Third-party products	**6**	3
Other	**13**	16
Total revenue	**3,198**	1,602

[(1)] Australia Production Unit includes Macedon and Pyrenees.

The following table provides a summary of BHP Petroleum's revenue by product:

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Crude oil	**1,656**	772
Gas	**1,334**	712
Natural gas liquids	**183**	93
Other	**25**	25
Total revenue	**3,198**	1,602

Revenue consists of revenue from contracts with customers of US$3,187 million (31 December 2020: US$1,583 million) and other revenue of US$11 million (31 December 2020: US$19 million).

3. Expenses and other income

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Employee benefits expense:		
Wages, salaries and redundancies	**147**	183
Employee share awards	**11**	17
Pension and other post-retirement obligations	**30**	32
Less employee benefits expense classified as exploration and evaluation expenditure	**(31)**	(48)
Changes in inventories of finished goods	**12**	(9)
Raw materials and consumables used	**57**	45
Freight and transportation	**62**	40
External services	**274**	302
Third-party commodity purchases	**7**	3
Net foreign exchange losses	**(5)**	32
Government royalties paid and payable	**119**	44
Exploration and evaluation and expenditure incurred and expensed in the period	**112**	181
Depreciation and amortisation expense	**1,047**	890
Fair value change on derivatives	**32**	1
Net impairments:		
Property, plant and equipment (1)	**210**	57
Intangible assets	**-**	4
Other expenses (2)	**(323)**	42
Total expenses	**1,761**	1,816
Dividend income	**1**	5
Gain from sell-down of Scarborough interest (3)	**104**	-
Other income (4)	**67**	15
Total other income	**172**	20

(1) At 31 December 2021, the overall recoverable amount of the Ruby operations in offshore Trinidad and Tobago was determined to be US$107 million, resulting in an impairment charge of US$210 million against property, plant and equipment. The valuation of Ruby is most sensitive to changes in reserves, with the impairment driven by revisions to estimated reserves resulting from technical analysis of well drilling results and performance following project completion in December 2021. Recoverable amount for the impairment assessment was determined based on Ruby's value in use.

(2) Half year ended 31 December 2021 includes US$355 million LNG underlift valuation movement.

(3) Gain attributable to Final Investment Decision (FID) of the Scarborough project pursuant to the 2016 divestment of BHP Petroleum's 25 per cent Scarborough Joint Venture interest to Woodside.

(4) Other income includes boat charter, tax barrel income, tariff revenue, income from licensing agreements and sublease income.

4. Income tax

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Total taxation expense/(income) comprises:		
Current tax expense	**822**	228
Deferred tax expense/(benefit)	**85**	(278)
	907	(50)

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Factors affecting income tax expense/(income) for the half year		
Income tax expense differs to the standard rate of corporation tax as follows:		
Profit/(loss) before taxation	**1,490**	(437)
Tax expense/(benefit) at Australian prima facie tax rate of 30 per cent	**447**	(131)
Non-tax effected operating losses and capital gains	**188**	156
Tax effect of loss from equity accounted investments, related impairments and expenses	**-**	1
Amounts under provided in prior periods	**55**	65
Recognition of previously unrecognised tax assets	**1**	-
Foreign exchange adjustments	**33**	(87)
Impact of tax rates applicable outside of Australia	**(3)**	5
Other [1]	**149**	(43)
Income tax expense/(income)	**870**	(34)
Royalty-related taxation (net of income tax benefit)	**37**	(16)
Total taxation expense/(income)	**907**	(50)

[1] Includes US$163 million tax expense related to the taxable gain on the disposal of Hamilton Oil Company Inc's interest in BHP Billiton Petroleum Great Britain Limited, refer to Note 12 'Related party transactions'

5. Trade and other receivables

	31 Dec 2021 US$M	30 June 2021 US$M
Trade receivables	**319**	358
Joint operations partner receivables [1]	**764**	384
Value-added tax (VAT) and other tax related receivables	**288**	262
Other receivables	**60**	61
Total trade and other receivables	**1,431**	1,065
Comprising:		
Current	**1,230**	908
Non-current	**201**	157

(1) Joint operations partner receivables include production underlift positions and receivables for joint operations cash float arrangements.

6. Trade and other payables

	31 Dec 2021 US$M	30 June 2021 US$M
Trade payables external	**638**	641
Other payables	**314**	278
Total trade and other payables	**952**	919

7. Closure and rehabilitation provisions

A reconciliation of the changes in the closure and rehabilitation provisions is shown in the following table:

	31 Dec 2021 US$M	30 June 2021 US$M
At the beginning of the period	**3,957**	3,595
Capitalised amounts for operating sites:		
Change in estimate	**13**	131
Exchange translation	**(71)**	162
Adjustments charged/(credited) to the income statement for closed sites:		
Change in estimate	**(1)**	17
Exchange translation	**(6)**	10
Other adjustments to the provision:		
Amortisation of discounting impacting net finance costs	**58**	94
Acquisition of subsidiaries and operations	**-**	179
Divestment and demerger of subsidiaries and operations	**-**	(81)
Expenditure on closure and rehabilitation activities	**(43)**	(152)
Exchange variations impacting foreign currency translation reserve	**(3)**	2
At the end of the period	**3,904**	3,957
Comprising:		
Current	**144**	141
Non-current	**3,760**	3,816
Operating sites	**3,580**	3,623
Closed sites	**324**	334

BHP Petroleum is required to rehabilitate sites and associated facilities at the end of, or in some cases, during the course of production, to a condition acceptable to the relevant authorities, at the time rehabilitation occurs, and in accordance with BHP Group's environmental performance requirements as set out within the BHP Group Charter. The requirements of the relevant authorities vary by jurisdiction and are often non-prescriptive.

The key components of closure and rehabilitation activities are:

- the removal of certain infrastructure associated with an operation
- the return of disturbed areas to a safe, stable, productive and self-sustaining condition, consistent with agreed end use.

The recognition and measurement of closure and rehabilitation provisions requires the use of significant estimates and assumptions, including, but not limited to:

- the extent (due to legal or constructive obligations) of potential activities required for the removal of infrastructure and rehabilitation activities
- costs associated with future rehabilitation activities
- applicable discount rates
- the timing of cash flows and ultimate closure of operations.

Many rehabilitation activities are expected to occur a number of years in the future and the precise requirements that will have to be met when the rehabilitation occurs is currently uncertain. Decommissioning technologies and costs are constantly changing, as are political, environmental, safety and public expectations.

Management determines the best estimate of future closure and rehabilitation cash flows by weighting a range of possible scenarios, including only partial removal of offshore infrastructure where BHP Petroleum believes it will be able demonstrate to the relevant regulators, that such an approach will result in better environmental, safety and asset integrity outcomes.

While the closure and rehabilitation provisions reflect management's best estimates based on current knowledge and information, further studies and detailed analysis of the closure activities for individual assets will be performed as the assets near the end of their operational life and/or detailed closure plans are required to be submitted to, and agreed with, relevant regulatory authorities. Such studies and analysis can impact the estimated costs of closure activities. Estimates can also be impacted by the emergence of new restoration techniques, changes in regulatory requirements for rehabilitation, risks relating to climate change and the transition to a low carbon economy and experience at other operations. These uncertainties may result in future actual expenditure differing from the amounts currently provided for in the balance sheet.

8. Other provisions

The disclosure below excludes closure and rehabilitation provisions (refer to Note 7 'Closure and rehabilitation provisions'), employee benefits, restructuring and post-retirement employee benefits provisions (refer to Note 10 'Employee benefits, restructuring and post-retirement employee benefits provisions').

A reconciliation of changes in other provisions for other liabilities is shown in the following table:

	31 Dec 2021 US$M	30 June 2021 US$M
At the beginning of the period	**233**	168
Charge/(credit) for the year:		
Disposals	**-**	(1)
Underlying	**9**	122
Discounting	**-**	1
Exchange variations	**(3)**	6
Released during the period	**(14)**	(7)
Utilisation	**(10)**	(57)
Transfers and other movements	**(2)**	1
At the end of the period	**213**	233
Comprising:		
Current	**131**	137
Non-current	**82**	96

9. Fair value measurement

All financial assets and financial liabilities are initially recognised at the fair value of consideration paid or received, net of transaction costs as appropriate and subsequently carried at fair value or amortised cost. The financial assets and liabilities are presented by class in the tables below at their carrying values, which generally approximate to fair values.

The carrying amount of financial assets and liabilities measured at fair value is principally calculated based on inputs other than quoted prices that are observable for these financial assets or liabilities, either directly (i.e. as unquoted prices) or indirectly (i.e. derived from prices). Where no price information is available from a quoted market source, alternative market mechanisms or recent comparable transactions, fair value is estimated based on BHP Petroleum's views on relevant future prices, net of valuation allowances to accommodate liquidity, modelling and other risks implicit in such estimates.

The valuation techniques used by BHP Petroleum to measure fair value include the use of internally developed methodologies and models that result in management's best estimate of fair value. Inputs used in the valuation include, but are not limited to, future commodity prices, market discount rates and consideration of risks specific to the asset or liability being fair valued.

If, at inception of a contract, the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognised in the income statement but deferred on the balance sheet and is commonly known as 'day-one gain or loss'. This deferred gain or loss is recognised in the income statement over the life of the contract until substantially all the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognised in the income statement. Changes in valuation subsequent to the initial valuation at inception of a contract are recognised immediately in the income statement.

For financial assets and liabilities carried at fair value, BHP Petroleum uses the following to categorise the method used based on the lowest level input that is significant to the fair value measurement as a whole:

Level 1 – Based on quoted process (unadjusted) in active markets for identical financial assets and liabilities

Level 2 – Based on inputs other than quoted prices included within Level 1 that are observable for the financial asset or liability

Level 3 – Based on inputs not observable in the market using appropriate valuation models, including discounted cash flow modelling

For financial instruments that are carried at fair value on a recurring basis, BHP Petroleum determines whether transfers have occurred between levels in the hierarchy by reassessing categorisation at the end of each reporting period. There were no transfers between categories during the period.

	IFRS 13 Fair value hierarchy Level	**IFRS 9 Classification**	**31 Dec 2021 US$M**	30 June 2021 US$M
Cash and cash equivalents		Amortised cost	**992**	776
Trade and other receivables		Amortised cost	**1,431**	1,065
Receivables from BHP Group		Amortised cost	**10,852**	5,526
Other financial assets [(1)]	3	Fair value through profit or loss	**37**	51
Total financial assets			**13,312**	7,418
Trade and other payables		Amortised cost	**952**	919
Payables to BHP Group		Amortised cost	**12,552**	12,348
Other financial liabilities	3	Fair value through profit or loss	**60**	9
Interest bearing liabilities		Amortised cost	**257**	269
Total financial liabilities			**13,821**	13,545

[(1)] Includes US$ nil (30 June 2021: US$46 million) contingent consideration receivable and US$37 million (30 June 2021: US$5 million) derivatives embedded in physical commodity purchase contract.

The carrying value of Other financial assets and Other financial liabilities includes an embedded derivative resulting from a physical commodity (gas) purchase and sale contract in Trinidad and Tobago. The carrying value of the embedded derivative at 31 December 2021 was a net liability of US$23 million (30 June 2021: net liability of US$4 million).

The following table presents the impact of activity for financial instruments classified as Level 3 in the fair value hierarchy:

	31 Dec 2021 US$M	30 June 2021 US$M
Fair value at the beginning of the period	**42**	72
Losses recognised in income statement	**(10)**	(10)
Settlements	**(55)**	(20)
Net fair value at the end of the period	**(23)**	42

10. Employee benefits, restructuring and post-retirement employee benefits provisions

	31 Dec 2021 US$M	30 June 2021 US$M
Employee benefits provisions [(1)]	**78**	147
Restructuring provisions [(2)]	**7**	31
Post-retirement employee benefits provisions	**259**	248
Total provisions	**344**	426
Comprising:		
Current	**85**	178
Non-current	**259**	248

[(1)] The expenditure associated with total employee benefits will occur in a pattern consistent with when employees choose to exercise their entitlement to benefits.
[(2)] Total restructuring provisions include provisions for terminations.

	Employee benefits [(1)] US$M	Restructuring [(2)] US$M	Post-retirement employee benefits US$M	Total US$M
As at 30 June 2021	**147**	**31**	**248**	**426**
Charge/(credit) for the year:				
Underlying	**47**	**1**	**12**	**60**
Discounting	**-**	**-**	**6**	**6**
Net interest expense	**-**	**-**	**(2)**	**(2)**
Exchange variations	**(1)**	**-**	**-**	**(1)**
Released during the year	**(1)**	**-**	**(10)**	**(11)**
Utilisation	**(114)**	**(25)**	**5**	**(134)**
As at 31 December 2021	**78**	**7**	**259**	**344**

[(1)] The expenditure associated with total employee benefits will occur in a pattern consistent with when employees choose to exercise their entitlement to benefits.
[(2)] Total restructuring provisions include provisions for terminations.

BHP Petroleum contributed US$18 million during the half year ended 31 December 2021 (31 December 2020: US$19 million) to defined contribution plans and multi-employer defined contribution plans.

11. Investments in associates

Ownership interest for BHP Petroleum's investments in associates, which are operated in the US, are listed in the table below:

Associates	Principal activity	Reporting date	Ownership interest % [(1)]
Caesar Oil Pipeline Company LLC	Hydrocarbons transportation	31 December	25
Cleopatra Gas Gathering Company LLC	Hydrocarbons transportation	31 December	22
Marine Well Containment Company LLC	Oil spill services	31 December	10

(1) Reflects BHP Petroleum's ownership interest as at 31 December 2021 and 31 December 2020.

The following table summarises the financial information relating to each of BHP Petroleum's significant equity accounted investments:

	Half year ended 31 Dec 2021 US$'000	Half year ended 31 Dec 2020 US$'000
Share of profit/(loss) of equity accounted investments:		
Caesar Oil Pipeline Company LLC	**3,694**	2,325
Cleopatra Gas Gathering Company LLC	**1,511**	559
Marine Well Containment Company LLC	**(6,523)**	(7,412)
Share of loss of equity accounted investments	**(1,318)**	(4,528)
Dividends received	**6,909**	4,993
Contributions	**(1,500)**	(1,260)

12. Related party transactions

Transactions with equity accounted investments

The following transactions took place during the half year with equity accounted investments:

	Half year ended 31 Dec 2021 US$M	Half year ended 31 Dec 2020 US$M
Purchases of goods/services	**10**	7
Dividends received	**7**	5

Outstanding balances with related parties

	Equity Accounted Investments		BHP Group Entities	
	31 Dec 2021 US$M	30 June 2021 US$M	**31 Dec 2021 US$M**	30 June 2021 US$M
Amounts receivable from BHP Group	**-**	-	**10,852**	5,526
Trade amounts owed to related parties	**1**	2	**-**	-
Amounts payable to BHP Group	**-**	-	**12,552**	12,348

BHP Petroleum has financing arrangements with BHP Group for short-term cash management. As at 31 December 2021 current amounts receivable from BHP Group related to these financing arrangements was US$10,852 million (30 June 2021: US$5,526 million). These amounts are included in Receivables from BHP Group on the balance sheet. During the half year ended 31 December 2021, BHP Petroleum entities Hamilton Oil Company Inc. and BHP Petroleum Investments (Great Britain) Pty Ltd sold their respective shareholdings in BHP Billiton Petroleum Great Britain Limited and BHP BK Limited for US$4.3 billion to BHP Group companies outside the Proposed Transaction boundary. As the disposed entities are outside of the Proposed Transaction boundary and excluded from the BHP Petroleum Assets financial statements, the proceeds from the sale were recorded as an equity transaction between BHP Petroleum and BHP Group with no gain or loss recognised in earnings. As at 31 December 2021 the amounts receivable from BHP Group related to the divestment was US$4.3 billion, included in Receivables from BHP Group on the balance sheet. For tax purposes, the sale generated a taxable gain which did not result in current taxes payable as it was offset by a reduction of BHP Petroleum's net operating loss deferred tax asset. Tax expense of US$163 million related to the taxable gain has been recognized in BHP Petroleum's financial statements.

BHP Petroleum also entered into long-term debt agreements with BHP Group to finance its projects. As at 31 December 2021 and 30 June 2021, the outstanding balance relating to these agreements was US$10,347 million. This balance was recorded as a non-current liability in Payables to BHP Group at 30 June 2021 and was reclassed to a current liability in Payables to BHP Group as it became current at 31 December 2021. As at 31 December 2021 current amounts payable to BHP Group related to financing arrangements outside the long-term debt agreements were US$2,205 million (30 June 2021: US$2,001 million). These amounts are included in Payables to BHP Group on the balance sheet.

Interest expense related to the long-term debt, recorded in Finance expense in the income statement, for the half year ended 31 December 2021 was US$101 million (31 December 2020: US$148 million). The long-term debt agreements with BHP Group are entered at 3-month USD LIBOR plus margin. The margin ranges between 1.3 per cent and 1.8 per cent. The long-term debt agreements have a maturity date between November 2022 and December 2022.

There are no expected credit losses related to balances from related parties at 31 December 2021 and 30 June 2021.

BHP Petroleum has entered into various performance and corporate guarantees with certain BHP Group entities in the normal course of business. As at 31 December 2021, BHP Petroleum had outstanding guarantees as follows:

Guarantees provided by BHP Petroleum:

- corporate guarantee given to financial institutions that manage future trades in order to hedge oil and gas production with maximum exposure of US$1 million

Guarantees received by BHP Petroleum:

- corporate guarantee received for regulatory requirements for drilling in the amount of US$24 million
- corporate guarantee received for exploration licenses in the amount of US$249 million
- corporate guarantee received for Outer Continental Shelf Right of Way Grant Bond in the amount of US$3 million
- corporate guarantee received for plugging and abandonment of wells in the amount of US$12 million

The likelihood of these performance and corporate guarantees being called upon is considered remote.

13. Subsequent events

No matters or circumstances have arisen since the end of the half year, 31 December 2021, that have significantly affected, or may significantly affect, the operations, results of operations or state of affairs of BHP Petroleum in subsequent accounting periods.

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Review Report of Independent Auditors to the Shareholder and the Board of Directors of BHP Petroleum International Pty Ltd

We have reviewed the condensed combined financial information of BHP Petroleum Assets, which comprise the combined statement of financial position as of 31 December 2021, and the related combined statements of profit or loss and comprehensive income or loss, statement of cash flows and statement of changes in equity for the half year ended 31 December 2021.

Management's Responsibility for the Financial Information

Management is responsible for the preparation and fair presentation of the condensed combined financial information in conformity with IAS 34 *Interim Financial* Reporting as issued by the International Accounting Standards Board (IASB) ; this includes the design, implementation and maintenance of internal control sufficient to provide a reasonable basis for the preparation and fair presentation of interim financial information in conformity with IAS 34 *Interim Financial Reporting*.

Auditor's Responsibility

Our responsibility is to conduct our review in accordance with auditing standards generally accepted in the United States of America applicable to reviews of interim financial information. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial information. Accordingly, we do not express such an opinion.

Conclusion

Based on our review, we are not aware of any material modifications that should be made to the condensed combined financial information referred to above for it to be in conformity with IAS 34 *Interim Financial Reporting* as issued by IASB.

Report on combined statement of financial position as of 30 June 2021

We have previously audited, in accordance with auditing standards generally accepted in the United States of America, the combined statement of financial position of BHP Petroleum Assets as of 30 June 2021, and the related combined statements of profit or loss and comprehensive income or loss, statement of cash flows and statement of changes in equity for the year then ended; and we expressed an unmodified audit opinion on those audited combined financial statements in our report dated 17 December 2021. In our opinion, the accompanying combined statement of financial position of BHP Petroleum Assets as of 30 June 2021, is consistent, in all material respects, with the combined statement of financial position from which it has been derived.

Ernst & Young

Ernst and Young
Melbourne, Australia
4 March 2022

Confidential

BHP Petroleum Assets

Combined Financial Statements as of and
for the Years Ended 30 June 2021, 2020 and 2019
Report of Independent Auditors

BHP Petroleum Assets

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Financial Statements

Report of Independent Auditors

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Report of Independent Auditors to the Shareholder and the Board of Directors of BHP Petroleum International Pty Ltd

We have audited the accompanying combined financial statements of BHP Petroleum Assets, which comprise the combined statement of financial position as of 30 June 2021 and 2020, and the related combined statements of profit or loss and other comprehensive income, cash flows and changes in equity for the years then ended, and the related notes to the combined financial statements (collectively referred to as the "financial statements").

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board; this includes the design, implementation and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free of material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the combined financial position of BHP Petroleum Assets at June 30, 2020 and 2021, and the combined results of their operations and their cash flows for the years then ended in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on comparative information

We have not audited, reviewed or compiled the comparative combined information presented herein as of and for the year ended June 30, 2019, and, accordingly, we express no opinion on it.

Ernst & Young

Ernst & Young
Melbourne, Australia
17 December 2021

BHP Petroleum Assets

Combined statement of profit or loss and comprehensive income or loss for the years ended 30 June 2021, 2020 and 2019

	Notes	**2021 US$M**	2020 US$M	*Unaudited* 2019 US$M
Continuing operations				
Revenue	3	**3,909**	3,997	5,867
Other income	4	**130**	57	32
Expenses excluding net finance costs	4	**(3,799)**	(3,390)	(3,510)
Loss from equity accounted investments	21	**(6)**	(4)	(2)
Profit from operations		**234**	660	2,387
Finance expense	9, 17	**(464)**	(660)	(1,001)
Finance income		**56**	304	364
Net finance costs		**(408)**	(356)	(637)
Profit/(loss) before taxation		**(174)**	304	1,750
Income tax expense		**(211)**	(400)	(925)
Royalty - related taxation (net of income tax benefit)		**24**	(82)	(164)
Total taxation expense	5	**(187)**	(482)	(1,089)
Profit/(loss) after taxation from Continuing operations		**(361)**	(178)	661
Discontinued operations				
Loss after taxation from Discontinued operations	24	**-**	-	(335)
Profit/(loss) after taxation from Continuing and Discontinued operations		**(361)**	(178)	326
Attributable to non-controlling interests		**-**	-	7
Attributable to BHP shareholders		**(361)**	(178)	319
Other comprehensive income or loss				
Items that may be reclassified subsequently to the income statement:				
Exchange fluctuations on transactions of foreign operations taken to equity		**-**	1	1
Total items that may be reclassified subsequently to the income statement		**-**	1	1
Items that will not be reclassified to the income statement:				
Re-measurement gain/(loss) on pension & medical schemes	18	**1**	(14)	(10)
Tax recognised within other comprehensive income		**-**	3	2
Total items that will not be reclassified to the income statement		**1**	(11)	(8)
Total other comprehensive income/(loss)		**1**	(10)	(7)
Total comprehensive income/(loss)		**(360)**	(188)	319
Attributable to non-controlling interests		**-**	-	7
Attributable to BHP shareholders		**(360)**	(188)	312

The accompanying notes form part of these financial statements.

BHP Petroleum Assets

Combined statement of financial position as at 30 June 2021, 2020 and 2019

	Notes	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
ASSETS				
Current assets				
Cash and cash equivalents	9, 17	**776**	325	1,398
Trade and other receivables	6	**908**	673	835
Receivables from BHP Group	22	**5,526**	12,424	15,871
Other financial assets	17	**-**	7	3
Inventories	7	**307**	250	251
Current tax assets	5	**130**	210	6
Other		**9**	34	23
Total current assets		**7,656**	13,923	18,387
Non-current assets				
Trade and other receivables	6	**157**	112	38
Other financial assets	17	**52**	86	67
Property, plant and equipment	8	**11,854**	11,787	10,628
Intangible assets	11	**78**	110	104
Net investments and funding of equity accounted investments	21	**253**	245	239
Deferred tax assets	5	**2,182**	2,041	2,040
Other		**3**	5	1
Total non-current assets		**14,579**	14,386	13,117
Total assets		**22,235**	28,309	31,504
LIABILITIES				
Current liabilities				
Trade and other payables	13	**919**	771	929
Payables to BHP Group	17, 22	**2,001**	6,533	6,520
Interest bearing liabilities	9	**35**	61	17
Other financial liabilities		**9**	6	1
Current tax payable	5	**280**	292	465
Closure and rehabilitation provisions	14	**141**	162	205
Other provisions	15,18	**315**	274	277
Deferred income		**14**	25	21
Total current liabilities		**3,714**	8,124	8,435
Non-current liabilities				
Non-current tax payable	5	**14**	-	-
Payables to BHP Group	17, 22	**10,347**	10,347	14,340
Interest bearing liabilities	9	**234**	322	-
Closure and rehabilitation provisions	14	**3,816**	3,433	2,095
Deferred tax liabilities	5	**610**	1,028	1,244
Other provisions	15, 18	**344**	276	368
Deferred income		**44**	55	85
Total non-current liabilities		**15,409**	15,461	18,132
Total liabilities		**19,123**	23,585	26,567
Net assets		**3,112**	4,724	4,937
EQUITY		**3,112**	4,724	4,937

The accompanying notes form part of these financial statements.

BHP Petroleum Assets

Combined statement of cash flows for the years ended 30 June 2021, 2020 and 2019

	Notes	**2021 US$M**	2020 US$M	*Unaudited* 2019 US$M
Operating activities				
Profit/(loss) before taxation		**(174)**	304	1,750
Adjustments for:				
Depreciation and amortisation expense		**1,840**	1,457	1,560
Impairments of property, plant and equipment and intangible assets		**127**	11	21
Net finance costs		**408**	356	637
Share of operating loss of equity accounted investments		**6**	4	2
Other		**(187)**	(141)	(223)
Changes in assets and liabilities:				
Trade and other receivables		**(298)**	253	142
Inventories		**(42)**	(1)	(1)
Trade and other payables		**52**	(166)	17
Provisions and other assets and liabilities		**11**	(152)	(212)
Cash generated from operations		**1,743**	1,925	3,693
Dividends received		**25**	20	17
Net interest paid		**(257)**	(395)	(553)
Income taxes paid (including royalty taxes)		**(451)**	(965)	(810)
Net operating cash flows from Continuing operations		**1,060**	585	2,347
Net operating cash flows from Discontinued operations	24	**-**	-	474
Net operating cash flows		**1,060**	585	2,821
Investing activities				
Purchases of property, plant and equipment		**(994)**	(909)	(645)
Exploration expenditure		**(26)**	(169)	(297)
Investment in subsidiaries, operations and joint operations, net of cash		**(480)**	-	-
Net investment and funding of equity accounted investments		**(25)**	(22)	(6)
Other investing		**(34)**	(11)	(4)
Proceeds from sale of assets		**39**	78	8
Net investing cash flows from Continuing operations		**(1,520)**	(1,033)	(944)
Net investing cash flows from Discontinued operations	24	**-**	-	(443)
Net investing cash flows		**(1,520)**	(1,033)	(1,387)
Financing activities				
Lease payments		**(38)**	(39)	-
Repayments of long-term borrowing to BHP Group		**(3,993)**	(3,000)	-
Net other financing with BHP Group		**4,941**	2,432	(12,544)
Proceeds from issuance of shares to BHP Group		**-**	-	2,000
Net financing cash flows from Continuing operations		**910**	(607)	(10,544)
Net financing cash flows from Discontinued operations	24	**-**	-	(13)
Net financing cash flows		**910**	(607)	(10,557)
Net increase/(decrease) in cash and cash equivalents from Continuing operations		**450**	(1,055)	(9,141)
Net increase in cash and cash equivalents from Discontinued operations	24	**-**	-	18
Proceeds from divestment of Onshore US, net of its cash		**-**	-	10,427
Cash and cash equivalents, net of overdrafts at the beginning of the financial year		**325**	1,381	77
Foreign currency exchange rate changes on cash and cash equivalents		**1**	(1)	-
Cash and cash equivalents, net of overdrafts at the end of the financial year	9	**776**	325	1,381

The accompanying notes form part of these financial statements.

BHP Petroleum Assets

Combined statement of changes in equity for the years ended 30 June 2021, 2020 and 2019

	Share capital [(1)] US$M	Retained earnings US$M	Foreign currency translation reserve US$M	Equity attributable to Parent US$M	Non-controlling interests US$M	Total equity US$M
Balance as at 1 July 2020	**18,676**	**(13,998)**	**46**	**4,724**	**-**	**4,724**
Total comprehensive loss	**-**	**(360)**	**-**	**(360)**	**-**	**(360)**
Deemed distributions to BHP Group	**-**	**(1,252)**	**-**	**(1,252)**	**-**	**(1,252)**
Balance as at 30 June 2021	**18,676**	**(15,610)**	**46**	**3,112**	**-**	**3,112**
Balance as at 1 July 2019	18,676	(13,784)	45	4,937	-	4,937
Total comprehensive income/(loss)	-	(189)	1	(188)	-	(188)
Deemed distributions to BHP Group	-	(25)	-	(25)	-	(25)
Balance as at 30 June 2020	18,676	(13,998)	46	4,724	-	4,724
Unaudited						
Balance as at 1 July 2018	16,676	(14,095)	44	2,625	168	2,793
Total comprehensive income	-	311	1	312	7	319
Issuance of shares to BHP Group	2,000	-	-	2,000	-	2,000
Change in ownership in subsidiaries	-	-	-	-	(175)	(175)
Balance as at 30 June 2019	18,676	(13,784)	45	4,937	-	4,937

[(1)] Number of shares outstanding of BHP Petroleum International Pty Ltd (Parent of BHP Petroleum) for the reporting periods ended 30 June 2021, 2020, 2019 were 18,876,136,568. On May 29, 2019, 2,890,800,028 ordinary shares were issued to BHP Group Limited for US$2,000 million in consideration.

The accompanying notes form part of these financial statements.

1. Organisation and summary of significant accounting policies

Organisation

BHP Petroleum Assets are a subset of entities wholly owned by BHP Group Limited. The subset of entities primarily represents BHP Group Limited's interests in its petroleum businesses, whose principal activities are the exploration, development and production of oil and gas. These petroleum businesses comprise of oil and gas assets located in the United States (US) Gulf of Mexico, Australia, Trinidad and Tobago, Algeria and Mexico and appraisal and exploration options in Trinidad and Tobago, central and western US Gulf of Mexico, eastern Canada and Barbados. The purpose of these non-statutory combined financial statements is to provide general purpose historical financial information of the BHP Petroleum Assets for inclusion in listing documents to be issued by Woodside Petroleum Limited, which has entered into a share sale agreement to combine with BHP Petroleum Assets (Proposed Transaction).

These combined financial statements include financial information that is limited to the legal entities carved out (BHP Petroleum) from BHP Group Limited, in connection with the Proposed Transaction. BHP Petroleum consists of BHP Petroleum International Pty Ltd and the entities it controls, except for the following entities:

- BHP BK Limited
- BHP Billiton Petroleum Great Britain Limited
- BHP Mineral Resources Inc.
- BHP Copper Inc. and its subsidiaries
- BHP Capital Inc.

A list of the subsidiaries included within BHP Petroleum's combined financial statements is included in Note 23 'Significant entities of BHP Petroleum'.

BHP Petroleum International Pty Ltd, the Parent of BHP Petroleum, is a proprietary limited company domiciled in Western Australia, Australia. The registered office of BHP Petroleum International Pty Ltd is 125 St Georges Terrace, Perth WA 6000.

Ultimate group company

BHP Group Limited, a company incorporated in the state of Victoria, Australia, is the ultimate Parent company. Copies of the ultimate Parent company's financial statements are available from BHP Centre, 171 Collins Street, Melbourne Victoria 3000, Australia.

Basis of presentation

These combined financial statements present the results of BHP Petroleum, as at and for the years ended 30 June 2021, 2020 and 2019 (the reporting periods) and comprise of:

- the combined statement of profit or loss and other comprehensive income for the years then ended;
- the combined statement of financial position as at the years ended;
- the combined statement of cash flows for the years then ended;
- the combined statement of changes in equity for the years then ended and
- notes comprising a summary of significant accounting policies and other explanatory information.

The financial information of BHP Petroleum has been extracted on a "carve-out" basis from the accounting records of BHP Group for the purposes of presenting the combined financial position, combined results of operations and combined cash flows of BHP Petroleum. The combined financial statements reflect assets, liabilities, revenues and expenses directly attributable to BHP Petroleum identified above. BHP Petroleum has adopted the same accounting policies as BHP Group, unless otherwise stated.

The combined financial statements as at and for the reporting periods:

- are a combined general purpose financial report
- have been prepared in accordance with the requirements of the Australian Corporations Act 2001 and UK Companies Act 2006
- were prepared in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB)
- are prepared on a going concern basis
- measure items on the basis of historical cost principles, except for the following items:
  - derivative financial instruments and certain other financial assets and liabilities, which are carried at fair value
- include significant accounting policies in the notes to the financial statements that summarise the recognition and measurement basis used and are relevant to an understanding of the combined financial statements
- apply a presentation currency of US dollars, consistent with the predominant functional currency of BHP Petroleum's operations. However, some subsidiaries and joint arrangements have functional currencies other than US dollars
- round amounts presented to the nearest million dollars, unless otherwise stated
- adopt all new and amended standards and interpretations under IFRS issued by the relevant bodies (listed above) (refer to Note 25 'New and amended accounting standards and interpretations'), that are mandatory for application in periods beginning on 1 July 2019. Those new and amended standards and interpretations did not require restatement of prior period financial information
- early adopt amendments to IFRS 9 'Financial Instruments' (IFRS 9); IAS 39 'Financial Instruments: Recognition and Measurement' (IAS 39); IFRS 7 'Financial Instruments: Disclosures' (IFRS 7) and IFRS 16 'Leases' (IFRS 16) in relation to Interest Rate Benchmark Reform (refer to Note 25 'New and amended accounting standards and interpretations')
- have not early adopted any other standards and interpretations that have been issued or amended but are not yet effective

The accounting policies are consistently applied by all entities included in BHP Petroleum.

Principles of combination

In preparing the combined financial statements, the effects of all intragroup balances and transactions have been eliminated in accordance with the consolidation requirements of IFRS 10 'Consolidated Financial Statements'.

The combined financial statements of BHP Petroleum include the combination of entities controlled by BHP Petroleum International Pty Ltd, except for certain controlled entities as identified above, which are excluded on the basis that they are outside the Proposed Transaction.

Control exists where BHP Petroleum:

- is exposed to, or has rights to, variable returns from its involvement with the entity.
- has the ability to affect those returns through its power to direct the activities of the entity.
- has the ability to approve the operating and capital budget of an entity and the ability to appoint key management personnel, which are decisions that demonstrate that BHP Petroleum has the existing rights to direct the relevant activities of an entity.

Joint arrangements

BHP Petroleum undertakes a number of business activities through joint arrangements, which exist when two or more parties have joint control. All of BHP Petroleum's joint arrangements are classified as joint operations. A joint operation is an arrangement in which BHP Petroleum shares joint control, primarily via contractual arrangements with other parties. In a joint operation, BHP Petroleum has rights to the assets and obligations for the liabilities relating to the arrangement. This includes situations where the parties benefit from the joint activity through a share of the output, rather than by receiving a share of the results of trading. In relation to BHP Petroleum's interest in a joint operation, BHP Petroleum recognises: its assets and liabilities, including its share of any assets and liabilities held or incurred jointly; revenue from the sale of its share of the output and its share of any revenue generated from the sale of the output by the joint operation; and its expenses including its share of expenses incurred jointly. All such amounts are measured in accordance with the terms of the arrangement, which is usually in proportion to BHP Petroleum's interest in the joint operation.

Associates

BHP Petroleum accounts for investments in associates using the equity accounting method. An entity is considered an associate where we are deemed to have significant influence but not control or joint control.

Significant influence is presumed to exist where BHP Petroleum:

- has over 20 per cent but less than 50 per cent of the voting rights of an entity, unless it can be clearly demonstrated that this is not the case or
- holds less than 20 per cent of the voting rights of an entity; however, has the power to participate in the financial and operating policy decisions affecting the entity.

Foreign currencies

Transactions related to BHP Petroleum's worldwide operations are conducted in a number of foreign currencies. The majority of the subsidiaries, joint arrangements and associates within each of the operations have assessed US dollars as the functional currency, however, some subsidiaries and joint arrangements have functional currencies other than US dollars.

Transactions and monetary items denominated in foreign currencies are translated into US dollars as follows:

Foreign currency item	**Applicable exchange rate**
Transactions	Date of underlying transaction
Monetary assets and liabilities	Period-end rate

Foreign exchange gains and losses resulting from translation are recognised in the income statement, except for foreign exchange gains or losses on foreign currency provisions for site closure and rehabilitation costs (which are capitalised in property, plant and equipment for operating sites).

On combination, the assets, liabilities, income and expenses of non-US dollar denominated functional currency entities are translated into US dollars using the following applicable exchange rates:

Foreign currency amount	Applicable exchange rate
Income and expenses	Date of underlying transaction
Assets and liabilities	Period-end rate
Equity	Historical rate
Reserves	Historical rate

Foreign exchange differences resulting from translation are initially recognised in the foreign currency translation reserve and subsequently transferred to the income statement on disposal of a foreign operation.

Significant accounting policies, judgements and estimates

BHP Petroleum has identified a number of accounting policies under which significant judgements, estimates and assumptions are made. All judgements, estimates and assumptions are based on the most current facts and circumstances and are reassessed on an ongoing basis. Actual results in future reporting periods may differ for these estimates under different assumptions and conditions. Significant judgements and key estimates and assumptions made in applying these accounting policies are embedded within Note 5 'Income Tax', Note 8 'Property, plant and equipment', Note 11 'Intangible assets', Note 12 'Impairment of non-current assets' and Note 14 'Closure and rehabilitation provisions'.

Reserve estimates

Reserves are estimates of the amount of product that can be demonstrated to be able to be economically and legally extracted from BHP Petroleum's properties. In order to estimate reserves, assumptions are required about a range of technical and economic factors, including quantities, qualities, production techniques, recovery efficiency, production and transport costs, commodity supply and demand, commodity prices and exchange rates.

Estimating the quantity and/or quality of reserves requires the size, shape and depth or oil and gas reservoirs to be determined by analysing geological data, such as drilling samples and geophysical survey interpretations. Economic assumptions used to estimate reserves change from period-to-period as additional technical and operational data is generated. This process may require complex and difficult geological judgements to interpret the data.

Reserve impact on financial reporting

Estimates of reserves may change from period-to-period as the economic assumptions used to estimate reserves change and additional geological data is generated during the course of operations. Changes in reserves may affect BHP Petroleum's financial results and financial position in a number of ways, including:

- asset carrying values may be affected due to changes in estimated future production levels
- depreciation, depletion and amortisation charged in the income statement may change where such charges are determined on the units of production basis, or where the useful economic lives of assets change

- closure and rehabilitation provisions may change where changes in estimated reserves affect expectations about the timing or cost of these activities

- the carrying amount of deferred tax assets may change due to changes in estimates of the likely recovery of the tax benefits

Impact of Coronavirus Disease 2019 (COVID-19) Pandemic

BHP Petroleum continues to actively monitor the impact of the COVID-19 pandemic, including the impact on economic activity and financial reporting. During FY2021, BHP Petroleum experienced lower commodity prices and market demand driven by travel restrictions and lockdowns. As the pandemic continues to progress and evolve, it is difficult to predict the full extent and duration of resulting operational and economic impacts for BHP Petroleum, which are expected to impact a number of reporting periods. The ongoing uncertainty has also been considered in BHP Petroleum's assessment of the appropriateness of applying the going concern basis of preparation of the financial statements. BHP Petroleum has made an assessment of its ability to continue as a going concern over the period to 30 November 2022 (the going concern period) and believes that it has sufficient financial resources to meet its obligations as they fall due throughout the going concern period. As such, the financial statements continue to be prepared on a going concern basis.

2. First time adoption of IFRS

Management has given due consideration to the requirements of IFRS 1 'First-time Adoption of International Financial Reporting Standards' in preparing these combined financial statements. The combined financial statements of BHP Petroleum are the first combined financial statements presented by BHP Petroleum. Entities included within the combined financial statements, for all periods presented, have applied the recognition and measurement requirements of IFRS, in accordance with BHP Group accounting policies. As such, the preparation of these combined financial statements has not required the transition to IFRS recognition and measurement requirements.

For this purpose, the date of BHP Petroleum's first presentation of IFRS financial statements is determined to be 1 July 2018, being the beginning of the earliest period for which BHP Petroleum presents full comparative information in these combined financial statements. BHP Petroleum has measured its assets and liabilities at the carrying amounts that are included in BHP Group's consolidated financial statements, based on BHP Group's date of transition to IFRSs. With due regard to BHP Group's accounting policies and the requirements of IFRS 1, management has concluded that no adjustments were required to comply with IFRS as issued by the IASB.

BHP Petroleum Assets

Notes to the Financial Statements

3. Revenue

The following table provides a summary of BHP Petroleum's revenue by geographic location:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Australia	**1,133**	1,080	1,340
North America	**1,285**	1,108	1,903
United Kingdom	**28**	40	77
Rest of Europe	**161**	149	260
Japan	**407**	567	887
South Korea	**16**	-	28
China	**74**	73	95
Other Asia	**638**	808	1,016
Rest of World	**167**	172	261
Total revenue	**3,909**	3,997	5,867

The following table provides a summary of BHP Petroleum's revenue by asset:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Australia Production Unit [1]	**327**	361	507
Bass Strait	**1,066**	1,102	1,237
North West Shelf	**893**	1,076	1,657
Atlantis	**560**	561	979
Shenzi	**417**	277	540
Mad Dog	**231**	216	319
Trinidad and Tobago	**204**	191	287
Algeria	**164**	159	258
Third-party products	**12**	5	10
Other	**35**	49	73
Total revenue	**3,909**	3,997	5,867

(1) Australia Production Unit includes Macedon, Pyrenees and Minerva (divested in December 2019).

The following table provides a summary of BHP Petroleum's revenue by product:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Crude oil	**2,013**	2,033	3,173
Gas	**1,659**	1,754	2,399
Natural gas liquids	**212**	198	252
Other	**25**	12	43
Total revenue	**3,909**	3,997	5,867

Revenue consists of revenue from contracts with customers of US$3,859 million (2020: US$3,952 million, 2019: US$5,817 million) and other revenue of US$50 million (2020: US$45 million, 2019: US$50million).

Recognition and measurement

BHP Petroleum generates revenue primarily from the production and sale of crude oil, natural gas and natural gas liquids (NGLs). Revenue is recognised when or as control of the promised goods or services passes to the customer. In most instances, control passes when the goods are delivered to a destination specified by the customer, typically on board the customer's appointed vessel or at another contractually agreed delivery point such as an outlet to storage facilities. Where applicable, revenue from the provision of services is recognised over time but does not represent a significant proportion of total revenue and is aggregated with the respective asset and product revenue for disclosure purposes. The amount of revenue recognised reflects the consideration to which BHP Petroleum expects to be entitled in exchange for the goods or services. As at 30 June 2021, 2020 and 2019, no significant estimates are required to determine revenue from contracts with customers.

Major customers

BHP Petroleum has two major customers which account for 18 per cent and 10 per cent of external revenue (2020: one customer, 13 per cent, 2019: one customer, 15 per cent). BHP Petroleum does not believe the loss of either of these customers would have a material adverse effect on BHP Petroleum because the markets in which BHP Petroleum sells its production volumes are significant liquid markets with alternative customers readily available for its production volumes.

Contract balances and asset recognition

Where BHP Petroleum's sales are provisionally priced, the final price is generally known within the month of sale due to the typical pricing terms of BHP Petroleum's contracts with customers. The period between provisional pricing and final invoicing is typically less than 30 days.

BHP Petroleum applies the practical expedient to not adjust the expected consideration for the effects of the time value of money if the period between the delivery and when the customer pays for the promised good or service is one year or less.

Performance obligations

For commodity sales contracts, each metric unit is a separate performance obligation. Where BHP Petroleum has contracts with unfulfilled performance obligations at period-end, it is required to disclose the transaction price allocated to these performance obligations. BHP Petroleum applies the practical expedient to not disclose this information for contracts with an expected duration of one year or less. Most of BHP Petroleum's long-term contracts are priced on variable terms, based on quoted index prices near the time of delivery and at times include fixed pricing components. Long-term contracts that include fixed pricing components, such as premiums and other charges, do not represent a significant portion of the total price. Any estimate of the future transaction price would exclude estimated amounts of variable consideration. The amount of future consideration from fixed pricing components has not been disclosed, as it is not considered to be relevant or useful information.

BHP Petroleum Assets

Notes to the Financial Statements

4. Expenses and other income

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Employee benefits expense:			
Wages, salaries and redundancies	**381**	388	416
Employee share awards	**36**	39	45
Pension and other post-retirement obligations	**42**	37	68
Less employee benefits expense classified as exploration and evaluation expenditure	**(93)**	(50)	(70)
Changes in inventories of finished goods	**(13)**	22	26
Raw materials and consumables used	**90**	97	121
Freight and transportation	**112**	117	150
External services	**620**	505	387
Third-party commodity purchases	**11**	6	11
Net foreign exchange losses	**17**	14	(5)
Government royalties paid and payable	**137**	191	223
Exploration and evaluation and expenditure incurred and expensed in the period	**296**	395	388
Depreciation and amortisation expense	**1,840**	1,457	1,560
Fair value change on derivatives	**58**	29	1
Net impairments:			
Property, plant and equipment [1]	**108**	11	7
Intangible assets	**19**	-	14
Other expenses	**138**	132	168
Total expenses	**3,799**	3,390	3,510
Dividend income	**14**	8	-
Gain on sale of subsidiaries and operations [2]	**56**	-	-
Other income [3]	**60**	49	32
Total other income	**130**	57	32

(1) Refer to Note 12 'Impairment of non-current assets'.

(2) Relates to the divestiture of our interest in Neptune, Gulf of Mexico. Refer to Note 8 'Property, plant and equipment' and Note 14 'Closure and rehabilitation provisions'.

(3) Other income is generally income earned from transactions outside the course of BHP Petroleum's ordinary activities and may include boat charter and tariff revenue.

Recognition and measurement

Income is recognised when it is probable that the economic benefits associated with a transaction will flow to BHP Petroleum and can be reliably measured. Dividends are recognised upon declaration.

5. Income tax

	2021 US$M	2020 US$M	Unaudited 2019 US$M
Total taxation expense comprises:			
Current tax expense	**743**	696	1,147
Deferred tax benefit	**(556)**	(214)	(58)
	187	482	1,089

	2021 US$M	2020 US$M	Unaudited 2019 US$M
Factors affecting income tax expense for the year			
Income tax expense differs to the standard rate of corporation tax as follows:			
(Loss)/profit before taxation	**(174)**	304	1,750
Tax expense/(benefit) at Australian prima facie tax rate of 30 per cent	**(52)**	91	525
Non-tax effected operating losses and capital gains	**272**	209	289
Tax effect of loss from equity accounted investments, related impairments and expenses	**2**	1	1
Investment and development allowance	**-**	-	(1)
Tax rate changes	**-**	(1)	12
Amounts under/(over) provided in prior years	**46**	50	(6)
Recognition of previously unrecognised tax assets	**-**	(23)	-
Foreign exchange adjustments	**(61)**	(21)	35
Impact of tax rates applicable outside of Australia	**77**	99	60
Other	**(73)**	(5)	10
Income tax expense	**211**	400	925
Royalty-related taxation (net of income tax benefit)	**(24)**	82	164
Total taxation expense	**187**	482	1,089

Income tax recognised in other comprehensive income is as follows:

	2021 US$M	2020 US$M	Unaudited 2019 US$M
Income tax effect of:			
Items that may be reclassified to the income statement:			
Income tax (charge)/credit relating to items that may be reclassified subsequently to the income statement	-	-	-
Items that will not be reclassified to the income statement:			
Remeasurement gains/(losses) on pension and medical schemes	-	3	2
Others	-	-	-
Income tax (charge)/credit relating to items that will not be reclassified to the income statement	-	3	2
Total income tax (charge)/credit relating to components of other comprehensive income (1)	-	3	2

(1) Included within total income tax relating to components of other comprehensive income is US$ nil relating to deferred taxes and US$ nil relating to current taxes (2020: US$3 million and US$ nil; 2019: US$2 million and US$ nil).

Recognition and measurement

Income taxes have been prepared on a separate return basis for the net income/(loss) from operations of BHP Petroleum based upon the estimated applicable income tax rates for the jurisdictions in which BHP Petroleum is taxable, while also reflecting that, in historically filed returns, BHP Petroleum in Australia is part of the income tax consolidated group return parented by BHP Group Limited.

Current tax payables and receivables are the amounts of tax payable or refundable on the basis of hypothetical, current year separate returns, adjusted to reflect actual historical transactions undertaken in relation to the income tax consolidated group return parented by BHP Group Limited.

As such, the benefit of tax losses generated by certain entities has not been recognised in BHP Petroleum's Combined statement of profit or loss and comprehensive income or loss as these losses were transferred to BHP Group Limited in the year in which they were generated. These losses, amounting to US$83 million (2020:US$143 million, 2019:US$205 million) would have been utilised by BHP Petroleum, and recognised as a credit in profit and loss, had BHP Petroleum operated as a hypothetical tax consolidated group.

Deferred taxes are provided on temporary differences and on any carry forward losses or unused credits that could be claimed on hypothetical returns and the recoverability of recognised and unrecognised deferred taxes is assessed on the basis of projected separate-return results.

Taxation on the profit/(loss) for the year comprises of current and deferred tax. Taxation is recognised in the income statement except to the extent that it relates to items recognised directly in equity or other comprehensive income, in which case the tax effect is also recognised in equity or other comprehensive income.

Current tax

Current tax is the expected tax on the taxable income for the year, using tax rates and laws enacted or substantively enacted at the reporting date and any adjustments to tax payable in respect of previous years.

Deferred tax

Deferred tax is provided in full, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

Deferred tax is not recognised for temporary differences relating to:

- initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit
- investment in subsidiaries, associates and jointly controlled entities where BHP Petroleum is able to control the timing of the reversal of the temporary difference and it is probable that they will not reverse in the foreseeable future.

Deferred tax is measured at the tax rates that are expected to be applied when the asset is realised or the liability is settled, based on the laws that have been enacted or substantively enacted at the reporting date.

Current and deferred tax assets and liabilities are offset when BHP Petroleum has a legally enforceable right to offset and when the tax balances are related to taxes levied by the same tax authority and BHP Petroleum intends to settle on a net basis or realise the asset and settle the liability simultaneously.

Royalty-related taxation

Royalties and resource rent taxes are treated as taxation arrangements (impacting income tax expense/(benefit)) when they are imposed under government authority and the amount payable is calculated by reference to revenue derived (net of any allowable deductions) after adjustment for temporary differences. Obligations arising from royalty arrangements that do not satisfy these criteria are recognised as current liabilities and included in expenses.

Uncertain tax and royalty matters

BHP Petroleum operates across many tax jurisdictions. Application of tax law can be complex and requires judgement to assess risk and estimate outcomes. The evaluation of tax risks considers both amended assessments received and potential sources of challenge from tax authorities. The status of proceedings for these matters will impact the ability to determine the potential exposure and in some cases, it may not be possible to determine a range of possible outcomes or a reliable estimate of the potential exposure.

BHP Petroleum has unresolved tax and royalty matters for which the timing of resolution and potential economic outflow are uncertain. Tax and royalty matters with uncertain outcomes arise in the normal course of business and occur due to changes in tax law, changes in interpretation of tax law, periodic challenges and disagreements with tax authorities and legal proceedings.

Tax and royalty obligations assessed as having probable future economic outflows capable of reliable measurement are provided for in the balance sheet. Matters with possible economic outflow and/or presently incapable of being measured reliably are contingent liabilities and disclosed in Note 16 'Contingent liabilities'.

Key judgements and estimates

Income tax classification

Judgements: BHP Petroleum's accounting policy for taxation, including royalty-related taxation, requires management's judgement as to the types of arrangements considered to be a tax on income in contrast to an operating cost.

Deferred tax

Judgements: Judgement is required to determine the amount of deferred tax assets that are recognised based on the likely timing and the level of future taxable profits.

Estimates: BHP Petroleum assesses the recoverability of recognised and unrecognised deferred taxes, on a consistent basis. Estimates and assumptions relating to projected earnings and cash flows as applied in BHP Petroleum's impairment process are used for operating assets.

Uncertain tax matters

Judgements: Management applies judgements about the application of income tax legislation and its interaction with income tax accounting principles. These judgements are subject to risk and uncertainty, hence there is a possibility that changes in circumstances will alter expectations, which may impact the amount of tax assets and tax liabilities, including deferred tax, recognised on the balance sheet and the amount of other tax losses and temporary differences not yet recognised.

Where the final tax outcomes are different from the amounts that were initially recorded, these differences impact the current and deferred tax provisions in the period in which the determination is made.

Measurement of uncertain tax and royalty matters considers a range of possible outcomes, including assessments received from tax authorities. Where management is of the view that potential liabilities have a low probability of crystallising, or it is not possible to quantify them reliably, they are disclosed as contingent liabilities (refer to Note 16 'Contingent liabilities').

The movement for the year in BHP Petroleum's net deferred tax positions is as follows:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Net deferred tax (liability/asset)			
At the beginning of the financial year	**1,013**	796	736
Income tax credit recorded in the income statement	**556**	214	58
Income tax credit recorded directly in equity	**3**	3	2
At the end of the financial year	**1,572**	1,013	796

BHP Petroleum Assets

Notes to the Financial Statements

The composition of BHP Petroleum's net deferred tax assets and liabilities recognised in the balance sheet and the deferred tax expense charged/(credited) to the income statement is as follows:

	Deferred tax assets			Deferred tax liabilities			Charged/(credited) to the income statement		
	2021 US$M	2020 US$M	*Unaudited* 2019 US$M	2021 US$M	2020 US$M	*Unaudited* 2019 US$M	**2021 US$M**	2020 US$M	*Unaudited* 2019 US$M
Type of temporary difference									
Depreciation	**(1,024)**	(1,054)	(629)	**(66)**	(105)	(119)	**(69)**	411	(11)
Exploration expenditure	**32**	37	43	**-**	-	-	**5**	6	7
Employee benefits	**63**	63	59	**-**	-	1	**-**	-	1
Closure and rehabilitation	**1,036**	967	604	**(18)**	-	-	**(51)**	(363)	(78)
Resource rent tax	**292**	363	431	**(526)**	(922)	(1,123)	**(322)**	(133)	(168)
Other provisions	**65**	55	49	**-**	-	-	**(10)**	(6)	(20)
Deferred income	**7**	8	9	**-**	-	-	**1**	1	(6)
Foreign exchange gains and losses	**3**	1	1	**-**	-	-	**(2)**	-	(1)
Tax losses	**1,667**	1,541	1,421	**-**	-	-	**(126)**	(120)	156
Lease liability	**55**	79	-	**-**	-	-	**24**	(79)	-
Other	**(14)**	(19)	52	**-**	(1)	(3)	**(6)**	69	62
Total	**2,182**	2,041	2,040	**(610)**	(1,028)	(1,244)	**(556)**	(214)	(58)

The amount of deferred tax assets dependent on future taxable profits not arising from the reversal of existing deferred tax liabilities and which relate to tax jurisdictions where the taxable entity has suffered a loss in the current or preceding year, was US$ nil at 30 June 2021 (2020: US$ nil, 2019: US$1,250 million). For operating assets, BHP Petroleum assesses the recoverability of these deferred tax assets using estimates and assumptions relating to projected earnings and cash flows as applied in BHP Petroleum impairment process for associated operations.

BHP Petroleum Assets

Notes to the Financial Statements

The composition of BHP Petroleum's unrecognised deferred tax assets and liabilities is as follows:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Unrecognised deferred tax assets			
Tax losses and tax credits (1)	**1,078**	1,219	1,145
Deductible temporary differences relating to PRRT (2)	**2,402**	2,079	2,197
Petroleum rights (3)	**566**	552	545
Other deductible temporary differences (4)	**419**	315	398
Total unrecognised deferred tax assets	**4,465**	4,165	4,285
Unrecognised deferred tax liabilities			
Future taxable temporary differences relating to unrecognised deferred tax asset for PRRT (2)	**720**	624	659
Total unrecognised deferred tax liabilities	**720**	624	659

(1) At 30 June 2021, BHP Petroleum had income and capital tax losses with a tax benefit of US$768 million (2020: US$890 million, 2019: US$823 million) and tax credits of US$310 million (2020: US$329 million, 2019: US$321 million), which are not recognised as deferred tax assets, because it is not probable that future taxable profits or capital gains will be available against which BHP Petroleum can utilise the benefits.

(2) BHP Group had unrecognised deferred tax assets relating to Australian Petroleum Resource Rent Tax (PRRT). Recognition of a deferred tax asset for PRRT depends on benefits expected to be obtained from the deduction against PRRT liabilities. As PRRT payments are deductible for income tax purposes, to the extent these PRRT deferred tax assets are recognised this would give rise to a corresponding deferred tax liability for income tax (presented as the future taxable temporary differences relating to the unrecognised PRRT deferred tax assets).

(3) BHP Petroleum had deductible temporary differences relating to mineral rights for which deferred tax assets had not been recognised because it is not probable that future capital.

(4) BHP Petroleum had other deductible temporary differences for which deferred tax assets had not been recognised because it is not probable that future tax profits will be available against which BHP Petroleum can utilise the benefits.
The deductible temporary differences do not expire under current tax legislation.

Year of Expiry	**2021 US$M**	2020 US$M	*Unaudited* 2019 US$M
Income tax losses			
Not later than one year	**12**	474	359
Later than one year and not later than two years	**3**	239	442
Later than two years and not later than five years	**46**	2,475	2,713
Later than five years and not later than ten years	**1,339**	600	455
Later than ten years and not later than twenty years	**1,787**	2,373	2,267
Unlimited	**824**	757	653
	4,011	6,918	6,889
Capital tax losses			
Not later than one year	**-**	-	-
Later than two years and not later than five years	**-**	-	-
Unlimited	**1**	-	-
Total capital tax losses	**1**	-	-
Gross amount of tax losses not recognised	**4,012**	6,918	6,889
Tax effect of total losses not recognised	**768**	892	823

BHP Petroleum Assets

Notes to the Financial Statements

6. Trade and other receivables

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Trade receivables	**358**	185	392
Joint operations partner receivables [1]	**384**	257	240
Value-added tax (VAT) and other tax related receivables	**262**	282	238
Other receivables	**61**	61	3
Total trade and other receivables	**1,065**	785	873
Comprising:			
Current	**908**	673	835
Non-current	**157**	112	38

(1) Joint operations partner receivables include production underlift positions and receivables for joint operations cash float arrangements.

Recognition and measurement

Trade receivables are recognised initially at their transaction price or, for those receivables containing a significant financing component, at fair value. Trade receivables are subsequently measured at amortised cost using the effective interest method, less an allowance for impairment, except for provisionally priced receivables (where applicable) which are subsequently measured at fair value through the income statement under IFRS 9 'Financial Instruments'.

The collectability of trade receivables is assessed on an ongoing basis. At the reporting date, specific allowances are made for any expected credit losses based on a review of all outstanding amounts at reporting period-end. Individual receivables are written off when management deems them unrecoverable. The net carrying amount of trade and other receivables approximates their fair values.

Credit risk

Trade receivables generally have terms of less than 30 days. BHP Petroleum has no material concentration of credit risk with any single counterparty and are not dominantly exposed to any individual industry.

Credit risk can arise from the non-performance by counterparties of their contractual financial obligations towards BHP Petroleum. To manage credit risk, BHP Petroleum maintains procedures covering the application for credit approvals, granting and renewal of counterparty limits, proactive monitoring of exposures against these limits and requirements triggering secured payment terms. As part of these processes, the credit exposures with all counterparties are regularly monitored and assessed on a timely basis. The credit quality of customers is reviewed and the solvency of each debtor and their ability to pay the receivable is considered in assessing receivables for impairment.

The ten largest customers represented 66 per cent (2020: 59 per cent, 2019: 51 per cent) of total credit risk exposures managed by BHP Petroleum.

Receivables are deemed to be past due or impaired in accordance with our terms and conditions. These terms and conditions are determined on a case-by-case basis with reference to the customer's credit quality, payment performance and prevailing market conditions. As at 30 June 2021, 30 June 2020 and 30 June 2019 no trade receivables were past due.

The assessment of recoverability of trade receivables at 30 June 2021 has considered the impacts of COVID-19 and no material recoverability issues have been identified. As COVID-19 continues to impact key markets in Australia, United States, Europe and Asia, BHP Petroleum continues to perform enhanced credit monitoring of commercial counterparties.

At 30 June 2021 and 2020, provisions for expected credit losses were not significant.

7. Inventories

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M	**Definitions**
Raw materials and consumables	**271**	226	206	Spares, consumables and other supplies yet to be utilised in the production process or in the rendering of services.
Finished goods	**36**	24	45	Commodities ready for sale and not requiring further processing.
Total inventories	**307**	250	251	

Recognition and measurement

Finished goods inventories primarily represent crude oil in storage. Regardless of the type of inventory and its stage in the production process, inventories are valued at the lower of cost and net realisable value. Cost is determined primarily on the basis of average costs. For processed inventories, cost is derived on an absorption costing basis. Cost comprises costs of purchasing raw materials and costs of production, including attributable manufacturing overheads taking into consideration normal operating capacity. Inventory quantities are derived through flow rate or tank volume measurement and the composition is derived via sample analysis.

8. Property, plant and equipment

	Land and buildings US$M	Plant and equipment US$M	Other mineral assets US$M	Assets under construction US$M	Exploration and evaluation US$M	Total US$M
Net book value - 30 June 2021						
At the beginning of the financial year	**257**	**8,268**	**133**	**2,040**	**1,089**	**11,787**
Additions [1]	**1**	**294**	**-**	**1,133**	**7**	**1,435**
Acquisitions of subsidiaries & operations [2]	**-**	**151**	**491**	**-**	**-**	**642**
Depreciation for the year	**(27)**	**(1,719)**	**(62)**	**-**	**-**	**(1,808)**
Impairments for the year [3]	**(40)**	**(2)**	**-**	**-**	**(66)**	**(108)**
Divestment and demerger of subsidiaries and operations [4]	**-**	**(14)**	**-**	**(2)**	**-**	**(16)**
Transfers and other movements	**-**	**675**	**-**	**(753)**	**-**	**(78)**
At the end of the financial year [5]	**191**	**7,653**	**562**	**2,418**	**1,030**	**11,854**
- Cost	**463**	**29,358**	**1,090**	**2,418**	**1,086**	**34,415**
- Accumulated depreciation and impairments	**(272)**	**(21,705)**	**(528)**	**-**	**(56)**	**(22,561)**
Net book value - 30 June 2020						
At the beginning of the financial year	101	8,103	144	1,240	1,040	10,628
Impact of adopting IFRS 16 [7]	233	128	-	-	-	361
Additions [1]	4	1,246	-	1,008	120	2,378
Depreciation for the year	(32)	(1,368)	(19)	-	-	(1,419)
Impairments for the year [3]	-	(11)	-	-	-	(11)
Disposals [6]	-	(8)	-	-	(65)	(73)
Transfers and other movements	(49)	178	8	(208)	(6)	(77)
At the end of the financial year [5]	257	8,268	133	2,040	1,089	11,787
- Cost	462	28,965	600	2,040	1,089	33,156
- Accumulated depreciation and impairments	(205)	(20,697)	(467)	-	-	(21,369)
Unaudited						
Net book value - 30 June 2019						
At the beginning of the financial year	151	8,985	167	903	790	10,996
Additions [1]	-	292	-	978	296	1,566
Depreciation for the year	(50)	(1,510)	(23)	-	-	(1,583)
Impairments for the year [3]	-	-	-	-	(7)	(7)
Disposals [6]	-	(15)	-	-	-	(15)
Transfers and other movements	-	351	-	(641)	(39)	(329)
At the end of the financial year [5]	101	8,103	144	1,240	1,040	10,628
- Cost	274	27,791	592	1,240	1,044	30,941
- Accumulated depreciation and impairments	(173)	(19,688)	(448)	-	(4)	(20,313)

(1) Includes change in estimates, impact of discount rate change and net foreign exchange gains/(losses) related to the closure and rehabilitation provisions for operating sites. Refer to Note 14 'Closure and rehabilitation provisions'.
(2) Relates to the acquisition of an additional 28 per cent working interest in Shenzi. Refer to Note 20 'Interest in joint operations'.
(3) Refer to Note 12 'Impairment of non-current assets' for information on impairments.

BHP Petroleum Assets

Notes to the Financial Statements

(4) Relates to the divestment of our 35 per cent interest in the Gulf of Mexico Neptune field, which closed in May 2021. The transfer resulted in a book gain on disposal of US$56 million. The book gain was largely the result of transferring the Neptune closure obligation liability to the acquirer.
(5) Includes the carrying value of BHP Petroleum's right-of-use assets relating to land and buildings and plant and equipment of US$131 million (2020: US$263 million, 2019: US$ nil). Refer to Note 9 'Interest bearing liabilities' for the movement of the right-of-use assets.
(6) US$65 million relates to the divestment of BHP Petroleum's 50 per cent interest in the Murphy Oil operated Samurai field in the Gulf of Mexico; which closed in November 2019.
(7) Refer to Note 25 'New and amended accounting standards and interpretations'.

Recognition and measurement

Property, plant and equipment is recorded at cost less accumulated depreciation and impairment charges. Cost is the fair value of consideration given to acquire the asset at the time of its acquisition or construction and includes the direct costs of bringing the asset to the location and the condition necessary for operation and the estimated future costs of closure and rehabilitation of the facility.

Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses and adjusted for any remeasurement of the lease liabilities.

Exploration and evaluation

Exploration costs are incurred to discover petroleum resources. Evaluation costs are incurred to assess the technical feasibility and commercial viability of resources found.

Exploration and evaluation expenditure is charged to the income statement as incurred, except in the following circumstances in which case the expenditure may be capitalised:

- the exploration and evaluation activity is within an area of interest for which it is expected that the expenditure will be recouped by future exploitation or sale, or
- the exploration and evaluation activity has not reached a stage that permits a reasonable assessment of the existence of commercially recoverable reserves.

A regular review of each area of interest is undertaken to determine the appropriateness of continuing to carry forward costs in relation to that area. Capitalised costs are only carried forward to the extent that they are expected to be recovered through the successful exploitation of the area of interest or alternatively by its sale. To the extent that capitalised expenditure is no longer expected to be recovered, it is charged to the income statement.

Key judgements and estimates

Judgements: Exploration and evaluation expenditure results in certain items of expenditure being capitalised for an area of interest where a judgement is made that it is likely to be recoverable by future exploitation or sale, or where the activities are judged not to have reached a stage that permits a reasonable assessment of the existence of reserves.

Estimates: Management makes certain estimates and assumptions as to future events and circumstances, in particular when making a quantitative assessment of whether an economically viable extraction operation can be established. These estimates and assumptions may change as new information becomes available. If, after having capitalised the expenditure under the policy, new information suggests that recovery of the expenditure is unlikely, the relevant capitalised amount is charged to the income statement.

Development expenditure

When proven reserves are determined and development is sanctioned, capitalised exploration and evaluation expenditure is reclassified as assets under construction within property, plant and equipment. All subsequent development expenditure is capitalised and classified as assets under construction, provided commercial viability conditions continue to be satisfied.

BHP Petroleum may use borrowed funds to finance the acquisition and development of assets and operations. Finance costs are expensed as incurred, except where they relate to the financing of construction or development of qualifying assets. Borrowing costs directly attributable to acquiring or constructing a qualifying asset are capitalised during the development phase. Development expenditure is net of proceeds from the saleable material extracted during the development phase. On completion of development, all assets included in assets under construction are reclassified as either plant and equipment or other mineral assets and depreciation commences.

Key judgements and estimates

Judgements: Development activities commence after project sanctioning by the appropriate level of management. Judgement is applied by management in determining when a project is economically viable.

*Estimate*s: In determining whether a project is economically viable, management is required to make certain estimates and assumptions as to future events and circumstances, including reserve estimates, existence of an accessible market and forecast prices and cash flows. Estimates and assumptions may change as new information becomes available. If, after having commenced the development activity, new information suggests that a development asset is impaired, the appropriate amount is charged to the income statement.

Depreciation

Depreciation of assets, other than land, assets under construction and capitalised exploration and evaluation that are not depreciated, is calculated using either the straight-line (SL) method or units of production (UoP) method, net of residual values, over the estimated useful lives of specific assets. The depreciation method and rates applied to specific assets reflect the pattern in which the asset's benefits are expected to be used by BHP Petroleum. The proved reserves for petroleum assets are used to determine UoP depreciation unless doing so results in depreciation charges that do not reflect the asset's useful life. Where this occurs, alternative approaches to determining reserves are applied, such as using management's expectations of future oil and gas prices rather than yearly average prices, to provide a phasing of periodic depreciation charges that better reflects the asset's expected useful life.

Where assets are dedicated to a petroleum lease, the useful lives below are subject to the lesser of the asset category's useful life and the life of the petroleum lease, unless those assets are readily transferable to another lease.

Key judgements and estimates

The determination of useful lives, residual values and depreciation methods involves estimates and assumptions and is reviewed annually. Any changes to useful lives or any other estimates or assumptions may affect prospective depreciation rates and asset carrying values. The table below summarises the principal depreciation methods and rates applied to major asset categories by BHP Petroleum.

Category	Buildings	Plant and equipment	Petroleum interests	Capitalised exploration, evaluation and development expenditure
Typical depreciation methodology	SL	UoP	UoP	UoP

Depreciation rate	15 – 50 years	Based on the rate of depletion of reserves	Based on the rate of depletion of reserves	Based on the rate of depletion of reserves

Commitments

BHP Petroleum's commitments for capital expenditure were US$754 million at 30 June 2021 (2020: US$971 million, 2019: US$1,201 million). BHP Petroleum's commitments related to leases are included in Note 10 'Leases'.

9. Interest bearing liabilities

	Current			**Non-current**		
			Unaudited			*Unaudited*
	2021 US$M	2020 US$M	2019 US$M	**2021 US$M**	2020 US$M	2019 US$M
Lease liabilities	**35**	61	-	**234**	322	-
Bank overdrafts	**-**	-	17	**-**	-	-
Total interest bearing liabilities	**35**	61	17	**234**	322	-

Further information on BHP Petroleum's leases is provided in Note 10 'Leases'.

Cash is disclosed in the cash flow statement net of bank overdrafts and interest bearing liabilities at call.

			Unaudited
	2021 US$M	2020 US$M	2019 US$M
Total cash and cash equivalents	**776**	325	1,398
Bank overdrafts	**-**	-	(17)
Total cash and cash equivalents, net of overdrafts	**776**	325	1,381

BHP Petroleum Assets

Notes to the Financial Statements

10. Leases

BHP Petroleum applied IFRS 16 'Leases' from 1 July 2019. Details on the transition to IFRS 16 are included in Note 25 'New and amended accounting standards and interpretations'.

Movements in BHP Petroleum's lease liabilities during the year are as follows:

	2021 US$M	2020 US$M
At the beginning of the financial year	**383**	-
IFRS 16 transition [1]	**-**	438
Additions	**2**	13
Lease payments	**(45)**	(46)
Foreign exchange movement	**-**	1
Amortisation of discounting	**7**	8
Derecognition due to lease modification	**(62)**	-
Transfers and other movements	**(16)**	(31)
At the end of the financial year	**269**	383
Comprising:		
Current liabilities	**35**	61
Non-current liabilities	**234**	322

[1] Refer to Note 25 'New and amended accounting standards and interpretations'.

A significant proportion by value of BHP Petroleum's lease contracts relate to building leases, drill rig and equipment leases. These lease contracts contain a wide variety of different terms and considerations including extension and termination options and variable lease payments. BHP Petroleum's lease obligations are included in the interest-bearing liabilities.

The maturity profile of lease liabilities based on the undiscounted contractual amounts is as follows:

	2021 US$M	2020 US$M
Due for payment:		
In one year or less or on demand	**41**	70
In more than one year but not more than two years	**37**	70
In more than two years but not more than five years	**91**	130
In more than five years [1]	**133**	156
Total	**302**	**426**
Less amount representing interest	**33**	43
Present value of net minimum lease payments	**269**	**383**

[1] Includes US$9 million (2020: US$35 million) due for payment in more than ten years.

At 30 June 2021, commitments for leases not yet commenced based on undiscounted contractual amounts were US$36 million (2020: US$14 million). At 30 June 2021, commitments relating to short-term leases were US$8 million (2020: US$2 million).

BHP Petroleum Assets

Notes to the Financial Statements

BHP Petroleum's aggregate amounts of minimum lease payments under non-cancellable operating leases at 30 June 2019 under IAS 17 were as follows:

Commitments under operating leases	*Unaudited* 2019 US$M
Due not later than one year	58
Due later than one year and not later than five years	155
Due later than five years	189
Total	402

As at 30 June 2019, BHP Petroleum did not recognise any finance lease liabilities under IAS 17 'Leases'.

Movements in BHP Petroleum's right-of-use assets during the year are as follows:

	2021			2020		
	Land and buildings US$M	**Plant and equipment US$M**	**Total US$M**	Land and buildings US$M	Plant and equipment US$M	Total US$M
Net book value						
At the beginning of the financial year	**167**	**96**	**263**	-	-	-
Assets recognised on adoption of IFRS 16	**-**	**-**	**-**	233	128	361
Additions	**1**	**-**	**1**	4	9	13
Depreciation for the period	**(18)**	**(26)**	**(44)**	(23)	(41)	(64)
Impairments for the year	**(27)**	**-**	**(27)**	-	-	-
Derecognition due to lease modification	**-**	**(62)**	**(62)**	-	-	-
Transfers and other movements [(1)]	**-**	**-**	**-**	(47)	-	(47)
At the end of the financial year	**123**	**8**	**131**	167	96	263
- Cost	**190**	**29**	**219**	189	106	295
- Accumulated depreciation and impairments	**(67)**	**(21)**	**(88)**	(22)	(10)	(32)

(1) Transfer to net investment in sublease receivable, on commencement of sublease.

Right-of-use assets are included within the underlying asset classes in property, plant and equipment. Refer to Note 8 'Property, plant and equipment'.

Amounts recorded in the income statement and the cash flow statement for the year were:

	2021 US$M	2020 US$M	**Included within**
Income statement			
Depreciation of right-of-use assets	**37**	46	Profit from operations
Short-term, low-value and variable lease costs [(1)]	**52**	37	Profit from operations
Interest on lease liabilities	**7**	8	Financial expenses
Cash flow statement			
Principal lease payments	**38**	39	Cash flows from financing activities
Lease interest payments	**7**	7	Cash flows from operating activities

(1) Relates to US$36 million of variable lease costs (2020: US$22 million), US$13 million of short-term lease costs (2020: US$10 million) and US$3 million of low-value lease costs (2020: US$5 million). Variable lease costs include contracts for building leases, drill rig and equipment leases. These contracts contain variable lease payments based on usage and asset performance.

Recognition and measurement (following adoption of IFRS 16)

All leases with the exception of short-term (under 12 months) and low-value leases are recognised on the balance sheet, as a right-of-use asset and a corresponding interest-bearing liability. Lease liabilities are initially measured at the present value of the future lease payments from the lease commencement date and are subsequently adjusted to reflect the interest on lease liabilities, lease payments and any remeasurements due to, for example, lease modifications or changes to future lease payments linked to a rate. Lease payments are discounted using the interest rate implicit in the lease, where it is readily determinable. Where the implicit interest rate is not readily determinable, the interest payments are discounted at BHP Group's incremental borrowing rate, adjusted to reflect factors specific to the lease, including where relevant the currency, tenor and location of the lease.

In addition to containing a lease, the contractual arrangements may include non-lease components (for example, the maintenance and service costs associated with building leases). BHP Petroleum has elected to separate these non-lease components from the lease components in measuring lease liabilities.

Low-value and short-term leases are expensed to the income statement. Variable lease payments not dependent on an index or rate are excluded from lease liabilities and expensed to the income statement.

Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses and adjusted for any remeasurement of lease liabilities. The cost will initially correspond to the lease liability, adjusted for initial direct costs, lease payments made prior to lease commencement, capitalised provisions for closure and rehabilitation and any lease incentives.

Lease costs are recognised in the income statement over the lease term in the form of depreciation on the right-of-use asset and finance charges representing the unwind of the discount on the lease liability, replacing certain operating lease expenses previously reported under IAS 17.

Where BHP Petroleum is the operator of an unincorporated joint operation and all investors are parties to a lease, BHP Petroleum recognises its proportionate share of the lease liability and associated right-of-use asset. In the event BHP Petroleum is the sole signatory to a lease and therefore has the sole legal obligation to make lease payments, the lease liability is recognised in full. Where the associated right-of-use asset is sub-leased (under a finance sub-lease) to a joint operation, for instance where it is dedicated to a single operation and the joint operation has the right to direct the use of the asset, BHP Petroleum recognises its proportionate share of the right-of-use asset and a net investment in the lease, representing amounts to be recovered from the other parties to the joint operation. If BHP Petroleum is not party to the lease contract but sub-leases the associated right-of-use asset, the proportionate share of the right-of-use asset and a lease liability which is payable to the operator is recognised.

Key judgements and estimates

Where BHP Petroleum cannot readily determine the interest rate implicit in the lease, estimation is involved in the determination of the weighted average incremental borrowing rate to measure lease liabilities. The incremental borrowing rate reflects the rates of interest a lessee would have to pay to borrow over a similar term, with similar security, the funds necessary to obtain an asset of similar value to the right-of-use asset in a similar economic environment. Under BHP Group's portfolio approach to debt management, it does not specifically borrow for asset purchases. Therefore, the incremental borrowing rate is estimated with reference to BHP Group's corporate borrowing portfolio, adjusted to reflect the terms and conditions of the lease (including the impact of currency, credit rating of subsidiary entering into the lease and the term of the lease), at the commencement of the lease arrangement or the time of lease modification.

BHP Petroleum estimates stand-alone prices, where such prices are not readily observable, in order to allocate the contractual payments between lease and non-lease components.

IAS 17 Leases replaced by IFRS 16

BHP Petroleum applied accounting standard IAS 17 prior to adoption of IFRS 16 from 1 July 2019. Pre 1 July 2019, BHP Petroleum had no leases classified as finances leases under IAS17, however had a number of leases classified as operating leases as at 30 June 2019. Operating leases under IAS 17 are not capitalised and rental payments are included in the income statement on a straight-line basis over the lease term. Minimum lease payments under non-cancellable operating leases as at 30 June 2019 are disclosed above.

The effect of applying IFRS 16 has been disclosed in Note 25 'New and amended accounting standards'.

11. Intangible assets

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Net book value			
At the beginning of the financial year	**110**	104	149
Additions	**19**	44	6
Amortisation for the year (1)	**(32)**	(38)	(37)
Impairment for the year (2)	**(19)**	-	(14)
At the end of the financial year	**78**	110	104
- Cost	**248**	305	298
- Accumulated depreciation and impairments	**(170)**	(195)	(194)

(1) Included in income statement line item 'Expenses excluding net finance costs'.

(2) Refer to Note 12 'Impairment of non-current assets' for information on impairments.

Recognition and measurement

Where applicable, BHP Petroleum capitalises amounts paid for initial payments for the acquisition of identifiable intangible assets, such as software, licenses and initial payments for the acquisition of petroleum lease assets, where it is considered that they will contribute to future periods through revenue generation or reductions in cost. These assets, classified as finite life intangible assets, are carried in the balance sheet at the fair value of consideration paid less accumulated amortisation and impairment charges. Intangible assets with finite useful lives are amortised on a straight-line basis over their useful lives. The estimated useful lives are generally no greater than ten years.

Intangible assets primarily represent payments made for exploration leases, which have finite useful lives. Initial payments for the acquisition of intangible exploration lease assets are capitalised and amortised over the term of the permit. A regular review is undertaken of each area of interest to determine the appropriateness of continuing to carry forward costs in relation to that area. Capitalised costs are only carried forward to the extent that they are expected to be recovered through the successful exploitation of the area of interest or alternatively by its sale. To the extent that capitalised expenditure is no longer expected to be recovered, it is charged to the income statement.

Key judgements and estimates

Assessment of impairment indicators requires management's judgement. If a judgement is made that recovery of previously capitalised intangible petroleum lease assets is unlikely, the relevant amount will be charged to the income statement.

Determining the recoverable amount requires management to make certain estimates and assumptions as to future events and circumstances, in particular whether an economically viable extraction operation can be established.

Where indications of impairment exist for intangible assets, in the absence of quoted market prices, estimates are made regarding the present value of future post-tax cash flows. These estimates require management's judgement and assumptions and are subject to risk and uncertainty that may be beyond the control of BHP Petroleum; hence there is a possibility that changes in circumstances will materially alter projections, which may impact the recoverable amount of assets at each reporting date. The estimates are made from the perspective of a market participant and includes prices, future production volumes operating costs, tax attributes and discount rates.

12. Impairment of non-current assets

As at 30 June 2021	**Property, plant and equipment US$M**	**Intangibles US$M**	**Total US$M**
Previously capitalised exploration and evaluation cost (1)	**66**	**-**	**66**
Abandoned/relinquished exploration leases (2)	**-**	**19**	**19**
Leasehold fit out and fittings (3)	**42**	**-**	**42**
Total impairment of non-current assets	**108**	**19**	**127**

As at 30 June 2020	Property, plant and equipment US$M	Intangibles US$M	Total US$M
Other	11	-	11
Total impairment of non-current assets	11	-	11

Unaudited As at 30 June 2019	Property, plant and equipment US$M	Intangibles US$M	Total US$M
Previously capitalised exploration and evaluation cost (1)	7	13	20
Abandoned/relinquished exploration leases (2)	-	1	1
Total impairment of non-current assets	7	14	21

(1) Write-off of previously capitalised exploration and evaluation cost, following technical analysis of exploration results for various areas of interest.
(2) Write-off of capitalised exploration costs, where no further exploration and evaluation work was planned, following technical review of exploration portfolio.
(3) Write-off of leasehold fit out and fittings following restructuring, which resulted in a reduction in required office space.

For all impairments recognised in FY2021, FY2020 and FY2019, the recoverable amount of individual assets impaired was determined to be US$ nil following impairment review.

Recognition and measurement

Impairment tests for all assets are performed when there is an indication of impairment. If the carrying amount of the asset exceeds its recoverable amount, the asset is impaired, and an impairment loss is charged to the income statement so as to reduce the carrying amount in the balance sheet to its recoverable amount.

Where applicable, previously impaired assets are reviewed for possible reversal of previous impairment at each reporting date. Impairment reversal cannot exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognised for the asset. There were no reversals of impairment in the current or prior periods presented.

How recoverable amount is calculated

The recoverable amount is the higher of an asset's fair value less cost of disposal and its value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows.

Valuation methods

Fair value less cost of disposal (FVLCD)

FVLCD is an estimate of the amount that a market participant would pay for an asset, less the cost of disposal. FVLCD is generally determined using independent market assumptions to calculate the present value of the estimated future post-tax cash flows expected to arise from the continued use of the asset, including the anticipated cash flow effects of any capital expenditure to enhance production or reduce cost and its eventual disposal where a market participant may take a consistent view. Cash flows are discounted using an appropriate post tax market discount rate to arrive at a net present value of the asset, which is compared against the asset's carrying value. FVLCD may also take into consideration other market-based indicators of fair value.

Value in Use (VIU)

VIU is determined as the present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal or closure. VIU is determined by applying assumptions specific to our continued use and cannot take into account future development. These assumptions are different to those used in calculating FVLCD and consequently the VIU calculation is likely to give a different result (usually lower) to a FVLCD calculation.

Key judgements and estimates

Judgements: Assessment of indicators of impairment or impairment reversal require significant management judgement. Indicators of impairment may include changes in BHP Petroleum's operating and economic assumptions, including those arising from changes in reserves, updates to the commodity supply, demand and price forecasts, or the possible additional impacts from emerging risks such as those related to climate change and the transition to a low carbon economy and pandemics similar to COVID-19.

Climate Change

BHP Petroleum operated for all periods presented as part of BHP Group. As such, BHP Petroleum does not have a stand-alone climate change strategy. Future changes to BHP Group's climate change strategy, global decarbonisation signposts or physical risks to BHP Petroleum's assets may impact BHP Petroleum significant judgements and key estimates and result in material changes to financial results and the carrying values of certain assets and liabilities in future reporting periods.

When considering asset impairment assessment of BHP Petroleum, future impacts related to climate change and the transition to a lower carbon economy may include:

- demand for BHP Petroleum's commodities decreasing, due to policy, regulatory (including carbon pricing mechanisms), legal, technological, market or societal responses to climate change, resulting in a proportion of reserves becoming incapable of extraction in an economically viable fashion
- physical impacts related to acute risks resulting from increased severity of extreme weather events and those related to chronic risks resulting from longer-term changes in climate patterns.

Where sufficiently developed, the potential financial impacts on BHP Petroleum of climate change and the transition to a low carbon economy have been considered in the assessment of indicators of impairment, including:

- BHP Group's current assumptions relating to demand for commodities and carbon pricing, including their impact on BHP Group's long-term price forecasts applied by BHP Petroleum
- BHP Group's operational emissions reduction strategy

COVID-19

The macroeconomic disruptions relating to COVID-19 and mitigating actions enforced by health authorities create uncertainty in BHP Petroleum's operating and economic assumptions, including commodity prices, demand and supply volumes, operating costs and applied discount rates. However, given the long-lived nature of the majority of BHP Petroleum's assets, COVID-19 did not, in isolation, result in the identification of indicators of impairment for BHP Petroleum's asset values at 30 June 2021. Due to ongoing uncertainty as to the extent and duration of COVID-19 restrictions and the overall impact on economic activity, actual experience may materially differ from internal forecasts and may result in the reassessment of indicators of impairment for BHP Petroleum's assets in future reporting periods.

Estimates: BHP Petroleum performs a recoverable amount determination for an asset when there is an indication of impairment or impairment reversal.

When the recoverable amount is measured by reference to FVLCD, in the absence of quoted market prices or binding sale agreement, estimates are made regarding the present value of future post-tax cash flows. These estimates are made from the perspective of a market participant and include prices, future production volumes, operating costs, capital expenditure, closure and rehabilitation costs, tax attributes, risking factors applied to cash flows and discount rates. Reserves and resources are included in the assessment of FVLCD to the extent that it is considered probable that a market participant would attribute value to them.

When recoverable amount is measured using VIU, estimates are made regarding the present value of future cash flows based on internal budgets and forecasts and life of asset plans. Key estimates are similar to those identified for FVLCD, although some assumptions and values may differ as they reflect the perspective of management rather than a market participant.

All estimates require management judgements and assumptions and are subject to risk and uncertainty that may be beyond the control of BHP Petroleum; hence, there is a possibility that changes in circumstances will materially alter projections, which may impact the recoverable amount of assets at each reporting date.

The most significant estimates impacting BHP Petroleum's recoverable amount determinations include:

Commodity prices

Commodity prices were based on BHP Petroleum's latest internal forecasts which assume that short-term market prices will revert to BHP Petroleum's assessment of long-term prices. These price forecasts reflect management's long-term views of global supply and demand, built upon past experience of the commodity markets and are benchmarked with external sources of information such as analyst forecasts. Prices are adjusted based upon premiums or discounts applied to global price markers based on the location, nature and quality produced, or to take into account contracted prices.

Future production volumes

Estimated production volumes were based on detailed data and took into account development plans established by management as part of BHP Petroleum's long-term planning process. When estimating FVLCD, assumptions reflect all reserves and resources that a market participant would consider when valuing assets, which in some cases are broader in scope than the reserves that would be used in a VIU test. In determining FVLCD, risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved.

BHP Petroleum Assets

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Operating costs and capital expenditures

Operating costs and capital expenditures are generally based on internal budgets and forecasts and life of asset plans. Cost assumptions reflect management's experience and expectations. In the case of FVLCD, cash flow projections include the anticipated cash flow effects of any capital expenditure to enhance production or reduce cost where a market participant may take a consistent view. VIU does not take into account future development.

Discount rates

BHP Petroleum uses real post-tax discount rates applied to real post-tax cash flows. The discount rates are derived using BHP Group's weighted average cost of capital methodology. Adjustments to the rates are made for any risks that are not reflected in the underlying cash flows.

13. Trade and other payables

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Trade payables external	**641**	491	625
Other payables	**278**	280	304
Total trade and other payables	**919**	771	929

14. Closure and rehabilitation provisions

A reconciliation of the changes in the closure and rehabilitation provisions is shown in the following table:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
At the beginning of the financial year	**3,595**	2,300	1,980
Capitalised amounts for operating sites:			
Change in estimate	**131**	486	334
Impact of change in discount rate	**-**	775	-
Exchange translation	**162**	(24)	(42)
Adjustments charged/(credited) to the income statement for closed sites:			
Change in estimate	**17**	19	(11)
Impact of change in discount rate	**-**	22	-
Exchange translation	**10**	(2)	(3)
Other adjustments to the provision:			
Amortisation of discounting impacting net finance costs	**94**	106	111
Acquisition of subsidiaries and operations	**179**	-	-
Divestment and demerger of subsidiaries and operations	**(81)**	-	-
Expenditure on closure and rehabilitation activities	**(152)**	(86)	(67)
Exchange variations impacting foreign currency translation reserve	**2**	(1)	(2)
At the end of the financial year	**3,957**	3,595	2,300
Comprising:			
Current	**141**	162	205
Non-current	**3,816**	3,433	2,095
Operating sites	**3,623**	3,292	2,043
Closed sites	**334**	303	257

BHP Petroleum is required to rehabilitate sites and associated facilities at the end of, or in some cases, during the course of production, to a condition acceptable to the relevant authorities, as specified in license requirements and BHP Group's environmental performance requirements as set out within the BHP Group Charter.

The key components of closure and rehabilitation activities are:

- the removal of all unwanted infrastructure associated with an operation
- the return of disturbed areas to a safe, stable, productive and self-sustaining condition, consistent with agreed end use

Recognition and measurement

Provisions for closure and rehabilitation are recognised by BHP Petroleum when:

- it has a present legal or constructive obligation as a result of past events;
- it is more likely than not that an outflow of resources will be required to settle the obligation;
- the amount can be reliably estimated.

Initial recognition

Closure and rehabilitation provisions are initially recognised when an environmental disturbance first occurs. The individual site provisions are an estimate of the expected value of future cash flows required to rehabilitate the relevant site using current restoration standards and techniques and taking into account risks and uncertainties. Individual site provisions are discounted to their present value using currency specific discount rates aligned to the estimated timing of cash outflows.

When provisions for closure and rehabilitation are initially recognised, the corresponding cost is capitalised as an asset, representing part of the cost of acquiring the future economic benefits of the operation.

Subsequent measurement

The closure and rehabilitation asset, recognised within property, plant and equipment, is depreciated over the life of the operations. The value of the provision is progressively increased over time as the effect of discounting unwinds, resulting in an expense recognised in net finance costs.

The closure and rehabilitation provision is reviewed at each reporting date to assess if the estimate continues to reflect the best estimate of the obligation. If necessary, the provision is remeasured to account for factors, including:

- revisions to estimated reserves, resources and lives of operations;
- developments in technology;
- regulatory requirements and environmental management strategies;
- changes in the estimated extent and costs of anticipated activities, including the effects of inflation and movements in foreign exchange rates, where applicable;
- movements in interest rates affecting the discount rate applied.

Changes to the closure and rehabilitation estimate for operating sites are added to, or deducted from, the related asset and amortised on a prospective basis accordingly over the remaining life of the operation, generally applying the UoP method.

Costs arising from unforeseen circumstances, such as the contamination caused by unplanned discharges, are recognised as an expense and liability when incurred.

Closed sites

Where future economic benefits are no longer expected to be derived through operations, changes to the associated closure and remediation costs are charged to the income statement in the period identified.

Key estimates

The recognition and measurement of closure and rehabilitation provisions requires the use of significant estimates and assumptions, including, but not limited to:

- the extent (due to legal or constructive obligations) of potential activities required for the removal of infrastructure and rehabilitation activities;
- costs associated with future rehabilitation activities;
- applicable discount rates;
- the timing of cash flows and ultimate closure of operations.

The extent and cost of future rehabilitation activities may also be impacted by the potential physical impacts of climate change. In estimating the potential cost of closure activities, BHP Petroleum considers factors such as long-term weather outlooks, for example forecast changes in rainfall patterns and the cost of performing rehabilitation activities.

While progressive closure is performed across a number of operations, significant rehabilitation activities are generally undertaken at the end of the production life at the individual sites, the estimated timing of which is informed by BHP Petroleum's current assumptions relating to demand for commodities and their impact on BHP Petroleum's long-term price forecasts. Remaining production lives range from 1-36 years with an average for all sites, weighted by current closure provision, of approximately 17 years. The discount rates applied to BHP Petroleum's closure and rehabilitation provisions are determined by reference to the currency of the closure cash flows, the period over which the cash flows will be incurred and prevailing market interest rates (where available). The effect of prior year (FY2020) changes to discount rates was an increase of approximately US$797 million in the closure and rehabilitation provision. There were no changes to the discount in the current year or FY2019.

While the closure and rehabilitation provisions reflect management's best estimates based on current knowledge and information, further studies and detailed analysis of the closure activities for individual assets will be performed as the assets near the end of their operational life and/or detailed closure plans are required to be submitted to relevant regulatory authorities. Such studies and analysis can impact the estimated costs of closure activities. Estimates can also be impacted by the emergence of new restoration techniques, changes in regulatory requirements for rehabilitation, risks relating to climate change and the transition to a low carbon economy and experience at other operations. These uncertainties may result in future actual expenditure differing from the amounts currently provided for in the balance sheet.

Sensitivity

A further 0.5 per cent decrease in the discount rates applied at 30 June 2021 would result in an increase to the closure and rehabilitation provision of approximately US$245 million, an increase in property, plant and equipment of approximately US$241 million in relation to operating sites and an income statement charge of approximately US$4 million in respect of closed sites. In addition, the change would result in an increase of approximately US$46 million in depreciation expense and a US$13 million reduction in net finance costs for the year ending 30 June 2022.

Given the long-lived nature of the majority of BHP Petroleum's assets, closure activities are generally not expected to occur for a significant period of time. A one-year acceleration in forecast cash flows of BHP Petroleum's closure and rehabilitation provisions, in isolation, would result in an increase to the provision of approximately US$53 million, an increase in property, plant and equipment of US$46 million in relation to operating sites and an income statement charge of US$7 million in respect of closed sites.

15. Other provisions

The disclosure below excludes closure and rehabilitation provisions (refer to Note 14 'Closure and rehabilitation provisions'), employee benefits, restructuring and post-retirement employee benefits provisions (refer to Note 18 'Employee benefits, restructuring and post-retirement employee benefits provisions').

A reconciliation of changes in other provisions for other liabilities is shown in the following table:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
At the beginning of the financial year	**168**	259	229
Charge/(credit) for the year:			
Disposals	**(1)**	-	30
Underlying	**122**	94	193
Discounting	**1**	3	10
Exchange variations	**6**	-	-
Released during the year	**(7)**	(43)	(69)
Utilisation	**(57)**	(85)	(138)
Transfers and other movements	**1**	(60)	4
At the end of the financial year	**233**	168	259
Comprising:			
Current	**137**	145	137
Non-current	**96**	23	122

16. Contingent liabilities

BHP Petroleum's total contingent liabilities for subsidiaries and joint operations as at 30 June 2021 is US$759 million (2020: US$687 million, 2019: US$713 million).

A contingent liability is a possible obligation arising from past events and whose existence will be confirmed only by occurrence or non-occurrence of one or more uncertain future events not wholly within the control of BHP Petroleum. A contingent liability may also be a present obligation arising from past events but is not recognised on the basis that an outflow of economic resources to settle the obligation is not viewed as probable, or the amount of the obligation cannot be reliably measured.

When BHP Petroleum has a present obligation, an outflow of economic resources is assessed as probable and the obligation can be reliably measured, a provision is recognised. BHP Petroleum's contingent liabilities primarily include possible obligations for litigation, uncertain tax and royalty matters, open regulatory audits and various other claims, for which the timing of resolution and potential economic outflow is uncertain. Obligations assessed as having probable future economic outflows capable of reliable measurement are provided at reporting date and matters assessed as having possible future economic outflows capable of reliable measurement are included in the total amount of contingent liabilities above.

Uncertain tax and royalty matters	BHP Petroleum is subject to a range of taxes and royalties across many jurisdictions, the application of which is uncertain in some regards. Changes in tax law, changes in interpretation of tax law, periodic challenges and disagreements with tax authorities and legal proceedings result in uncertainty of the outcome of the application of taxes and royalties to BHP Petroleum's business. Areas of uncertainty at reporting date include the application of taxes and royalties to BHP Petroleum's cross-border operations and transactions. To the extent uncertain tax and royalty matters give rise to a contingent liability, an estimate of the potential liability is included within the above total, where it is capable of reliable measurement.

Open regulatory audits	Under contractual terms, BHP Petroleum is subject to regulatory and joint venture partner audit activity on a routine basis. BHP Petroleum has included contingent liabilities for various periods remaining under audit with regulatory bodies; primarily related to cost recovery claimed by BHP Petroleum, as operator, under contractual terms. To the extent that outcomes of audits remain uncertain, these may give rise to a contingent liability. An estimate of the potential outflow is included within the above total, where it is capable of reliable measurement.

BHP Petroleum has entered into various counterindemnities of bank and performance guarantees related to its own future performance, which are entered into in the normal course of business. The likelihood of these guarantees being called upon is considered remote.

17. Financial risk management

Capital Management

BHP Petroleum has operated for all periods presented as part of BHP Group, with capital of BHP Petroleum managed in accordance with BHP Group capital management strategies and priorities. BHP Group defines capital as the total equity of BHP Group. BHP Group seeks to maintain a strong balance sheet and deploys its capital with reference to BHP Group Capital Allocation Framework. BHP Group monitors capital using BHP Group's net debt balance and BHP Group's gearing ratio, being the ratio of net debt to net debt plus net assets. Capital is managed with the goal of maintaining levels of gearing designed to optimise the cost of capital and return on capital employed, while also growing the business consistently through project developments and acquisitions across BHP Group portfolio of assets.

BHP Petroleum's strategy, as part of BHP Group, is to focus on upstream, large, long life, low cost and expandable assets. BHP Group and BHP Petroleum continually review its portfolio to identify assets that do not fit this strategy. BHP Group, together with BHP Petroleum, will invest capital in assets that fit its strategy.

Financial risks

BHP Petroleum has operated for all periods presented as part of BHP Group; with BHP Petroleum's financial risks considered and managed by the BHP Group Financial Risk Management Committee (FRMC) under authority delegated by the BHP Group Chief Executive Officer.

Financial risk management strategy

The financial risks arising from BHP Petroleum's operations are market risk, including risks associated with movements in interest rates, currency exchange rates and commodity prices, liquidity risk and credit risk. These risks arise in the normal course of business and BHP Petroleum manages its exposure to them in accordance with the BHP Group Portfolio Risk Management Strategy.

Primary responsibility for identification and control of financial risks rests with the BHP Group's FRMC under authority delegated by the BHP Group Chief Executive Officer.

The FRMC reviews the effectiveness of internal controls related to commodity price risk, counterparty credit risk, financing risk, interest rate risk and insurance. The FRMC monitors the financial risk management policies and exposures and approves financial transactions within the scope of its authority.

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BHP Petroleum's risk exposure and responses

BHP Petroleum's operations expose it to a variety of financial risks that include commodity price risk, liquidity risk, credit risk, currency risk and interest rate risk.

The individual risks along with the responses of BHP Petroleum are set out below.

Credit risk

Trade receivables generally have terms of less than 30 days. BHP Petroleum has no material concentration of credit risk with any single counterparty.

Refer to Note 6 'Trade and other receivables' for details on BHP Petroleum's credit risk.

Commodity price risk

BHP Petroleum is exposed to movements in the prices of the products that are sold as commodities on the market. While fluctuations occur in the market, it would take significant decreases over an extended period of time to have a material effect on results of operations.

Interest rate risk

BHP Petroleum is exposed to interest rate risk on its outstanding borrowings and short-term cash deposits from the possibility that changes in interest rate will affect future cash flows. BHP Petroleum does not have exposure to external facing debt - with all current debt funding provided by BHP Group entities.

The majority of BHP Petroleum's debt is issued at London Interbank Offered Rate (LIBOR) interest rates. Based on the net debt position as at 30 June 2021, it is estimated that a one percentage point increase in the US LIBOR interest rate will decrease BHP Petroleum's equity and profit after taxation by US$67 million (2020: decrease of US$98 million, 2019: decrease of US$112 million). This assumes the change in interest rates is effective from the beginning of the financial year and the net debt balances are constant over the year.

Interest rate benchmark reform

LIBOR and other benchmark interest rates are expected to be replaced by alternative risk-free rates (ARR) by the end of CY2021 as part of inter-bank offer rate (IBOR) reform. BHP Group has established a project to assess the implications of IBOR reform across BHP Group and to manage and execute the transition from current discontinuing IBORs rates to ARR, including updating policies, systems and processes.

BHP Petroleum has early adopted amendments to IFRS 9 'Financial Instruments', IFRS 7 'Financial Instruments: Disclosures' and IFRS 16 'Leases' in relation to IBOR reform.

Currency risk

The US dollar is the predominant functional currency within BHP Petroleum and as a result, currency exposures arise from transactions and balances in currencies other than the US dollar. BHP Petroleum's potential currency exposures comprise:

- translational exposure in respect of non-functional currency monetary items
- transactional exposure in respect of non-functional currency expenditure and revenues.

BHP Petroleum Assets

Notes to the Financial Statements

The following table shows the foreign currency risk arising from financial assets and liabilities, which are denominated in currencies other than the US dollar:

Net financial (liabilities)/assets - by currency of denomination	**2021 US$M**	2020 US$M	*Unaudited* 2019 US$M
Australian dollars	**(95)**	68	101
Other	**37**	6	15
Total	**(58)**	74	116

The principal non-functional currency exposure for BHP Petroleum is the Australian dollar. Based on BHP Petroleum's net financial assets and liabilities as at 30 June 2021, a weakening of the US dollar against this currency (one cent strengthening in the Australian dollar), with all other variables held constant, would decrease BHP Petroleum's equity and profit after taxation by US$1 million (2020: increase of US$1 million, 2019: increase of US$1 million).

Liquidity risk

BHP Petroleum's liquidity risk arises from the possibility that it may not be able to settle or meet its obligations as they fall due. The risk is managed as part of BHP Group's Portfolio Risk Management Strategy and within BHP Group's overall Cash Flow at Risk (CFaR) limit.

BHP Petroleum Assets

Notes to the Financial Statements

The tables below summarise the timing of cash outflows relating to payables, including those to BHP Group entities and leases:

2021 US$M	**Trade and other payables**	**Payables to BHP Group**	**Leases**	**Total**
Due for payment:				
Within 1 year	**919**	**2,001**	**41**	**2,961**
1 to 2 years	**-**	**10,347**	**37**	**10,384**
2 to 3 years	**-**	**-**	**35**	**35**
3 to 4 years	**-**	**-**	**33**	**33**
4 to 5 years	**-**	**-**	**23**	**23**
Above 5 years	**-**	**-**	**133**	**133**
Total	**919**	**12,348**	**302**	**13,569**

2020 US$M	Trade and other payables	Payables to BHP Group	Leases	Total
Due for payment:				
Within 1 year	771	6,533	70	7,374
1 to 2 years	-	-	70	70
2 to 3 years	-	10,347	63	10,410
3 to 4 years	-	-	35	35
4 to 5 years	-	-	32	32
Above 5 years	-	-	156	156
Total	771	16,880	426	18,077

Unaudited 2019 US$M	Trade and other payables	Payables to BHP Group	Total
Due for payment:			
Within 1 year	929	6,520	7,449
1 to 2 years	-	3,993	3,993
2 to 3 years	-	-	-
3 to 4 years	-	10,347	10,347
4 to 5 years	-	-	-
Above 5 years	-	-	-
Total	929	20,860	21,789

* Refer to Note 25 ‘New and amended accounting standards and interpretations’.

Fair value measurement

All financial assets and financial liabilities are initially recognised at the fair value of consideration paid or received, net of transaction costs as appropriate and subsequently carried at fair value or amortised cost. The financial assets and liabilities are presented by class in the tables below at their carrying values, which generally approximate to fair values.

	IFRS 13 Fair value hierarchy Level	**IFRS 9 Classification**	**2021 US$M**	2020 US$M	*Unaudited* 2019 US$M
Cash and cash equivalents		Amortised cost	**776**	325	1,398

BHP Petroleum Assets

Notes to the Financial Statements

Trade and other receivables		Amortised cost	**1,065**	785	873
Receivables from BHP Group		Amortised cost	**5,526**	12,424	15,871
Other financial assets [1][2]	2,3	Fair value through profit or loss	**51**	93	70
Total financial assets			**7,418**	13,627	18,212
Trade and other payables		Amortised cost	**919**	771	929
Payables to BHP Group		Amortised cost	**12,348**	16,880	20,860
Other financial liabilities	3	Fair value through profit or loss	**9**	6	2
Interest bearing liabilities		Amortised cost	**269**	383	17
Total financial liabilities			**13,545**	18,040	21,808

(1) Includes financial assets of US$51 million (2020: US$78 million, 2019: US$70 million) categorised as Level 3. Significant items are derivatives embedded in physical commodity purchase and sales contract and contingent consideration receivable.
(2) Includes investment in debt security of $0 (2020: US$15 million, 2019: $0) categorised as Level 2.

BHP Petroleum uses fair value to measure certain of its assets and liabilities in the combined financial statements. Fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, that is, an exit price from the perspective of a market participant that holds the asset or owes the liability.

For financial assets and liabilities carried at fair value, BHP Petroleum uses the following to categorise the method used based on the lowest level input that is significant to the fair value measurement as a whole:

Level 1 – Based on quoted process (unadjusted) in active markets for identical financial assets and liabilities

Level 2 – Based on inputs other than quoted prices included within Level 1 that are observable for financial asset or liability

Level 3 – Based on inputs not observable in the market using appropriate valuation models, including discounted cash flow modelling

If, at inception of a contract, the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognised in the income statement but deferred on the balance sheet and is commonly known as 'day-one gain or loss'. This deferred gain or loss is recognised in the income statement over the life of the contract until substantially all the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognised in the income statement. Changes in valuation subsequent to the initial valuation at inception of a contract are recognised immediately in the income statement.

The carrying value of Other financial assets and Other financial liabilities includes an embedded derivative resulting from a physical commodity (gas) purchase and sale contract in Trinidad and Tobago. The carrying value of the embedded derivative at 30 June 2021 was a net liability of US$4 million (2020: net asset of US$26 million, 2019: net asset of US$23 million).

Within Other financial assets, BHP Petroleum has also recognised a receivable for contingent consideration of US$46 million for each reporting period. The contingent consideration asset was recognised on sale of an interest in the Scarborough gas project to Woodside Petroleum Limited in 2016. Where a positive final investment decision is made, a contingent payment of US$150 million will be payable to BHP Petroleum.

The valuation techniques used by BHP Petroleum to measure fair value include the use of internally developed methodologies and models that result in management's best estimate of fair value. Inputs used in the valuation include, but are not limited to, future commodity prices, market discount rates and consideration of risks specific to the asset or liability being fair valued.

The following table presents the impact of activity for financial instruments classified as Level 3 in the fair value hierarchy as at 30 June 2021, 2020 and 2019:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Fair value at beginning of year	**72**	68	61
Gains/(losses) recognised in income statement:	**(10)**	29	22
Settlements	**(20)**	(25)	(15)
Net fair value at end of year	**42**	72	68

18. Employee benefits, restructuring and post-retirement employee benefits provisions

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Employee benefits provisions (1)	**147**	121	114
Restructuring provisions (2)	**31**	8	26
Post-retirement employee benefits provisions	**248**	253	246
Total provisions	**426**	382	386
Comprising:			
Current	**178**	129	140
Non-current	**248**	253	246

(1) The expenditure associated with total employee benefits will occur in a pattern consistent with when employees choose to exercise their entitlement to benefits.

(2) Total restructuring provisions include provisions for terminations.

2021 US$M	Employee benefits [1]	Restructuring [2]	Post-retirement employee benefits	Total
At the beginning of the financial year	121	8	253	382
Charge/(credit) for the year:				
Underlying	144	29	20	193
Discounting	-	-	11	11
Net interest expense	-	-	(4)	(4)
Exchange variations	1	-	-	1
Released during the year	(18)	-	-	(18)
Remeasurement gains taken to retained earnings	-	-	(2)	(2)
Utilisation	(101)	(6)	(30)	(137)
At the end of the financial year	**147**	**31**	**248**	**426**

[1] The expenditure associated with total employee benefits will occur in a pattern consistent with when employees choose to exercise their entitlement to benefits.
[2] Total restructuring provisions include provisions for terminations.

Recognition and measurement

Provisions are recognised by BHP Petroleum when:

- there is a present legal or constructive obligation as a result of past events
- it is more likely than not that a permanent outflow of resources will be required to settle the obligation
- the amount can be reliably estimated and measured at the present value of management's best estimate of the cash outflow required to settle the obligation at reporting date.

Provision	Description
Employee benefits	Liabilities for annual leave and any accumulating sick leave accrued up until the reporting date that are expected to be settled within 12 months are measured at the amounts expected to be paid when the liabilities are settled. To the extent uncertain tax and royalty matters give rise to a contingent liability, an estimate of the potential liability is included within the above total, where it is capable of reliable measurement. Liabilities for long service leave are measured as the present value of estimated future payments for the services provided by employees up to the reporting date and disclosed within employee benefits. Liabilities that are not expected to be settled within 12 months are discounted at the reporting date using market yields of high-quality corporate bonds or government bonds for countries where there is no deep market for corporate bonds. The rates used reflect the terms to maturity and currency that match, as closely as possible, the estimated future cash outflows. In relation to industry-based long service leave funds, BHP Petroleum's liability, including obligations for funding shortfalls, is determined after deducting the fair value of dedicated assets of such funds.

	Liabilities for unpaid wages and salaries are recognised in other creditors.
Restructuring	Restructuring provisions are recognised when: - BHP Petroleum has a detailed formal plan identifying the business or part of the business concerned, the location and approximate number of employees affected, a detailed estimate of the associated costs and an appropriate timeline - the restructuring has either commenced or been publicly announced and can no longer be withdrawn. Payments falling due greater than 12 months after the reporting date are discounted to present value.

Post-retirement employee benefits

BHP Petroleum operates or participates in a number of pension (including superannuation) schemes throughout the world. The funding of the schemes complies with local regulations. The assets of the schemes are generally held separately from those of BHP Petroleum and are administered by trustees or management boards.

Schemes/Obligations	Description
Defined contribution pension schemes and multi-employer pension schemes	For defined contribution schemes or schemes operated on an industry-wide basis where it is not possible to identify assets attributable to the participation by our employees, the pension charge is calculated on the basis of contributions payable. BHP Petroleum contributed US$42 million during the financial year (2020: US$37 million, 2019: US$68 million) to defined contribution plans and multi-employer defined contribution plans. These contributions are expensed as incurred.
Defined benefit pension schemes	For defined benefit pension schemes, the cost of providing pensions is charged to the income statement so as to recognise current and past service costs, net interest cost on the net defined benefit obligations/plan assets and the effect of any curtailments or settlements. Remeasurement gains and losses are recognised directly in equity. An asset or liability is consequently recognised in the balance sheet based on the present value of defined benefit obligations less the fair value of plan assets, except that any such asset cannot exceed the present value of expected refunds from and reductions in future contributions to the plan. Defined benefit obligations are estimated by discounting expected future payments using market yields at the reporting date on high-quality corporate bonds in countries that have developed corporate bond markets. However, where developed corporate bond markets do not exist, the discount rates are selected by reference to national government bonds. In both instances, the bonds are selected with terms to maturity and currency that match, as closely as possible, the estimated future cash flows. BHP Petroleum has closed all defined benefit pension schemes to new entrants. Defined benefit pension schemes remain operating in Australia and the United States for existing members. Full actuarial valuations are prepared and updated annually to 30 June by local actuaries for all schemes. BHP Petroleum operates final salary schemes (that provide final salary benefits only), non-salary related schemes

	(that provide flat dollar benefits) and mixed benefit schemes (that consist of a final salary defined benefit portion and a defined contribution portion).
Defined benefit post-retirement medical schemes	BHP Petroleum operates a number of post-retirement medical schemes in the United States and certain BHP Group companies provide post-retirement medical benefits to qualifying retirees. In some cases, the benefits are provided through medical care schemes to which BHP Group, the employees, the retirees and covered family members contribute. Full actuarial valuations are prepared by local actuaries for all schemes. These schemes are recognised on the same basis as described for defined benefit pension schemes. All of the post-retirement medical schemes are unfunded.

Risk

BHP Petroleum defined benefit schemes/obligations expose BHP Petroleum to a number of risks, including asset value volatility, interest rate variations, inflation, longevity and medical expense inflation risk.

Recognising this, BHP Petroleum has adopted an approach of moving away from providing defined benefit pensions. The majority of BHP Petroleum's sponsored defined benefit pension schemes have been closed to new entrants for many years. Existing benefit schemes and the terms of employee participation in these schemes are reviewed on a regular basis.

Actuarial assumptions

Significant actuarial assumptions for the determination of the defined benefit obligation are discount rate, expected salary increase and mortality. The sensitivity analyses below have been determined based on reasonably possible changes of the respective assumptions occurring at the end of the reporting period, while holding all other assumptions constant.

The material financial assumptions used to estimate the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year and are used to evaluate the accrued benefit obligation at 30 June and pension expense for the following year.

	Defined benefit pension schemes			**Defined benefit post-retirement medical schemes**		
			Unaudited			*Unaudited*
	2021	2020	2019	**2021**	2020	2019
Key assumptions used to determine benefit obligation:						
Discount rate	**3.09%**	2.51%	3.47%	**2.56%**	2.40%	3.27%
Post-retirement health care trend rate - initial	**-**	-	-	**4.22%**	4.41%	4.52%
Post-retirement health care trend rate - ultimate	**-**	-	-	**4.03%**	4.06%	4.08%

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	Defined benefit pension schemes			Defined benefit post-retirement medical schemes		
			Unaudited			*Unaudited*
	2021	2020	2019	**2021**	2020	2019
Key assumptions used to determine benefit expense:						
Discount rate	**2.51%**	3.48%	4.11%	**2.40%**	3.27%	4.00%
Post-retirement health care trend rate - initial	**-**	-	-	**4.41%**	4.52%	4.84%
Post-retirement health care trend rate - ultimate	**-**	-	-	**4.06%**	4.08%	4.11%

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to applicable published tables adjusted where appropriate to reflect the experience of BHP Petroleum and an extrapolation of past longevity improvements into the future.

BHP Petroleum's most substantial pension liabilities are in the US where mortality assumptions applied are as follows:

			Unaudited
	2021	**2020**	2019
Life Expectancy of a Male aged 65 now	**21.561**	21.451	21.386
Life Expectancy of a Male aged 65 in 15 years	**22.458**	22.358	22.303
Life Expectancy of a Female aged 65 now	**23.285**	23.197	23.137
Life Expectancy of a Female aged 65 in 15 years	**24.116**	23.379	23.984

Fund assets

BHP Petroleum follows a coordinated strategy for the funding and investment of its defined benefit pension schemes (subject to meeting all local requirements). BHP Petroleum aims for the value of defined benefit pension scheme assets to be maintained at close to the value of the corresponding benefit obligations, allowing for some short-term volatility. Scheme assets are invested in a diversified range of asset classes, predominantly comprising bonds and equities.

BHP Petroleum aims to progressively shift defined benefit pension scheme assets towards investments that match the anticipated profile of the benefit obligations, as funding levels improve, and benefit obligations mature. Over time, this is expected to result in a further reduction in the total exposure of pension scheme assets to equity markets. For pension schemes that pay lifetime benefits, BHP Petroleum may consider and support the purchase of annuities to back these benefit obligations if it is commercially sensible to do so.

Net liability recognised in the Consolidated Balance Sheet

The net liability recognised in the Consolidated Balance Sheet is as follows:

	Defined benefit pension schemes/post-employment obligations			Post-retirement medical schemes		
			Unaudited			*Unaudited*
	2021 US$M	2020 US$M	2019 US$M	**2021 US$M**	2020 US$M	2019 US$M
Present value of funded defined benefit obligation	**163**	172	172	**-**	-	-
Present value of unfunded defined benefit obligation	**111**	97	104	**154**	166	154
Fair value of defined benefit scheme assets	**(180)**	(182)	(184)	**-**	-	-
Scheme deficit	**94**	87	92	**154**	166	154
Unrecognised surplus	**-**	-	-	**-**	-	-
Unrecognised past service credits	**-**	-	-	**-**	-	-
Adjustment for employer contributions tax	**-**	-	-	**-**	-	-
Net liability recognised in the Consolidated Balance Sheet	**94**	87	92	**154**	166	154

BHP Petroleum has no legal obligation to settle these liabilities with any immediate contributions or additional one-off contributions. BHP Petroleum intends to continue to contribute to each defined benefit pension and post-retirement medical scheme in accordance with the latest recommendations of each scheme actuary.

Employee share ownership plans

Awards, in the form of the right to receive ordinary shares in either BHP Group Limited or BHP Group Plc, have been granted under the following employee share ownership plans: Cash and Deferred Plan (CDP), Short-Term Incentive Plan (STIP), Long-Term Incentive Plan (LTIP), Management Award Plan (MAP), Transitional and Commencement Key Management Personnel awards and the all-employee share plan, Shareplus.

Some awards are eligible to receive a cash payment, or the equivalent value in shares, equal to the dividend amount that would have been earned on the underlying shares awarded to those participants (the Dividend Equivalent Payment, or DEP). The DEP is provided to the participants once the underlying shares are allocated or transferred to them. Awards under the plans do not confer any rights to participate in a share issue; however, there is discretion under each of the plans to adjust the awards in response to a variation in the share capital of BHP Group Limited or BHP Group Plc.

Employee share awards pre-tax expense is US$36 million (2020: US$39 million, 2019: US$45 million).

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Fair value and assumptions in the calculation of fair value for awards issued

2021	Closing number of shares at the end of the financial year	Weighted average fair value of awards granted during the year US$	Risk-free interest rate	Estimated life of awards	Share price at grant date	Estimated volatility of share price	Dividend yield
BHP Group Limited							
CDP awards	50,980	25.28	n/a	2 and 5 years	A$35.90	n/a	n/a
STIP awards	6,628	25.28	n/a	2 years	A$35.90	n/a	n/a
LTIP awards [(1)]	328,709	14.68	0.25%	5 years	A$35.90/A$33.81/A$38.56	28.0%	n/a
MAP awards [(2)]	3,867,213	22.88	n/a	1-5 years	A$38.36/A$36.91/A$35.90/A$45.88	n/a	4.90%
Shareplus	333,738	28.35	0.21%	3 years	A$30.19	n/a	5.59%
BHP Group Plc							
Shareplus	481	15.32	0.12%	3 years	£12.11	n/a	6.40%

(1) Includes LTIP awards granted on 20 October 2020, 2 November 2020 and 1 December 2020.
(2) Includes MAP awards granted on 21 August 2020, 24 September 2020, 20 October 2020 and 7 April 2021.

Recognition and measurement

The fair value at grant date of equity-settled share awards is charged to the income statement over the period for which the benefits of employee services are expected to be derived. The fair values of awards granted were estimated using a Monte Carlo simulation methodology and Black-Scholes option pricing technique and consider the following factors:

- exercise price
- expected life of the award
- current market price of the underlying shares
- expected volatility using an analysis of historic volatility over different rolling periods. For the LTIP, it is calculated for all sector comparators and the published MSCI World index
- expected dividends
- risk-free interest rate, which is an applicable government bond rate
- market-based performance hurdles
- non-vesting conditions

Where awards are forfeited because non-market-based vesting conditions are not satisfied, the expense previously recognised is proportionately reversed.

The tax effect of awards granted is recognised in income tax expense, except to the extent that the total tax deductions are expected to exceed the cumulative remuneration expense. In this situation, the excess of the associated current or deferred tax is recognised in equity and forms part of the employee share awards reserve. The fair value of awards as presented in the tables above represents the fair value at grant date.

In respect of employee share awards, BHP Group utilises the Billiton Employee Share Ownership Trust and the BHP Billiton Limited Employee Equity Trust. The trustees of these trusts are independent companies, resident in Jersey. The trusts use funds provided by BHP Group to acquire ordinary shares to enable awards to be made or satisfied. The ordinary shares may be acquired by purchase in the market or by subscription at not less than nominal value. These entities are outside BHP Petroleum boundary and are not included as part of BHP Petroleum's combined financial statements.

19. Subsidiaries

BHP Petroleum's financial statements include the combination of subsidiaries as described in Note 1 'Organisation and summary of significant accounting policies'.

Significant subsidiaries are those with the most significant contribution to BHP Petroleum's net profit or net assets. BHP Petroleum's interest in significant subsidiaries' results is listed in the table below:

Significant subsidiaries	Country of incorporation
BHP (Trinidad-3A) Ltd	Trinidad and Tobago
BHP Billiton (Trinidad-2C) Ltd.	Canada
BHP Petroleum (Australia) Pty Ltd	Australia
BHP Billiton Petroleum (Deepwater) Inc.	US
BHP Petroleum (International Exploration) Pty Ltd	Australia
BHP Petroleum (Bass Strait) Pty Ltd	Australia
BHP Petroleum (North West Shelf) Pty Ltd	Australia

BHP Petroleum's interest in these significant subsidiaries in FY2021, FY2020 and FY2019 was 100 per cent and the principal activity of each significant subsidiary was primarily hydrocarbon exploration and production.

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20. Interests in joint operations

Significant joint operations of BHP Petroleum are those with the most significant contributions to its net profit or net assets. BHP Petroleum's interest in the significant joint operations, whose principal activities are primarily hydrocarbon production, results are listed in the table below.

Significant joint operations	Country of operation	Principal activity	**2021 %**	2020 %	2019 %
Atlantis	US	Hydrocarbon production	**44**	44	44
Bass Strait	Australia	Hydrocarbon production	**50**	50	50
Macedon [(1)]	Australia	Hydrocarbon production	**71**	71	71
Mad Dog	US	Hydrocarbon production	**24**	24	24
North West Shelf	Australia	Hydrocarbon production	**12.5-16.67**	12.5-16.67	12.5-16.67
Pyrenees [(1)]	Australia	Hydrocarbon production	**40-71.43**	40-71.43	40-71.43
ROD Integrated Development [(2)]	Algeria	Hydrocarbon production	**29**	30	30
Shenzi [(3)]	US	Hydrocarbon production	**72**	44	44
Trinidad and Tobago [(1)(4)]	Trinidad and Tobago	Hydrocarbon production	**45-68.46**	45-68.46	45-68.46

(1) While BHP Petroleum may hold a greater than 50 per cent interest in these joint operations, all the participants in these joint operations approve the operating and capital budgets and therefore BHP Petroleum has joint control over the relevant activities of these arrangements.

(2) BHP Petroleum's interest reflects the working interest and may vary year-on-year based on BHP Petroleum's effective interest in producing wells.

(3) Relates to BHP Petroleum's acquisition of an additional 28 per cent working interest in Shenzi.

(4) Trinidad and Tobago joint operations include Greater Angostura and Ruby.

Shenzi Acquisition

In November 2020, BHP Petroleum finalised a membership interest purchase and sale agreement to acquire an additional 28 per cent working interest in Shenzi. The transaction was completed on 6 November 2020 for a purchase price of US$480 million after customary post-closing adjustments. Shenzi continues to be accounted for as a joint operation because BHP Petroleum continues to have joint decision-making rights with the other joint venture partner.

The assets and liabilities related to the acquired interests have been accounted for in line with the principles of IFRS 3 'Business Combinations' with no remeasurement of BHP Petroleum's previous interest. The acquisition resulted in increases to property, plant and equipment of US$642 million, inventory of US$17 million and closure and rehabilitation liabilities of US$179 million. Fair value of the identifiable assets and liabilities approximate the consideration paid and therefore no goodwill or bargain purchase gain has been recognised for the acquisition. The acquisition of an additional 28 per cent working interest in Shenzi since November 2020 contributed US$136 million of revenue and US$48 million to profit before tax of BHP Petroleum in FY2021. If the acquisition had taken place at the beginning of the financial year, revenue for BHP Petroleum would have been US$3,952 million and loss before tax for BHP Petroleum would have been US$183 million.

BHP Petroleum's share of assets held in joint operations subject to significant restrictions are as follows:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Current assets	**866**	804	751
Non-current assets	**12,255**	11,516	10,943
Total assets [(1)]	**13,121**	12,320	11,694

(1) While BHP Petroleum is unrestricted in its ability to sell a share of its interest in these joint operations, it does not have the right to sell individual assets that are used in these joint operations without the unanimous consent of the other participants. The assets in these joint operations are also restricted to the extent that they are only available to be used by the joint operation itself and not by other operations of BHP Petroleum.

21. Investments in associates

Ownership interest for BHP Petroleum's investments in associates, which are operated in the US, are listed in the table below:

Associates	**Principal activity**	**Reporting date**	**Ownership interest %** [(1)]
Caesar Oil Pipeline Company LLC (COP)	Hydrocarbons transportation	31 December	25
Cleopatra Gas Gathering Company LLC (CGG)	Hydrocarbons transportation	31 December	22
Marine Well Containment Company LLC (MWCC)	Oil spill services	31 December	10

(1) Reflects BHP Petroleum's ownership interest at 30 June 2021, 2020 and 2019.

BHP Petroleum is restricted in its ability to make dividend payments from its investments in associates as any such payments require the approval of all investors in the associates. There has been no change in BHP Petroleum's ownership interest in the associates for any of the reporting periods covered by these combined financial statements. When the annual financial reporting date is different to BHP Petroleum's, financial information is obtained as at 30 June in order to report on an annual basis consistent with BHP Petroleum's reporting date.

The movement for the year in BHP Petroleum's net investments in associates is as follows:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
At the beginning of the financial year	**245**	239	249
Loss from investments in associates	**(6)**	(4)	(2)
Investment in associates	**25**	22	6
Dividends received from associates	**(11)**	(12)	(14)
At the end of the financial year	**253**	245	239

The following table summarises the financial information relating to each of BHP Petroleum's significant equity accounted investments:

	COP			CGG			MWCC		
			Unaudited			*Unaudited*			*Unaudited*
	2021 US$'000	2020 US$'000	2019 US$'000	**2021 US$'000**	2020 US$'000	2019 US$'000	**2021 US$'000**	2020 US$'000	2019 US$'000
Current assets	**7,873**	10,090	8,758	**7,102**	6,414	6,076	**25,145**	22,147	16,935
Non-current assets	**199,335**	202,082	212,006	**206,496**	211,909	223,265	**1,565,938**	1,619,219	1,545,412
Current liabilities	**(1,262)**	(2,344)	(479)	**(198)**	(174)	(187)	**(14,414)**	(16,938)	(28,992)
Non-current liabilities	**-**	-	(7,512)	**-**	-	(5,944)	**(273,446)**	(262,143)	(153,890)
Net Assets	**205,946**	209,828	212,773	**213,400**	218,149	223,210	**1,303,223**	1,362,285	1,379,465
Net assets – Company share	51,486	52,457	53,193	46,948	47,993	49,106	130,322	136,229	137,947
Adjustments for difference between US GAAP and IFRS	(1,493)	(536)	(252)	(1,046)	(286)	(117)	26,748	9,536	(1,049)
Carrying amount of investment	**49,993**	51,921	52,941	**45,902**	47,707	48,989	**157,070**	145,765	136,898
Revenue – 100%	**36,028**	40,988	46,897	**18,048**	21,178	25,827	**41,042**	54,204	63,441
Profit/(loss) – 100%	**22,691**	28,288	35,264	**6,694**	12,271	22,028	**(135,877)**	(135,600)	(154,883)
Profit/(loss) – Company share	**5,673**	7,072	8,816	**1,473**	2,700	4,846	**(13,588)**	(13,560)	(15,488)
Dividends received	**7,600**	8,093	8,950	**3,278**	3,982	4,906	**-**	-	-
Contributions	**-**	-	-	**-**	-	-	**24,893**	22,427	5,382

22. Related party transactions

BHP Petroleum has a related party relationship with key management personnel, equity accounted investments (see Note 21 'Investments in associates') and entities under common control of BHP Group.

Transactions with key management personnel

Key management personnel includes roles which have the authority and responsibility for planning, directing and controlling the activities of BHP Petroleum. The compensation for key management personnel for the years ended 30 June 2021, 2020 and 2019 are as follows:

	2021 US$	2020 US$	*Unaudited* 2019 US$
Short-term employee benefits	**6,679,429**	8,526,547	10,086,495
Post-employment benefits	**701,596**	1,009,198	1,116,154
Share-based payments	**2,492,766**	3,511,720	4,259,619
Total	**9,873,791**	13,047,465	15,462,268

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Transactions with equity accounted investments

The following transactions took place during the year with equity accounted investments:

	2021 US$M	2020 US$M	*Unaudited* 2019 US$M
Purchases of goods/services	**16**	20	23
Dividends received	**11**	12	14

Outstanding balances with related parties

	Equity Accounted Investments			BHP Group Entities		
	2021 US$M	2020 US$M	*Unaudited* 2019 US$M	**2021 US$M**	2020 US$M	*Unaudited* 2019 US$M
Amounts payable to BHP Group	**-**	-	-	**12,348**	16,880	20,860
Trade amounts owing from related parties	**2**	1	2	**-**	-	-
Amounts receivable from BHP Group	**-**	-	-	**5,526**	12,424	15,871

BHP Petroleum has a financing arrangement with BHP Group for short-term cash management. As at 30 June 2021 amount receivable from BHP Group related to these financing arrangements was US$5,526 million (2020: US$12,424 million, 2019: US$ 15,871 million). These amounts are included in receivables from BHP Group on the balance sheet. As at 30 June 2021 amounts payable to BHP Group related to this was US$2,001 million (2020: US$2,540 million, 2019: US$3,520 million).

BHP Petroleum also entered into long-term debt agreements with BHP Group to finance its projects. The current portion of the long-term debt is recorded on the balance sheet under current liabilities in Payables to BHP Group. The current portion of long-term debt as at 30 June 2021 was $0 (2020: US$3,993 million, 2019: US$3,000 million). The non-current portion of the long-term debt is recorded on the balance sheet under non-current liabilities in Payables to BHP Group. The non-current portion of long-term debt as at 30 June 2021 was US$ 10,347 million (2020: US$ 10,347 million, 2019: US$ 14,340 million). Interest expense related to the long-term debt is recorded in Finance expense in the income statement. Interest expense related to the long-term debt for the year ended 30 June 2021 was US$267 million (2020:US$622 million, 2019:US$822 million). The long-term debt agreements with BHP Group are entered at 3-month USD LIBOR plus margin. The margin ranges between 1.3 per cent and 1.8 per cent. The long-term debt agreements have a maturity date between November 2022 and December 2022.

There are no expected credit losses related to balances from related parties at 30 June 2021, 2020 and 2019.

BHP Petroleum has entered various performance and corporate guarantees with certain BHP Group entities in the normal course of business. At 30 June 2021, BHP Petroleum had outstanding guarantees as follows:

Guarantees provided by BHP Petroleum:

- corporate guarantee given to financial institutions that manage future trades in order to hedge oil and gas production with maximum exposure of US$1 million

Guarantees received by BHP Petroleum:

- corporate guarantee received for regulatory requirements for drilling in the amount of US$20 million

- corporate guarantee received for exploration licenses in the amount of US$232 million
- corporate guarantee received for Outer Continental Shelf Right of Way Grade Bond in the amount of US$3.3 million
- corporate guarantee received for plugging and abandonment of well in the amount of US$12 million

The likelihood of these performance and corporate guarantees being called upon is considered remote.

23. Significant entities of BHP Petroleum

As disclosed in Note 1 'Organisation and summary of significant accounting policies' the combined financial statements include financial information that is limited to the legal entities carved out from BHP Group Limited. A listing of subsidiaries of BHP Petroleum, included as part of the Proposed Transaction boundary are detailed below. For subsidiaries and joint operations that most significantly contribute to BHP Petroleum's net profit and net assets refer to Note 19 'Subsidiaries', Note 20 'Interest in joint operations'.

Wholly owned subsidiaries

Country of Incorporation
Australia
Registered office address
125 St Georges Terrace, Perth, WA 6000, Australia
Company Name
BHP Billiton Petroleum Holdings LLC
BHP Petroleum (Australia) Pty Ltd
BHP Petroleum (Bass Strait) Pty Ltd
BHP Petroleum (International Exploration) Pty Ltd
BHP Petroleum (North West Shelf) Pty Ltd
BHP Petroleum Investments (Great Britain) Pty Ltd
BHP Petroleum Pty Ltd

Bermuda
Victoria Place, 31 Victoria Street, Hamilton, HM 10, Bermuda
BHP Petroleum (Tankers) Limited

Canada
4500 Bankers Hall East, 855-2nd Street S.W., Calgary, Alberta, T2P 4K7, Canada
BHP Billiton (Trinidad-2C) Ltd.

Canada
1741 Lower Water Street, Suite 600, Halifax NS B3J 0J2, Canada
BHP Petroleum (New Ventures) Corporation

Saint Lucia
Pointe Seraphine, Castries, St Lucia
BHP (Trinidad) Holdings Ltd.

Trinidad
Invaders Bay Tower, Invaders Bay, off Audrey Jeffers Highway, Port of Spain, Trinidad, Trinidad and Tobago
BHP (Trinidad-3A) Ltd

United Kingdom
Nova South, 160 Victoria Street, London, England, SW1E 5LB, United Kingdom
BHP Petroleum (Trinidad Block 23A) Limited
BHP Petroleum (Trinidad Block 28) Limited
BHP Petroleum (Mexico) Limited
BHP Petroleum (Carlisle Bay)
BHP Petroleum (Egypt) Limited
BHP Billiton Petroleum Limited

United States
Suite B, 1675 South State Street, Dover, DE, 19901, United States of America
BHP Billiton Petroleum Holdings LLC
BHP Resources Inc.
BHP Billiton Petroleum (Americas) Inc.
BHP Billiton Petroleum (GOM) Inc.
Hamilton Brothers Petroleum Corporation
Hamilton Oil Company Inc.
BHP Billiton Bolivianna de Petroleo Inc.
BHP Petroleum (Arkansas Holdings) LLC
BHP Petroleum (Foreign Exploration Holdings) LLC
BHP Petroleum (North America) LLC
BHP Holdings (Resources) Inc
BHP Billiton Marketing Inc.
Broken Hill Proprietary (USA) Inc
BHP Billiton Petroleum (Deepwater) Inc.
BHP Petroleum (Mexico Holdings) LLC
BHP Petroleum (Trinidad Block 3) Limited
BHP Petroleum (Trinidad Block 6) Limited
BHP Petroleum (Trinidad Block 14) Limited
BHP Billiton Petroleum (Trinidad Block 23B) Limited
BHP Petroleum (Trinidad Block 29) Limited
BHP Billiton Petroleum (South Africa 3B/4B) Limited
BHP Petroleum (Trinidad Block 5) Limited
BHP Billiton Petroleum (Trinidad Block 7) Limited

United States
1188 Bishop Street, Suite 2212, Honolulu, HI 96813, United States of America
BHP Hawaii Inc.

Subsidiaries where effective interest is less than 100%

Country of Incorporation
Brazil
Registered office address
Avenida Rio Branco, No. 110, room 901, Centro, Rio de Janeiro, 20040-001, Brazil
Company Name
BHP Billiton Brasil Investimentos de Petróleo Ltda.
BHP Billiton Brasil Exploração e Produção de Petróleo Limitada

Mexico
Av. Ejercito Nacional #769, Torre B, Piso 3, Colonia Granada, Alcadia Miguel Hidalgo, Ciudad de Mexico, 11520, Mexico
Perdido Mexico Pipeline Holdings, S.A. de C.V.
Perdido Mexico Pipeline, S. de R.L. de C.V.
BHP Billiton Petróleo Holdings de México, S. de R.L. de C.V.
BHP Billiton Petróleo Servicios Administrativos, S. de R.L. de C.V.
Operaciones Conjuntas, S. de R.L. de C.V.
BHP Billiton Petróleo Servicios de México, S. de R.L. de C.V.
BHP Billiton Petróleo Operaciones de México, S. de R.L. de C.V.

United States
Suite B, 1675 South State Street, Dover, DE, 19901, United States of America
BHP Billiton Petroleum Holdings (USA) Inc.

Joint Operations

Australia
Registered office address
Level 16, Alluvion Building, 58 Mounts Bay Road, Perth, WA 6000, Australia
Company Name
North West Shelf Liaison Company Pty Ltd
North West Shelf Shipping Service Company Pty Ltd
North West Shelf Gas Pty Limited
North West Shelf Lifting Coordinator Pty Ltd
China Administration Company Pty Ltd

Associates

United States
Registered office address
1209 Orange Street, Wilmington, DE, 19801, United States of America
Company Name
Caesar Oil Pipeline Company LLC
Cleopatra Gas Gathering Company LLC

United States
9807 Katy Freeway, Suite 1200, Houston, TX, 77024, United States of America
Marine Well Containment Company LLC

24. Discontinued operations (Onshore US assets)

On 28 September 2018, BHP Petroleum completed the sale of 100 per cent of the issued share capital of BHP Billiton Petroleum (Arkansas) Inc. and 100 per cent of the membership interests in BHP Billiton Petroleum (Fayetteville) LLC, which held the Fayetteville assets, for a gross cash consideration of US$0.3 billion.

On 31 October 2018, BHP Petroleum completed the sale of 100 per cent of the issued share capital of Petrohawk Energy Corporation, the subsidiary which held the Eagle Ford (being Black Hawk and Hawkville), Haynesville and Permian assets, for a gross cash consideration of US$10.3 billion (net of preliminary customary completion adjustments of US$0.2 billion). Results from the Onshore US assets are disclosed as Discontinued operations.

BHP Petroleum Assets

Notes to the Financial Statements

While the effective date at which the right to economic profits transferred to the purchasers was 1 July 2018, BHP Petroleum continued to control the Onshore US assets until the completion dates of their respective transactions. As such BHP Petroleum continued to recognise its share of revenue, expenses, net finance costs and associated income tax expense related to the operation until the completion date. In addition, BHP Petroleum provided transitional services to the buyer, which ceased in July 2019.

The completion adjustments included a reduction in sale proceeds, based on the operating cash generated and retained by BHP Petroleum in the period prior to completion, in order to transfer the economic profits from 1 July 2018 to completion date to the buyers. Therefore, the pre-tax profit from operating the assets is largely offset by a pre-tax loss on disposal. Accordingly, the net loss from discontinued operations predominantly relates to incremental costs arising as a consequence of the divestment, including restructuring costs and provisions for surplus office accommodation and tax expenses largely triggered by the completion of the transactions.

The contribution of Discontinued operations included within BHP Petroleum's profit and cash flows are detailed below:

Income statement – Discontinued operations

	Unaudited 2019 US$M
Revenue	851
Other income	94
Expenses excluding net finance costs	(729)
Profit/(loss) from operations	216
Financial expenses	(8)
Net finance costs	(8)
Profit/(loss) before taxation	208
Income tax (expense)/benefit	(33)
Profit/(loss) after taxation from operating activities	175
Net loss on disposal	(510)
Loss after taxation	(335)
Attributable to non-controlling interests	7
Attributable to BHP Petroleum	(342)

The total comprehensive income attributable to BHP Petroleum from Discontinued operations was a loss of US$342 million in 2019.

Cash flows from Discontinued operations

	Unaudited 2019 US$M
Net operating cash flows	474
Net investing cash flows (1)	(443)
Net financing cash flows (2)	(13)
Net increase/(decrease) in cash and cash equivalents from Discontinued operations	18
Net proceeds received from the sale of Onshore US	10,531
Less Cash and cash equivalents	(104)

Proceeds from divestment of Onshore US, net of its cash	10,427
Total cash impact	10,445

(1) Includes purchases of property, plant and equipment of US$443 million.
(2) Includes net repayment of interest bearing liabilities of US$6 million and dividends paid to non-controlling interests of US$7 million.

Net loss on disposal of Discontinued operations

Details of the net loss on disposal is presented below:

	Unaudited 2019 US$M
Assets	
Cash and cash equivalents	104
Trade and other receivables	562
Other financial assets	31
Inventories	34
Property, plant and equipment	10,998
Intangible assets	667
Total assets	12,396
Liabilities	
Trade and other payables	794
Provisions	491
Total liabilities	1,285
Net assets	11,111
Less non-controlling interest share of net assets disposed	(168)
BHP Petroleum's of net assets disposed	10,943
Gross consideration	10,555
Less transaction costs	(54)
Income tax expense	(68)
Net loss on disposal	(510)

25. New and amended accounting standards and interpretations

BHP Petroleum adopted IFRS 16 'Leases' (IFRS 16) in BHP Petroleum's Financial Statements from 1 July 2019. The adoption of other new or amended accounting standards or interpretations applicable from 1 July 2019, including IFRIC 23 'Uncertainty over Income Tax Treatment', did not have a significant impact on BHP Petroleum's Financial Statements.

BHP Petroleum has also early adopted amendments to IFRS 9 'Financial Instruments' (IFRS 9) and IFRS 7 'Financial Instruments: Disclosures' (IFRS 7) in relation to Interest Rate Benchmark Reform.

IFRS 16 Leases

IFRS 16 replaces IAS 17 'Leases' (IAS 17) including associated interpretative guidance and covers the recognition, measurement, presentation and disclosures of leases in the Financial Statements of both lessees and lessors.

Transition impact

IFRS 16 became effective for BHP Petroleum from 1 July 2019 and BHP Petroleum elected to apply the modified retrospective transition approach, with no restatement of comparative financial information. For existing finance leases, the right-of-use asset and lease liability on transition was the IAS 17 carrying amounts as at 30 June 2019. BHP Petroleum did not recognise any finance leases as at 30 June 2019.

As allowed by IFRS 16, BHP Petroleum has elected:

- except for existing finance leases, to measure the right-of-use asset on transition at an amount equal to the lease liability (as adjusted for prepaid or accrued lease payments);
- not to recognise low-value or short-term leases on the balance sheet;
- to only recognise, within the lease liability, the lease component of contracts that include non-lease components and other services;
- to adjust the carrying amount of right-of-use assets on transition for related onerous lease provisions that were recognised on BHP Petroleum's balance sheet as at 30 June 2019.

Adoption of IFRS 16 resulted in an increase in interest bearing liabilities of US$438 million, right-of-use assets of US$361 million and net adjustments to other assets and liabilities of US$36 million at 1 July 2019. The weighted average incremental borrowing rate applied to BHP Petroleum's additional lease liabilities at 1 July 2019 was 2.3 per cent taking into account the currency, tenor and location of each lease.

The following table provides a reconciliation of the operating lease commitments disclosed as at 30 June 2019 the total lease liability recognised at 1 July 2019:

	Unaudited US$M
Operating lease commitments as at 30 June 2019	402
Add: Leases which did not meet the definition of a lease under IAS 17	1
Add: Cost of reasonably certain extension options (discounted)	91
Less: Components excluded from lease liability (undiscounted)	(5)
Less: Effect of discounting	(51)
Total additional lease liabilities recognised at 1 July 2019	**438**

BHP Petroleum's activities as a lessor are not material and hence there is no significant impact on the Financial Statements on adoption of IFRS 16.

26. Subsequent events

In November 2021, BHP Group Limited (BHP) and Woodside Petroleum Ltd (Woodside) signed a binding share sale agreement for the merger of BHP's oil and gas portfolio with Woodside. Woodside will acquire the entire share capital of BHP Petroleum International Pty Ltd in exchange for new Woodside shares. The merger is expected to be completed during the first half of calendar year 2022.

In November 2021, the BHP Group approved US$1.5 billion in capital expenditure for development of the Scarborough upstream project located in the North Carnarvon Basin, Western Australia. A final investment decision has also been made by Woodside which has triggered a US$150 million payment to BHP Petroleum (North West Shelf) Pty Ltd (a wholly owned subsidiary of BHP Petroleum) by Woodside, in accordance with the terms of the 2016 divestment of BHP's 25 per cent Scarborough Joint Venture interest to Woodside.

The approved capital expenditure represents BHP's 26.5 per cent participating interest in Phase 1 of the upstream development. Woodside holds the remaining 73.5 per cent interest and is the operator of the project.

Other than the matters outlined above, no matters or circumstances have arisen since the end of the financial year that have significantly affected, or may significantly affect, the operations, results of operations or state of affairs in subsequent accounting periods of BHP Petroleum.

1. Supplementary oil and gas information – unaudited

In accordance with the requirements of the Financial Accounting Standards Board (FASB) Accounting Standard Codification 'Extractive Activities-Oil and Gas' (Topic 932) and SEC requirements set out in Subpart 1200 of Regulation S-K, BHP Petroleum is presenting certain disclosures about its oil and gas activities. These disclosures are presented below as supplementary oil and gas information, in addition to information relating to the reserves and production of BHP Petroleum disclosed in the registration statement to which these financial statements are attached.

The information set out in this section is referred to as unaudited as it is not included in the scope of the audit opinion of the independent auditor on BHP Petroleum's combined financial statements.

Reserves and production

Proved oil and gas reserves and net crude oil and condensate, natural gas, LNG and NGL production information for BHP Petroleum is included in the registration statement to which these financial statements are attached.

Capitalised costs relating to oil and gas production activities

The following table shows the aggregate capitalised costs relating to oil and gas exploration and production activities and related accumulated depreciation, depletion, amortisation and valuation provisions.

	Australia US$M	United States US$M	Other(1) US$M	Total US$M
Capitalised cost				
2021				
Unproved properties	**–**	**754**	**580**	**1,334**
Proved properties	**17,882**	**13,210**	**1,972**	**33,064**
Total costs	**17,882**	**13,964**	**2,552**	**34,398**
Less: Accumulated depreciation, depletion, amortisation and valuation provisions	**(12,720)**	**(8,329)**	**(1,483)**	**(22,532)**
Net capitalised costs	**5,162**	**5,635**	**1,069**	**11,866**
2020				
Unproved properties	10	808	576	1,394
Proved properties	17,079	12,538	1,743	31,360
Total costs	17,089	13,346	2,319	32,754
Less: Accumulated depreciation, depletion, amortisation and valuation provisions	(11,423)	(8,726)	(1,370)	(21,519)
Net capitalised costs	5,666	4,620	949	11,235
2019				
Unproved properties	10	875	458	1,343
Proved properties	16,514	11,751	1,625	29,890
Total costs	16,524	12,626	2,083	31,233
Less: Accumulated depreciation, depletion, amortisation and valuation provisions	(10,867)	(8,339)	(1,302)	(20,508)
Net capitalised costs	5,657	4,287	781	10,725

(1) Other is primarily comprised of Algeria, Mexico, and Trinidad and Tobago.

Costs incurred relating to oil and gas property acquisition, exploration and development activities

The following table shows costs incurred relating to oil and gas property acquisition, exploration and development activities (whether charged to expense or capitalised). Amounts shown include interest capitalised.

	Australia US$M	United States(3) US$M	Other(4) US$M	Total US$M
2021				
Acquisitions of proved property	**–**	**642**	**–**	**642**
Acquisitions of unproved property	**–**	**19**	**–**	**19**
Exploration(1)	**23**	**166**	**310**	**499**
Development	**201**	**749**	**184**	**1,134**
Total costs(2)	**224**	**1,576**	**494**	**2,294**
2020				
Acquisitions of proved property	–	–	–	–
Acquisitions of unproved property	–	38	6	44
Exploration(1)	38	278	370	686
Development	232	676	100	1,008
Total costs(2)	270	992	476	1,738
2019				
Acquisitions of proved property	–	–	–	–
Acquisitions of unproved property	–	5	–	5
Exploration(1)	44	190	492	726
Development	132	792	54	978
Total costs(2)	176	987	546	1,709

(1) Represents gross exploration expenditure, including capitalised exploration expenditure, geological and geophysical expenditure and development evaluation costs charged to income as incurred.

(2) Total costs include US$1,160 million (2020: US$1,178 million; 2019: US$1,275 million) capitalised during the year.

(3) Total costs include Onshore US assets of US$ nil (2020: US$ nil; 2019: US$331 million).

(4) Other is primarily comprised of Algeria, Canada, Mexico and Trinidad and Tobago.

Results of operations from oil and gas producing activities

Amounts shown in the following table exclude financial income, financial expenses, and general corporate overheads. Further, the amounts shown below include Onshore US.

Income taxes were determined by applying the applicable statutory rates to pre-tax income with adjustments for permanent differences and tax credits.

	Australia US$M	United States(7) US$M	Other(8) US$M	Total US$M
2021				
Oil and gas revenue(1)	**2,272**	**1,244**	**368**	**3,884**
Production costs	**(487)**	**(267)**	**(80)**	**(834)**
Exploration expenses	**(23)**	**(164)**	**(305)**	**(492)**
Depreciation, depletion, amortisation and valuation provision(2)	**(1,210)**	**(489)**	**(113)**	**(1,812)**
Production taxes(3)	**(125)**	**–**	**(12)**	**(137)**
	427	**324**	**(142)**	**609**
Accretion expense(4)	**(89)**	**(22)**	**(3)**	**(114)**
Income taxes	**(46)**	**(78)**	**(105)**	**(229)**
Royalty-related taxes(5)	**11**	**–**	**–**	**11**
Results of oil and gas producing activities(6)	**303**	**224**	**(250)**	**277**
2020				
Oil and gas revenue(1)	2,535	1,101	350	3,986
Production costs	(575)	(161)	(76)	(812)
Exploration expenses	(37)	(271)	(252)	(560)
Depreciation, depletion, amortisation and valuation provision(2)	(906)	(476)	(75)	(1,457)
Production taxes(3)	(177)	(1)	(13)	(191)
	840	192	(66)	966
Accretion expense(4)	(78)	(24)	(5)	(107)
Income taxes	(275)	(35)	(134)	(444)
Royalty-related taxes(5)	(85)	–	–	(85)
Results of oil and gas producing activities(6)	402	133	(205)	330
2019				
Oil and gas revenue(1)	3,404	2,675	598	6,677
Production costs	(752)	(568)	(110)	(1,430)
Exploration expenses	(44)	(162)	(229)	(435)
Depreciation, depletion, amortisation and valuation provision(2)	(917)	(621)	(103)	(1,641)
Production taxes(3)	(198)	–	(25)	(223)
	1,493	1,324	131	2,948
Accretion expense(4)	(80)	(34)	(8)	(122)
Income taxes	(530)	(193)	(236)	(959)
Royalty-related taxes(5)	(164)	–	–	(164)
Results of oil and gas producing activities(6)	719	1,097	(113)	1,703

(1) Includes sales to affiliated companies of US$51 million (2020: US$62 million; 2019: US$75 million).

(2) Includes valuation provision of US$101 million (2020: US$12 million; 2019: US$21 million).

(3) Includes royalties and excise duty.

(4) Represents the unwinding of the discount on the closure and rehabilitation provision.

(5) Includes petroleum resource rent tax and petroleum revenue tax where applicable.

(6) Amounts shown exclude financial income, financial expenses and general corporate overheads and, accordingly, do not represent all of the operations attributable to the Petroleum segment presented in note 1 'Segment reporting' in section 3.1.

(7) Results of oil and gas producing activities includes Onshore US assets of US$ nil (2020: US$ nil; 2019: US$431 million).

(8) Other is primarily comprised of Algeria, Canada, Mexico, and Trinidad and Tobago.

Standardised measure of discounted future net cash flows relating to proved oil and gas reserves (Standardised measure)

The following tables set out the standardised measure of discounted future net cash flows, and changes therein, related to BHP Petroleum's estimated proved reserves and should be read in conjunction with that related disclosure.
The analysis is prepared in compliance with FASB Oil and Gas Disclosure requirements, applying certain prescribed assumptions under Topic 932 including the use of unweighted

average first-day-of-the-month market prices for the previous 12-months, year-end cost factors, currently enacted tax rates and an annual discount factor of 10 per cent to year-end quantities of net proved reserves.

Certain key assumptions prescribed under Topic 932 are arbitrary in nature and may not prove to be accurate. The reserve estimates on which the Standard measure is based are subject to revision as further technical information becomes available or economic conditions change.

Discounted future net cash flows like those shown below are not intended to represent estimates of fair value. An estimate of fair value would also take into account, among other things, the expected recovery of reserves in excess of proved reserves, anticipated future changes in commodity prices, exchange rates, development and production costs as well as alternative discount factors representing the time value of money and adjustments for risk inherent in producing oil and gas.

	Australia US$M	United States US$M	Other(1) US$M	Total US$M
Standardised measure				
2021				
Future cash inflows	**8,948**	**13,437**	**1,561**	**23,946**
Future production costs	**(3,783)**	**(5,122)**	**(418)**	**(9,323)**
Future development costs	**(4,118)**	**(2,996)**	**(261)**	**(7,375)**
Future income taxes(2)	**706**	**(944)**	**(438)**	**(676)**
Future net cash flows	**1,753**	**4,375**	**444**	**6,572**
Discount at 10 per cent per annum	**(160)**	**(1,468)**	**(93)**	**(1,721)**
Standardised measure	**1,593**	**2,907**	**351**	**4,851**
2020				
Future cash inflows	11,526	12,997	1,660	26,183
Future production costs	(4,027)	(4,943)	(494)	(9,464)
Future development costs	(4,124)	(3,242)	(433)	(7,799)
Future income taxes(2)	(187)	(880)	(473)	(1,540)
Future net cash flows	3,188	3,932	260	7,380
Discount at 10 per cent per annum	(642)	(1,586)	(94)	(2,322)
Standardised measure	2,546	2,346	166	5,058
2019				
Future cash inflows	18,292	18,076	1,807	38,175
Future production costs	(4,710)	(4,917)	(459)	(10,086)
Future development costs	(3,860)	(4,516)	(226)	(8,602)
Future income taxes(2)	(2,551)	(1,657)	(711)	(4,919)
Future net cash flows	7,171	6,986	411	14,568
Discount at 10 per cent per annum	(1,926)	(3,396)	(94)	(5,416)
Standardised measure	5,245	3,590	317	9,152

(1) Other is primarily comprised of Algeria and Trinidad and Tobago.

(2) Future income taxes include credits to be received as a result of oil and gas operations and the utilisation of future tax losses by BHP Petroleum.

Changes in the Standardised measure are presented in the following table.

	2021 US$M	2020 US$M	2019 US$M
Changes in the Standardised measure			
Standardised measure at the beginning of the year	**5,058**	9,152	10,240
Revisions:			
Prices, net of production costs	**(175)**	(5,633)	3,821
Changes in future development costs	**(238)**	330	(228)

Revisions of reserves quantity estimates(1)	**(107)**	(229)	1,268
Accretion of discount	**678**	1,313	1,178
Changes in production timing and other	**360**	(310)	(618)
	5,576	4,623	15,661
Sales of oil and gas, net of production costs	**(2,901)**	(2,980)	(5,029)
Acquisitions of reserves-in-place	**462**	–	–
Sales of reserves-in-place(2)	**44**	–	(1,489)
Previously estimated development costs incurred	**1,075**	1,005	545
Extensions, discoveries, and improved recoveries, net of future costs	**17**	145	(33)
Changes in future income taxes	**578**	2,265	(503)
Standardised measure at the end of the year	**4,851**	5,058	9,152

(1) Changes in reserves quantities are shown in the Petroleum reserves tables in section 4.6.1.

(2) Onshore US assets disposal in 2019.

Accounting for suspended exploratory well costs

Refer to note 8 'Property, plant and equipment' in the financial statements for BHP Petroleum for a discussion of the accounting policy applied to the cost of exploratory wells. Suspended wells are also reviewed in this context.

The following table provides the changes to capitalised exploratory well costs that were pending the determination of proved reserves for the three years ended 30 June 2021, 30 June 2020 and 30 June 2019.

	2021 US$M	2020 US$M	2019 US$M
Movement in capitalised exploratory well costs			
At the beginning of the year	**1,089**	1,040	794
Additions to capitalised exploratory well costs pending the determination of proved reserves	**7**	120	297
Capitalised exploratory well costs charged to expense	**(66)**	–	(9)
Capitalised exploratory well costs reclassified to wells, equipment, and facilities based on the determination of proved reserves	–	(6)	(42)
Sale of suspended wells	–	(65)	–
At the end of the year	**1,030**	1,089	1,040

The following table provides an ageing of capitalised exploratory well costs, based on the date the drilling was completed, and the number of projects for which exploratory well costs has been capitalised for a period greater than one year since the completion of drilling.

Exploration activity typically involves drilling multiple wells, over a number of years, to fully evaluate and appraise a project. The term 'project' as used in this disclosure refers primarily to individual wells and associated exploratory activities.

	2021 US$M	2020 US$M	2019 US$M
Ageing of capitalised exploratory well costs			
Exploratory well costs capitalised for a period of one year or less	**7**	120	210
Exploratory well costs capitalised for a period greater than one year	**1,023**	969	830
At the end of the year	**1,030**	1,089	1,040

	2021	2020	2019
Number of projects that have been capitalised for a period greater than one year	**15**	14	13

Drilling and other exploratory and development activities

The number of crude oil and natural gas wells drilled and completed for each of the last three years was as follows:

	Net exploratory wells			Net development wells			
	Productive	Dry	Total	Productive	Dry	Total	Total
Year ended 30 June 2021							
Australia	**–**	**–**	**–**	**1**	**–**	**1**	**1**
United States(1)	**–**	**–**	**–**	**1**	**–**	**1**	**1**
Other(2)	**–**	**1**	**1**	**1**	**–**	**1**	**2**
Total	**–**	**1**	**1**	**3**	**–**	**3**	**4**
Year ended 30 June 2020							
Australia	–	–	–	–	–	–	–
United States(1)	–	–	–	–	1	1	1
Other(2)	1	1	2	1	–	1	3
Total	1	1	2	1	1	2	4
Year ended 30 June 2019							
Australia	–	–	–	1	–	1	1
United States(1)	1	–	1	33	–	33	34
Other(2)	4	2	6	–	–	–	6
Total	5	2	7	34	–	34	41

(1) Includes Onshore US assets net productive development wells of nil (2020: nil; 2019: 33). Includes Onshore US assets net exploratory wells of nil for 2021, 2020 and 2019.

(2) Other is primarily comprised of Algeria, Mexico and Trinidad and Tobago.

The number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. Completion refers to the installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

An exploratory well is a well drilled to find oil or gas in a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is a well drilled within the limits of a known oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

A productive well is an exploratory, development or extension well that is not a dry well. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well (hole) is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Oil and gas properties, wells, operations, and acreage

The following tables show the number of gross and net productive crude oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage as at 30 June 2021, 2020 and 2019. A gross well or acre is one in which a working interest is owned, while a net well or acre exists when the sum of fractional working interests owned in gross wells or acres equals one. Productive wells are producing wells and wells mechanically capable of production. Developed acreage is comprised of leased acres that are within an area by or assignable to a productive well. Undeveloped acreage is comprised of leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether such acres contain proved reserves.

The number of productive crude oil and natural gas wells in which BHP Petroleum held an interest at 30 June 2021 was as follows:

	Crude oil wells		Natural gas wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Australia	334	166	176	66	510	232
United States	55	27	–	–	55	27
Other(1)	61	23	8	4	69	27
Total	**450**	**216**	**184**	**70**	**634**	**286**

(1) Other is primarily comprised of Algeria and Trinidad and Tobago.

Of the productive crude oil and natural gas wells, 131 (net: 60) operated wells had multiple completions.

Developed and undeveloped acreage (including both leases and concessions) held at 30 June 2021 was as follows:

	Developed acreage		Undeveloped acreage	
Thousands of acres	Gross	Net	Gross	Net
Australia	2,423	897	391	148
United States	92	41	403	339
Other(1)(2)	160	67	3,394	3,104
Total	**2,675**	**1,005**	**4,188**	**3,591**

(1) Developed acreage in Other primarily consists of Algeria and Trinidad and Tobago.

(2) Undeveloped acreage in Other primarily consists of Barbados, Canada, Mexico and Trinidad and Tobago.

Approximately 139 thousand gross acres (22 thousand net acres), 386 thousand gross acres (241 thousand net acres) and 121 thousand gross acres (103 thousand net acres) of undeveloped acreage will expire in the years ending 30 June 2022, 2023 and 2024 respectively, if BHP Petroleum does not establish production or take any other action to extend the terms of the licences and concessions.

The number of productive crude oil and natural gas wells in which BHP Petroleum held an interest at 30 June 2020 was as follows:

	Crude oil wells		Natural gas wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Australia	353	176	162	54	515	230
United States	61	24	–	–	61	24
Other(1)	59	22	8	4	67	26
Total	**473**	**222**	**170**	**58**	**643**	**280**

(2) Other is primarily comprised of Algeria and Trinidad and Tobago.

Of the productive crude oil and natural gas wells, 133 (net: 62) operated wells had multiple completions.

Developed and undeveloped acreage (including both leases and concessions) held at 30 June 2020 was as follows:

Thousands of acres	Developed acreage		Undeveloped acreage	
	Gross	Net	Gross	Net
Australia	2,152	823	766	279
United States	98	36	844	800
Other(1)(2)	146	57	3,926	3,445
Total	**2,396**	**916**	**5,536**	**4,524**

(3) Developed acreage in Other primarily consists of Algeria and Trinidad and Tobago.

(4) Undeveloped acreage in Other primarily consists of Barbados, Canada, Mexico and Trinidad and Tobago.

Approximately 833 thousand gross acres (411 thousand net acres), 1,089 thousand gross acres (655 thousand net acres) and 264 thousand gross acres (256 thousand net acres) of undeveloped acreage will expire in the years ending 30 June 2021, 2022 and 2023 respectively, if BHP Petroleum does not establish production or take any other action to extend the terms of the licences and concessions.

The number of productive crude oil and natural gas wells in which BHP Petroleum held an interest at 30 June 2019 was as follows:

	Crude oil wells		Natural gas wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Australia	352	176	153	53	505	229
United States	60	25	–	–	60	25
Other(1)	57	21	8	4	65	25
Total	**469**	**222**	**161**	**57**	**630**	**279**

(3) Other is primarily comprised of Algeria, Mexico and Trinidad and Tobago.

Of the productive crude oil and natural gas wells, 43 (net: 18) operated wells had multiple completions.

Developed and undeveloped acreage (including both leases and concessions) held at 30 June 2019 was as follows:

Thousands of acres	Developed acreage		Undeveloped acreage	
	Gross	Net	Gross	Net
Australia	2,152	823	963	393
United States	105	39	828	776
Other(1)(2)	146	57	3,526	2,869
Total	**2,403**	**919**	**5,317**	**4,038**

(5) Developed acreage in Other primarily consists of Algeria and Trinidad and Tobago.

(6) Undeveloped acreage in Other primarily consists of Canada, Mexico and Trinidad and Tobago.

Approximately 126 thousand gross acres (59 thousand net acres), 1,612 thousand gross acres (932 thousand net acres) and 1,257 thousand gross acres (889 thousand net acres) of undeveloped acreage will expire in the years ending 30 June 2020, 2021 and 2022 respectively, if BHP Petroleum does not establish production or take any other action to extend the terms of the licences and concessions.

ANNEXURE 3 – COMPETENT PERSON REPORT

Gaffney Cline

Competent Person's Report on Certain Petroleum Assets of Woodside and BHP Petroleum

Prepared for

Woodside Petroleum Limited

23 March 2022

Gaffney Cline

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23 March 2022

Mr. Fayaz Jamal
Chief Reservoir Engineer/Reservoir Management
Woodside Petroleum Limited
11 Mount Street
Perth, WA 6000
Australia

Fayaz.Jamal@woodside.com.au

Dear Fayaz,

Competent Person's Report on Certain Petroleum Assets of Woodside and BHP Petroleum

Introduction

At the request of Woodside Petroleum Limited (Woodside), Gaffney, Cline & Associates Limited (GaffneyCline) has prepared this Competent Person's Report (CPR) on various assets of Woodside and BHP Petroleum International Pty Ltd (BHP Petroleum). Woodside's assets are located onshore and offshore Australia, offshore Myanmar, offshore Senegal, onshore British Columbia in Canada, Korea and Congo. BHP Petroleum's assets are located onshore and offshore Australia, in the United States and Mexican sectors of the Gulf of Mexico (GOM), offshore Trinidad and Tobago and onshore Canada [1].

Pursuant to the announcement on 17th August 2021 of the proposed all share merger of Woodside and BHP Petroleum, this CPR has been prepared for inclusion in a prospectus to be submitted to the Financial Conduct Authority (FCA) in connection with the admission of shares in the merged company to the official list of the FCA and to trading on the main market of the London Stock Exchange (LSE).

To comply with the requirements of the FCA, this CPR presents a statement of the Reserves, Contingent Resources and Prospective Resources of each company as at an effective date of 31st December 2021.

[1] BHP Petroleum also has assets in Algeria, but plans to divest them. These assets are not covered by this CPR as Woodside and BHP have agreed that BHP will retain the economic benefits thereof from the proposed Merger effective date, including the net proceeds from divestment. If the divestment has not completed prior to completion of the proposed Merger, Woodside will run the Algerian assets on behalf of BHP under an arrangement whereby BHP Petroleum will retain all economic exposure and indemnify Woodside for any costs and liabilities associated with Algeria until such time as both parties agree alternative arrangements or Algeria lapses (whichever is earlier).

In the preparation of this CPR, GaffneyCline has used the definitions of Reserves, Contingent Resources and Prospective Resources contained within 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 (see Appendix I).

The CPR is compliant with the Competent Person's Report requirements as published in the ESMA update of the Committee of European Securities Regulators' recommendations for the consistent implementation of the European Commission Regulation on Prospectuses No. 809/2004 dated 20th March 2013 (ESMA/2013/319).

Furthermore, for the purposes of UK Prospectus Regulation Rule 5.3.2R(2)(f), GaffneyCline accepts responsibility for the information contained in the CPR and confirms that, to the best of its knowledge, the information contained in the CPR is in accordance with the facts and makes no omission likely to affect its import.

In preparation of the CPR, Gaffney Cline relied upon, without independent verification, information furnished by, or on behalf of, Woodside with respect to the property interests being evaluated, production from such properties, current cost of operations and development, current prices for production, agreements related to current and future operations and sale of production, estimation of taxes, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of the CPR.

This CPR relates specifically and solely to the subject matter as defined in the scope of work, as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

A glossary of abbreviations is shown in Appendix II.

Executive Summary

Licence Summary

Table 1 lists the licences in which Woodside (a) and BHP Petroleum (b) hold working interests (WI) as at 31st December 2021. Reserves and Contingent Resources have been attributed to the majority of these licences. Other exploration licences are discussed in Sections 5 and 10.

Woodside and BHP Petroleum both have interests in the North West Shelf (NWS) gas and oil projects, and in the Scarborough LNG project (including the Jupiter and Thebe fields) in Australia, both operated by Woodside. Besides these two projects, Woodside and BHP Petroleum have no common assets.

Overview – Woodside Assets

The bulk of Woodside's assets are offshore Western Australia, largely linked to LNG projects, notably NWS, Pluto and Wheatstone. Woodside's non-Australian assets are in Myanmar, Senegal and Canada, of which the Sangomar development in Senegal, operated by Woodside, is the most significant. Woodside also has exploration acreage in Democratic Republic of Congo (Congo) and South Korea.

In production since 1984, the NWS development complex produces from multiple gas and oil fields covering 21 blocks located ~130 km offshore. Twelve gas fields have been developed (eight currently producing) with a combination of platforms and subsea wells and gas is exported from the offshore North Rankin Complex and Goodwyn Alpha Platform via two pipelines to the onshore Karratha Gas Plant for LNG and domestic gas use. A further field, Lambert Deep, is currently being developed, but production has recently started to decline. Additional potential exists to develop two satellite fields and four small discoveries, but these are currently regarded as sub-commercial. The NWS oil assets comprise three mature producing fields (Cossack, Wanaea and Hermes) and three undeveloped discoveries (Egret, Eaglehawk and West Dixon), though these are also considered sub-commercial.

The Brunello and Julimar Fields together form the Julimar Development Project, a subsea development to supply gas and condensate to the Wheatstone Project's onshore LNG trains and domestic gas plant at the Ashburton North Strategic Industrial Area via the Chevron-operated Wheatstone platform. Production from Brunello commenced in 2017 and the Julimar field came on stream in December 2021. Further development phases are anticipated.

Also offshore Western Australia, Woodside has interests in an exploitation permit supplying gas from subsea wells via a minimum facilities platform located in shallow water to the Pluto LNG plant, located close to the Karratha Gas Plant. The Pluto and Xena fields are producing, and Pyxis came on stream in November 2021.

The Scarborough gas field and two satellite discoveries, Jupiter and Thebe, will be developed with subsea wells in some 1,400 m water depth, tied back to a semisubmersible floating production unit (FPU). Gas will be transported 430 km by pipeline to the onshore Pluto LNG plant at Karratha, where an additional 5 MTPA train will be constructed to process the Scarborough gas. A Final Investment Decision (FID) was taken in November 2021, with first cargo loading expected in 2026 from Scarborough, followed by the satellite fields in later phases.

Table 1: Summary of Licences as at 31st December 2021

(a) Woodside

Country	Licence Block	Field/ Development	Woodside WI	Final License Expiry
Australia	WA- 1-L to 6-L, 23-L, 24-L, 30-L, 52-L, 53-L, 56-L to 58-L, WA-7-R R4, WA-28-P R8	NWS Gas	15.78%	Extendable
	WA-9-L, WA-11-L, WA-16-L,	NWS Oil	33.33%	
	WA-34-L	Pluto LNG	90.00%	
	WA-49-L, WA-356-P R2, WA-536-P	Wheatstone LNG (Brunello & Julimar)	65.00%	
	WA-61-L, WA-62-L	Scarborough LNG	73.50%	
	WA-61-R, WA-63-R	Thebe & Jupiter backfill to Scarborough	50.00%	
	WA-93-R & WA-94-R	Ragnar & Toro	70.00%	
	WA-404-P	Remy, Martell, Martin, Noblige and Larsen Deep discoveries	100.00%	
	WA-28-L & WA-59-L	Gr. Enfield Oil and Vincent	60.00%	
	WA-28-R to WA-32-R, TR/5 and R2	Browse Basin (Torosa, Calliance and Brecknock)	30.60%	
	NT/RL2 & NT/RL4	Gr. Sunrise (incl. Troubadour)	35.00% for RL2, 26.67% for RL4	
Timor Leste	PSC JPDA 03-19 & 03-20		27.67%	Oct-2026 for 03-19, Nov-2026 for 03-20
Myanmar	Block A6		40.00% (25.00% post government back-in)	December 2022
Senegal	Sangomar Exploitation Licence	Sangomar	82.00%	December 2048, extensions possible.
	Evaluation Extension Area	Exploration & Appraisal	90.00%	October 2021: 3-year extension application submitted.
Canada	Liard	Liard	50.00%[3]	Multiple renewals

(b) BHP Petroleum

Country	Licence Block	Field/ Development	BHP Petroleum WI	Final License Expiry
Australia	WA- 1-L to 6-L, 23-L, 24-L, 30-L, 52-L, 53-L, 56-L to 58-L, WA-7-R R4, WA-28-P R8	NWS Gas	15.78%	Extendable
	WA-9-L, WA-11-L, WA-16-L,	NWS Oil	16.66%	
	Vic/ L1 to L11, L13 to L20, L25, RL1, RL4	Bass Strait – GBJV	50.00%	
	Vic/ 9 and L25	Bass Strait – KUJV	32.50%	
	WA-42-L	Macedon	71.43%	
	WA-42-L & WA-43-L	Pyrenees and Scafell	71.43% & 39.999%	
	WA-61-L & WA-62-L	Scarborough LNG	26.50%	
	WA-61-R & WA-63-R	Thebe + Jupiter backfill to Scarborough	50.00%	
US GOM	GC 608, 609, 610, 652, 653 and 654	Shenzi	72.00%	Extendable
	GC608 & GC609	Shenzi N.	72.00%	
	GC564 & GC520	Wildling	100.00%	
	GC699, 742, 743 & 744	Atlantis	44.00%	
	GC 738, 781, 782, 824, 825, 826, 868 and 869	Mad Dog	23.90%	
Trinidad & Tobago	2(c)	Greater Angostura	45.00%	April 2026, extension for 5 years until April 2031
	2(c) Howler		64.30%	
	3(a)		68.46%	April 2031
	23(a) & 14	Calypso	70.00%	
	TTDAA5	Magellan	65.00%	
Mexico	Trion Contractual Area	Trion	60.00%	March 2052, extensions possible until Dec 2067.

Notes:

1. Licences are easily extended in Australia and US GoM when production remains commercial.
2. Licences in Australia, US GOM, Mexico and Canada are subject to tax/royalty fiscal regimes, whereas those in Myanmar, Senegal, and Trinidad & Tobago are in the form of Production Sharing Contracts (PSC) or similar.
3. Woodside's WI in Liard is expected to increase to 94.9% once transfer of certain leases is completed.

Woodside also has interests in five undeveloped gas discoveries (Remy, Martell, Martin, Noblige and Larsen Deep) in the WA-404-P permit offshore Western Australia, approximately 100 km northwest of the Pluto Field in water depth of 1,500 m. The discoveries are being evaluated for possible subsea development utilising a floating production facility, tied back ~100 km to the Pluto trunkline, to supplement Pluto LNG in later life, but are currently considered sub-commercial.

Greater Enfield and Vincent comprise a collection of oil and gas fields located in the Exmouth sub-basin of the Northern Carnarvon Basin, offshore Western Australia, in production since 2008. The producing fields are tied back to the Ngujima-Yin FPSO located over the Vincent Field and currently produce approximately 30,000 bopd. There are five further discoveries in Greater Enfield, but with no immediate plans to develop them. Two gas discoveries, Ragnar and Toro, are located ~40 km from the Greater Enfield area, but are currently viewed as technically and commercially immature due to their small volumes and distance from infrastructure.

In the Browse Basin, offshore Western Australia, Woodside has interests in five licences containing three large undeveloped gas and condensate discoveries (Torosa, Calliance and Brecknock). The development concept is a subsea tie-back to two FPSOs, from where gas would be exported via pipeline to the North Rankin Complex where it would join the supply of gas from the North West Shelf (NWS) fields to the onshore Karratha Gas Plant. The estimated timing for first gas is 2030 (to fill ullage in the NWS facilities) but the commercial viability of the development remains uncertain.

Greater Sunrise comprises the Sunrise and Troubadour fields, located in northern Australian and Timor-Leste waters. The Governments of Australia and Timor-Leste and the Sunrise Joint Venture will enter a new production sharing contract which will replace the four current titles and negotiations are understood to be ongoing. The fields lie approximately 150 km southeast of Timor-Leste and 450 km north of Australia in an area where the water depth varies between 100 and 600 m. No development concept has yet been selected and the development status remains uncertain.

At the effective date of this CPR, Woodside had an interest in offshore Block A6 in the Rakhine Basin of Western Myanmar operated by TotalEnergies, containing two undeveloped gas discoveries. However, Woodside issued an ASX announcement in January 2022 that it had decided to withdraw from its interests in Myanmar.

In Senegal, Woodside has interests in the offshore Sangomar exploitation licence and an adjacent Evaluation Extension Area. Multiple oil and gas reservoirs have been intersected and appraised in the Sangomar field and it is currently under development, with the first production well drilled during 2021. The development comprises an FPSO with subsea wells and includes water injection for pressure maintenance and gas injection for gas disposal. Subsequent phases are contingent on the outcome of the first phase and could include intensive development of oil reservoirs and a gas export project. The Evaluation Extension Area contains the undeveloped FAN discovery and the SNE North Prospect.

Woodside has an interest in unconventional (shale) gas deposits of the Kotcho Formation in the Liard Basin onshore British Columbia, Canada. The Liard discovery was appraised with the intention of supplying feedstock to an envisaged LNG plant on the coast near Kitimat (the KLNG plant). However, the KLNG concept has been abandoned and the operator, Chevron, is also divesting from the upstream asset. Woodside is in the process of taking over most of

Chevron's upstream interest and is retaining its position in Liard to evaluate further market opportunities for the potentially large volume of gas, although currently there are no viable plans for exploitation.

Overview – BHP Petroleum Assets

BHP Petroleum has significant assets in Western Australia and south-eastern Australia, as well as in the Gulf of Mexico (US and Mexico), and Trinidad and Tobago. The NWS and Greater Scarborough assets in which BHP Petroleum and Woodside (operator) share interests, are covered in the preceding section.

Bass Strait comprises some 24 oil and gas fields in the Gippsland basin, offshore the south-eastern margin of Eastern Victoria, Australia. Production commenced in 1969 and current production is primarily gas with condensate and declining oil rates from maturing oil fields. Most fields were developed with steel jackets in shallow water and mono-tower platforms or subsea tiebacks and two large, concrete gravity-based platforms have also been installed. Oil and gas from nearly 300 wells is transported to onshore plants at Longford and Long Island in multiple gas and oil pipelines. Development planning for four further discoveries (North Turrum, Sweetlips, Wirrah and East Pilchard) is maturing, but not yet certain.

The Macedon dry gas field is located in the Exmouth sub-basin, about 40 km north of Exmouth in Western Australia in water depth of 160 to 190 m. It has been developed with four subsea wells and gas is produced to the onshore Macedon gas plant, through a 90 km pipeline. First gas production was in 2013 and future plans include a compression project and three infill wells.

Also in the Exmouth sub-basin of Western Australia, BHP Petroleum operates the Pyrenees subsea development of up to seven oil accumulations located immediately to the northwest of Macedon in 200 m water depth. Production commenced in 2010 and the oil is processed on the Pyrenees Venture FPSO, while gas is used as fuel. The development occurred in three phases and the fields are mature. Future plans include an infill dual lateral and water shut-off operation (Phase 4) and additional infill drilling (Phase 5).

BHP Petroleum also has an interest in the Scafell gas discovery within the existing Pyrenees field production licence. Development of Scafell is likely to be as a tie-back to the Macedon manifold and timing will depend on when the Macedon gas production comes off plateau or when there is an increase in WA domestic gas demand.

BHP Petroleum has interests in four developments in the Green Canyon area of the US Gulf of Mexico (GOM): Shenzi, Shenzi North together with Wildling, operated by BHP Petroleum; and Atlantis and Mad Dog, operated by BP.

The Shenzi oil field was discovered in 2002 in the GOM in ~1,340 m water depth. The reservoirs are deep at 6,700 to 8,530 mss. The field was initially developed in 2007 with two subsea wells and a manifold tied to the Marco Polo tension leg platform (TLP). The development was then expanded with the Shenzi TLP, four more subsea manifolds and multiple wells. A subsea multiphase pumping project sanctioned in 2021 is currently in execution with production expected to start in 2022. Future development opportunities include conversion of a well from production to water injection, a side-track of a production well and the drilling of an additional producer/injector pair.

The Shenzi North and Wildling oil discoveries made in 2015 and 2017 respectively are located directly north of Shenzi. The fields have been appraised and the development plan is a daisy chained tie-in of two subsea production wells in each field to existing Shenzi facilities. Shenzi North was sanctioned in the third quarter of 2021 and is in Execution phase as at end 2021, while the proposed Wildling development entered Definition phase in 2021. Understanding of reservoir performance under depletion drive will help to plan a possible later phase waterflood.

The Atlantis phased development comprises a semi-submersible facility with subsea wells in ~2,135 m of water. There are 29 producing wells and three water injection wells. Oil production commenced in 2007 and production rates have been maintained at approximately 100 Mbopd since 2014, when the second phase of development was completed. Phase 3 was sanctioned in 2019 and drilling commenced the same year. By September 2021, five of the eight Phase 3 wells had been drilled, with three being completed and put online and two requiring sidetracks. Phase 3 drilling is expected to be completed in early 2023. Beyond Phase 3, continuous drilling is assumed until 2029 to bring online 12 additional producers and six water injectors. Despite the field having been in production for more than 14 years, much potential remains and there are several possible future projects, including one or two new water injectors and a side-track in the short term, expansion of Drill Centres 1, 2 and 3 with three, four and four new infill wells respectively and facilities expansion to incorporate subsea multiphase pumps.

The Mad Dog oil field was discovered in 1998 in water depth of 1,340 m. First production occurred in January 2005 and there are ten producing wells. The Mad Dog facility comprises a 16-slot, dry-tree, floating spar hull with integrated production and drilling capability. The facility will reach the end of its original design life late in 2024 and BP has undertaken studies to extend the life nominally to 2045. Oil and sales gas are exported through the Caesar and Cleopatra export pipeline systems in which BHP Petroleum has equity of 25% and 22% respectively. Phase 2 of the development has commenced and is scheduled to start contributing to production in 2022. Future projects will likely include implementation of water injection in the north and west, development of the southwest and infill drilling to supplement Phase 2 wells. Further potential might be realised by extending the A-spar life beyond 2045.

In Trinidad and Tobago, BHP Petroleum operates assets in three clusters: Shallow Water (the Greater Angostura Complex), Deep Water North (the Calypso Development) and Deep Water South (Magellan).

The Greater Angostura Complex, in production since 2005, includes producing oil and gas fields (AP3, Aripo, Horst, Kairi and Canteen) and discoveries (Howler and Canteen North). Additionally, the Ruby (oil and gas) and Delaware (gas) fields came on stream in 2021. Potential future plans include development of the Canteen North and Howler discoveries, lowering abandonment pressure in the Canteen, Kairi, Horst and Aripo fields and developed gas discovered in the Nariva age sands.

The Calypso Development area encompasses five gas discoveries (Bongos, Bele, Tuk, Hi-Hat, Boom) in water depth of ~2,000 m, resulting from the drilling of seven exploration wells. Several undrilled prospects in fault blocks immediately adjacent to discoveries remain to be tested in further appraisal. These are strongly supported by seismic attributes, and have high geological chance of success. Development initially appears likely to target parts of the Bongos, Bele and Tuk discoveries, including some of the undrilled fault blocks, but the development concept is still under study.

The Magellan asset comprises two dry gas discoveries (LeClerc and Victoria) in water depth of 1,800 m. A third exploration well was not successful. The total volume of gas discovered is not currently considered large enough to support a commercial standalone development

BHP Petroleum has an operated interest in the Trion oil field in the Mexican sector of the GOM, discovered in 2012 in ~2,500 m water depth. The field was appraised with three wells after the discovery well, two of which have a single side-track each, resulting in a total of six reservoir penetrations. Seismic data has been pivotal in delineating the field and identifying potential compartments. The crest of the structure is at ~3,800 mss, and the pressure is high (>6,400 psia). Plans are maturing to develop the field with subsea wells, likely comprising 14 production wells, ten water injection wells and three dual completed gas injection wells. It is currently envisaged that the wells will be tied back to a floating production unit (FPU) and stabilised crude will be sent to a floating storage and offloading facility (FSO) for export via tanker. Gas that is not re-injected will be exported for sales. First oil could be in 2026, though the development is not yet sanctioned. The northernmost fault-controlled segment of the field is considered undiscovered and is a low risk prospect.

Reserves Summary

Proved (1P) and Proved plus Probable (2P) Reserves net to each company are summarised in Table 2. The volumes reported as Reserves are sales quantities and exclude volumes of hydrocarbons consumed in operations as fuel (CiO). To facilitate comparison with the companies' annual reporting, CiO quantities are shown in Appendix III.

Table 2: Summary of Net Entitlement Reserves as at 31st December 2021

(a) Woodside Oil, Condensate and Gas

Country	Asset	Oil and Condensate Reserves (MMBbl)		Gas Reserves (Bscf)	
		Proved	Proved plus Probable	Proved	Proved plus Probable
Australia	North West Shelf	24.0	30.7	625	825
	Wheatstone LNG (Brunello & Julimar)	8.8	16.5	513	798
	Pluto LNG	19.5	24.3	1,448	1,801
	Scarborough LNG	-	-	4,762	7,429
	Greater Enfield	16.0	24.1	-	-
Senegal	Sangomar	100.6	148.1	-	-
Total		**168.9**	**243.7**	**7,349**	**10,854**

(b) Woodside NGL/LPG

Country	Asset / Project	NGL/LPG Reserves (MMBbl)	
		Proved	Proved plus Probable
Australia	North West Shelf	2.4	3.2
Total		**2.4**	**3.2**

(c) BHP Petroleum Oil, Condensate and Gas

Country	Asset	Oil and Condensate Reserves (MMBbl)		Gas Reserves (Bscf)	
		Proved	Proved plus Probable	Proved	Proved plus Probable
Australia	North West Shelf	19.2	24.9	603	795
	Bass Strait	10.6	17.9	344	600
	Macedon	-	-	223	278
	Pyrenees	10.0	19.0	-	-
	Scarborough LNG	-	-	1,717	2,679
US GOM	Shenzi	64.0	91.9	6	12
	Shenzi North	16.4	26.8	5	8
	Atlantis	59.4	153.9	22	42
	Mad Dog	129.2	180.0	12	20
Trinidad & Tobago	Angostura	1.6	1.9	159	219
	Ruby	1.4	1.8	24	33
Total		**311.9**	**518.0**	**3,116**	**4,685**

(d) BHP Petroleum NGL/LPG

Country	Asset / Project	NGL/LPG Reserves (MMBbl)	
		Proved	Proved plus Probable
Australia	North West Shelf	2.3	3.1
	Bass Strait	16.5	28.8
US GOM	Shenzi	1.7	3.1
	Shenzi North	1.1	1.7
	Atlantis	2.9	5.6
Total		**24.5**	**42.3**

Notes:

1. Reserves net to company are the company's net economic entitlement under the terms of the contract that governs each asset. For Australia and USA, this is equal to the company's working interest share of gross field Reserves less any royalty taken in kind. For Senegal and Trinidad & Tobago, it is equal to the company's share of Cost Recovery, Profit Oil and Tax Barrels (if any) under the terms of the relevant PSC.
2. GOM Reserves are net of Royalty although payments are in cash.
3. Totals may not exactly equal the sum of the individual entries due to rounding.
4. For Bass Straight and NWS, NGL composition is equivalent to LPG as they include only C3-C4 hydrocarbons. GOM NGL volumes represent C2-C5+ hydrocarbons
5. As recommended by PRMS, GaffneyCline does not include Consumed in Operation (CiO) volumes in Reserves; GaffneyCline reports only Sales volumes as Reserves.

Contingent Resources Summary

Contingent Resources net to each company are summarised in Table 3. The Contingent Resources are shown on a working interest (WI) basis, i.e. as the company's WI fraction of the gross field Contingent Resources. The WI basis volumes do not represent the company's actual net entitlement under the terms of the contract that governs the asset, which would be lower for PSCs or where royalty is deductible. The WI basis volumes are quoted here since many of the projects are not yet sufficiently mature to estimate the associated production profiles and costs that are needed to calculate the net entitlement.

Only the 2C (Best estimate) Contingent Resources are presented here.

Table 3: Summary of 2C Contingent Resources, as at 31st December 2021

(a) Net to Woodside (WI Basis)

Country	Asset / Project	2C Contingent Resources		Classification
		Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Australia	NWS Gas: facility upgrades, infill wells, workovers and new developments	0.3	12	Pending
		7.4	221	Unclarified
		1.9	53	Not Viable
	NWS Oil: facility upgrades, infill wells, workovers and new developments	7.2	3	Unclarified
		3.8	4	Not Viable
	Pluto turn-down rate reduction	0.6	53	Pending
	Pluto infill wells	2.7	231	Unclarified
	Brunello (Wheatstone LNG)	0.2	15	Unclarified
	Thebe and Jupiter (Greater Scarborough)	-	659	Pending
	WA-404-P (Remy, Martell, Martin, Noblige and Larsen Deep)	19.5	1,006	Not Viable
	Greater Enfield (incl. Vincent)	32.2	43	Not Viable
	Ragnar and Toro (WA-93-R & WA-94-R)	2.2	270	Not Viable
	Browse Basin (Torosa, Calliance and Brecknock)	119.3	4,469	On Hold
	Greater Sunrise	75.6	1,717	On Hold / Not Viable
Myanmar	Block A6	-	567	Not Viable
Senegal	Sangomar Phase 1 WI	22.1	-	Pending
	Sangomar Phases 2-5 + Gas export	214.0	301	Unclarified
	FAN discovery	81.0	-	Unclarified
Canada	Liard	-	13,350	Not Viable

Gaffney Cline

(b) Net to BHP Petroleum (WI Basis)

Country	Asset / Project	2C Contingent Resources		Classification
		Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Australia	NWS Gas: facility upgrades, infill wells, workovers and new developments	0.3	12	Pending
		7.4	221	Unclarified
		1.9	53	Not Viable
	NWS Oil: facility upgrades, infill wells, workovers and new developments	3.6	1	Unclarified
		1.9	2	Not Viable
	Bass Strait: N. Turrum, Sweetlips/Wirrah	16.3	118	Pending
	Bass Strait East Pilchard	1.8	20	Unclarified
	Macedon compression	-	41	Pending
	Macedon/Muiron infills	-	59	Unclarified
	Macedon Black Pearl tie-in	-	7	Not Viable
	Pyrenees Phase 4	3.2	-	Pending
	Pyrenees Phase 5	13.2	-	Unclarified
	Scafell	-	38	Not Viable
	Thebe and Jupiter (Greater Scarborough)	-	659	Pending
US GOM	Shenzi side-tracks & infills	25.0	7	Unclarified
	Wildling	36.9	11	Pending
	Atlantis SSMMP + WI + infills	66.9	28	Unclarified
	Atlantis expansions and infills	21.4	10	Not Viable
	Mad Dog WI expansion	15.9	-	Pending
	Mad Dog extensions and infills	54.3	4	Unclarified
Trinidad & Tobago	Angostura Block 2(c)	1.3	219	Not Viable
	Calypso	4.9	2,584	Unclarified
	Calypso	-	293	Not Viable
	Magellan	-	313	Not Viable
Mexico	Trion	256.8	79	Pending
	Trion post licence + gas blowdown	25.8	131	Unclarified

Table 3 Notes:

1. Net Contingent Resources in this table are Company's working interest fraction of the gross field Contingent Resources; they do not represent the Company's actual net entitlement under the terms of the contracts that govern the assets, which would be lower for PSCs or where royalty is deductible.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the asset may not be developed in the form envisaged or may not be developed at all (i.e., no "Chance of Development" (Pd) factor has been applied).
3. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
4. No deduction has been made for fuel, flare and shrinkage.
5. Note that on 27th January 2022 (after the effective date of this CPR), Woodside announced it was withdrawing from its interests in Myanmar.

A pro-forma summary of the combined Woodside and BHP Petroleum Reserves and Contingent Resources, as if one entity, is presented in Appendix IV.

Prospective Resources Summary

Woodside's global exploration portfolio consists of assets in Australia, Senegal, Korea and Congo. They contain Prospects and Leads ranging from near-field exploration (NFE) opportunities in Australia and Senegal to stand-alone exploration projects in Australia, Korea and Congo.

All of the Prospects/Leads mentioned here could potentially be drilled within the next five (5) years; additional prospectivity with no firmly planned drilling has been excluded from the assessment.

Woodside has identified nine gas Prospects/Leads with 2U (Best estimate) Prospective Resources varying between 30 and 769 Bscf and Chance of Geologic Success (P_g) between 15% and 72%, plus two oil Prospects with 2U Prospective Resources varying between 40 and 375 MMBbl and P_g between 24% and 91%.

BHP Petroleum's global exploration portfolio consists of assets in Mexico, Trinidad and Tobago, Canada, Australia and USA. They contain Prospects ranging from NFE opportunities in Mexico, Trinidad and Tobago, Australia and USA to stand-alone exploration projects in the USA and Canada. Other Prospects such as those in Barbados and Egypt are not discussed as they are not sufficiently mature to be included in this assessment.

BHP Petroleum has identified two gas Prospects with 2U Prospective Resources varying between 85 and 300 Bscf and P_g between 85% and 90%, plus 11 oil Prospects with 2U Prospective Resources varying between 4.4 and 440 MMBbl and P_g between 11% and 90%.

GaffneyCline has reviewed the Prospects and Leads mentioned above. This review has broadly confirmed the assessments by the companies, although GaffneyCline has modified both the Prospective Resource estimates and P_g where it deems it to be required. These changes do not unduly impact the overall exploration portfolios of the companies.

It should be noted that the P_g reported here represents an indicative estimate of the probability that drilling a prospect would result in a discovery. This does not include any assessment of the risk that the discovery, if made, may not be developed. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.

NPV Summary

Reference Post-Tax NPVs for the Proved and the Proved plus Probable Reserves cases, at a discount rate of 10%, are summarised in Table 4 for the assets of Woodside (a) and BHP Petroleum (b).

Table 4: Summary of Post-Tax NPV (US$ MM) at 10% Discount Rate of Future Cash Flow from Reserves, Net to Company, as at 31st December 2021

(a) Woodside

Country	Asset / Project	Post-Tax Net Present Value (US$MM) at 10% Discount Rate	
		Proved	Proved plus Probable
Australia	North West Shelf	1,567	2,244
	Wheatstone	2,057	2,834
	Pluto	7,712	8,807
	Scarborough	1,140	2,419
	Greater Enfield	233	514
Senegal	Sangomar	1,198	2,265
Total		**13,907**	**19,083**

(b) BHP Petroleum

Country	Asset / Project	Post-Tax Net Present Value in (US$MM) at 10% Discount Rate	
		Proved	Proved plus Probable
Australia	North West Shelf	1,520	2,170
	Bass Strait	898	1,695
	Macedon	227	267
	Pyrenees	69	197
	Scarborough	411	872
US GOM	Shenzi	1,610	2,319
	Shenzi North	265	588
	Atlantis	1,190	3,293
	Mad Dog	2,258	3,113
Trinidad & Tobago	Angostura	79	129
	Ruby	15	53
Total		**8,542**	**14,697**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the assets.
2. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. The NPVs reported here do not include any corporate adjustments, such as net debt or corporate costs, and as a result should not be used to assess the relative net asset values of the two companies.

Discussion

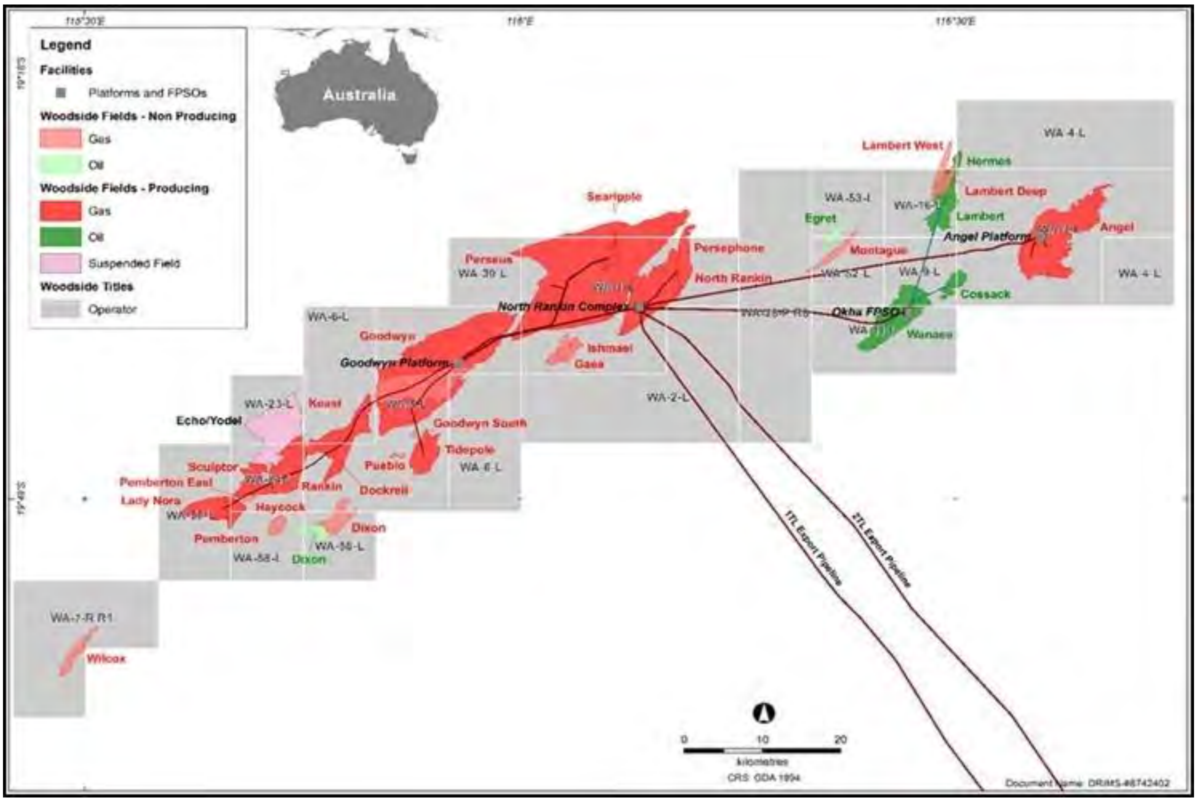
Woodside Assets

1 Woodside Australia

1.1 North West Shelf Gas

The North West Shelf (NWS) gas fields are located about 130 km offshore Western Australia (Figure 1). The produced gas is gathered at the North Rankin complex and then sent to the Karratha Gas Plant (KGP) via two export pipelines. The end products are domestic gas and export LNG. Woodside operates the NWS gas fields and holds a 15.78% stake in the joint venture which comprises BHP Petroleum, Chevron, BP, Shell, MIMI and CNOOC. Woodside owns 16.67% of NWS pipelines and KGP. CNOOC is not partner in pipelines and KGP.

Figure 1: North West Shelf Gas and Oil Fields

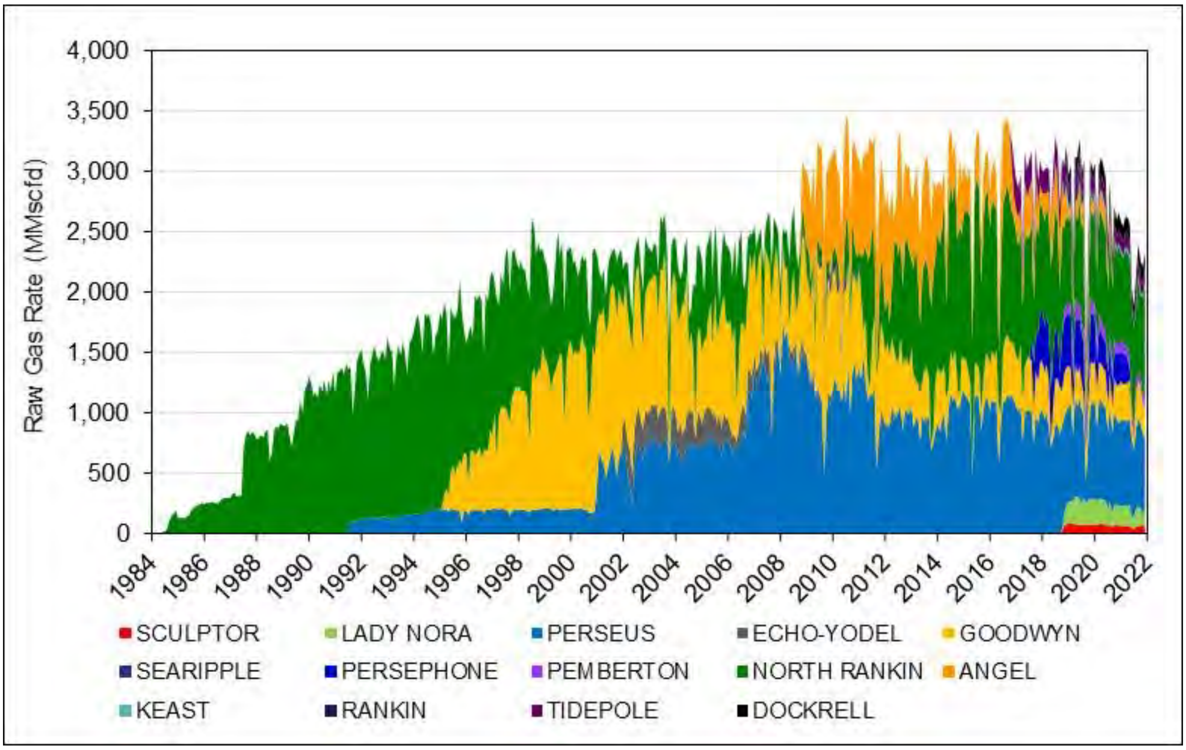


Source: Woodside

1.1.1 Field Description and Recoverable Volumes

Gas production began in 1984 from the North Rankin field (Figure 2). Since then, 12 more fields have been brought online, with four not on production as of 31st December 2021 (Table 5). The earliest fields brought online (North Rankin, Perseus, Goodwyn) were mainly developed with platform wells. Goodwyn and North Rankin both had gas injection/cycling to improve recovery of condensate for much of their early history. Later fields were mainly developed with subsea tie-back wells. As export capacity continued to grow with the addition of more trains, so did production, which eventually peaked at 3 Bscfd in 2008 (corresponding to the offshore production rate required to keep the KGP full). However, since 2021, production from the NWS has been offshore constrained, with production declining in most fields. To maximize gas supply to the KGP, effort is ongoing to upgrade water handling capabilities, shut-off water production, add perforations to existing producers and reduce separator pressure.

Figure 2: North West Shelf Gas Fields Historical Production



Source: Data from Woodside

Table 5 provides a summary of the gas fields in the NWS area, including non-producing discoveries. Woodside's forecasts shows that the top four fields (North Rankin, Perseus, Goodwyn and Lady Nora-Pemberton) collectively contribute over 80% of the total NWS gas 2P gross Reserves. As such, GaffneyCline has focused the analysis of NWS Gas on these four fields (excluding the Goodwyn GDEFA reservoir due to its small volumes). An overview of the properties of these fields/reservoir groups is shown in Table 6.

Table 5: Gross Technically Remaining Recoverable Volumes by Field as at 31st December 2021

Field	Status	Produced Raw Gas (Bscf)	Remaining Recoverable			
			Low Estimate		Best Estimate	
			Gas (Bscf)	Cond. (MMBbl)	Gas (Bscf)	Cond. (MMBbl)
North Rankin	Producing	9,501	1,680	25.7	1,912	27.9
Perseus	Producing	7,611	1,080	22.2	1,829	34.1
Goodwyn	Producing	4,771	1,052	24.5	1,105	25.9
Lady Nora-Pemberton	Producing	299	306	7.7	445	10.4
Persephone (*)	Not producing	448	0	0.0	0	0.0
Dockrell	Producing	124	165	6.0	285	9.7
Keast	Producing	26	62	1.1	81	1.4
Sculptor-Rankin	Producing	116	0	0.0	102	2.5
Tidepole	Producing	280	189	3.8	188	3.7
Angel (*)	Not producing	2,129	0	0.0	0	0.0
Searipple	Not producing	59	0	0.0	0	0.0
Echo-Yodel	Not producing	534	0	0.0	0	0.0
Lambert Deep	Execute	0	190	1.9	193	1.9
Total		**25,898**	**4,724**	**92.9**	**6,140**	**117.5**

Notes:

1. The top four fields account for approximately 80% of the NWS total remaining technically recoverable gas volumes (Best estimate).
2. Persephone Field (*) is not producing, although attempts have been made to restart one well. Angel Field (*) is not producing. The Angel NE attic infill well was re-evaluated during 2019; however it remains commercially not viable.
3. Remaining Recoverable Volumes are remaining technically recoverable volumes with no economic cut-off applied.
4. Gas volumes reported in this table are “wellhead” or “wet” volumes. Adjustments to sales gas volumes are accounted for in the economic evaluation for Reserves reporting.
5. Produced Raw Gas is total produced gas minus injection.

Table 6: Subsurface Description of Main NWS Gas Fields

	North Rankin	Perseus	Goodwyn		Lady Nora/ Pemberton
			GG	GH	
Formation	Mungaroo, Brigadier & NR	Oxfordian & Legendre	Brigadier & Mungaroo	Brigadier & Mungaroo	Brigadier & Mungaroo
Datum Depth (mss)	3,000	3,000	2,800	2,839/3,028	3,000
Initial Pressure (psia)	4,720	4,396	4,400-4,500	4,439/4,709	4,654
Initial Temperature (°C)	106	109	108	116	116
Porosity (%)	16-20	20-22	30	14-22	21
Permeability (mD)	130-2,000	~100-1,000	100-1,000	1,000-5,000	4,000
Fluid Type	Wet gas	Wet gas	Wet gas	Wet gas	Wet gas

The longest producing gas field in the NWS is North Rankin, which was discovered in 1971 and appraised between 1972 and 1980. Twenty-two dry wellhead development wells have been drilled in the field to produce from the Upper and Lower reservoirs. As of YE2021, ~9.5 Tscf of gas had been produced (total produced gas minus injected gas) from North Rankin. Despite the age and maturity of the field, North Rankin is expected to contribute significantly to future NWS gas production until the end of the shelf's life; the field also serves as swing producer for the shelf. North Rankin production is currently in decline; work performed from 2019 through 2021 has been successful in reducing the decline.

Located about 20 km west of the North Rankin field is the Perseus field (Figure 1), discovered in 1972 and appraised in 1990. First production was in 1991, followed by further appraisal in 1995 and 1996. Perseus was found to extend into the neighbouring licence block held by Mobil and Phillips in 1997. Following that, in 2001, the NWS venture participants together with Mobil and Phillips signed the Perseus/Athena Cooperative Development Agreement (PACDA) which governs the development, production and operation of the Perseus field. Production from Perseus comes through ten wells, seven of which are from the North Rankin A platform, while the remaining three are subsea wells tied back to the Goodwyn A platform. As of YE2021, nine wells remain active. Perseus production is in decline; work performed from 2019 to 2021 has helped to slow the decline.

The Goodwyn gas condensate field is located about 30 km southwest of the North Rankin field. Discovered in 1971, production from Goodwyn commenced in 1995 upon the completion of the Goodwyn A platform and to date, 21 development wells have been drilled and completed. The field comprises a series of stacked reservoirs dipping northwards, sub-cropping the overlying Cretaceous shales that provide the up-dip seal. Two of the 21 development wells produce from the GH reservoir units; four produce from the GG reservoir units (GF5-GG4); another three produce from the GDEFA (GD4-GF3) reservoir units. Due to the small volumes in Goodwyn GDEFA, GaffneyCline has focused its analysis of Goodwyn on the GG and GH reservoir groups. Goodwyn GG production is currently in decline; work performed in late 2019 and early 2020 has helped to boost recent production. Within the same field, the Goodwyn GH reservoir produced steadily at 150 MMscfd between mid-2016 and mid-2018. In late 2018, production rate was stepped down to around 125 MMscfd and has been in slow decline since. Three new infill wells were recently drilled to boost production from the Goodwyn GH reservoir starting in 2022, based on Woodside's 2H2021 Long Term Forecast.

The Lady Nora-Pemberton fields are located about 70 km southwest of the North Rankin field. Lady Nora-Pemberton comprises two separately discovered fields: the Pemberton field discovered in 2006, and the Lady Nora field discovered in 2007. Three development wells have been drilled and completed in 2018 as gas cap producers. The two fields were found to be in communication due to pressure responses observed in the LPA01 well (Pemberton) prior to coming online, due to production from the LPA02 and LPA03 wells (Lady Nora). All three wells are tied back to the Goodwyn A platform. Lady Nora-Pemberton gas production is currently in decline.

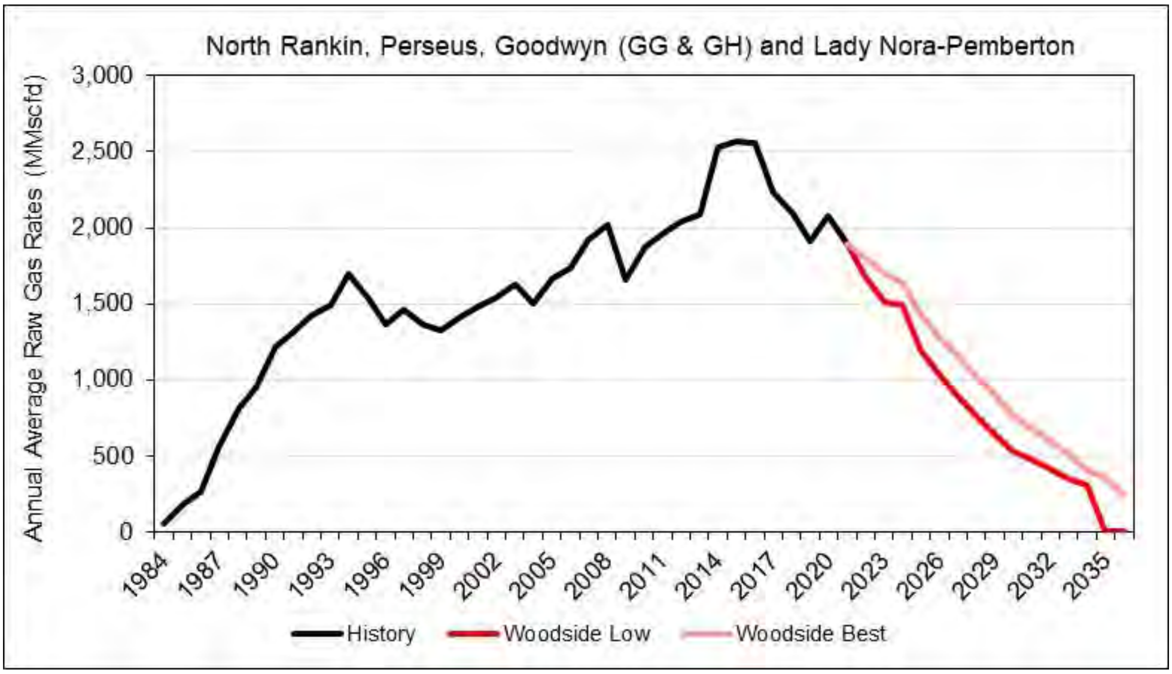
1.1.2 Field Development and Production Profiles

GaffneyCline has carried out Decline Curve Analysis (DCA) to review Woodside's production forecasts and estimates of technical remaining developed volumes individually for each of the major fields or reservoirs, North Rankin, Perseus, Goodwyn (GG & GH) and Lady Nora-Pemberton. Woodside's forecasts have been generated using a combination of dynamic and network modelling. At the aggregated level, the difference in volumes estimated by Woodside and GaffneyCline is within tolerance. As these fields/reservoirs collectively constitute more than 80% of the NWS Gas volumes, GaffneyCline has accepted Woodside's NWS gas forecasts for estimating Reserves. Woodside's Long Term Forecasts are the individual asset team's view of the production and cost profiles, effectively the designated latest business view. GaffneyCline understands that Woodside may use more recent performance data and technical models for its reserves estimates. GaffneyCline evaluated production data up to end 2021 to opine on the reasonableness overall of the Long Term Forecasts provided, and used these in making GaffneyCline's estimates of reserves. GaffneyCline also used average heating values rather than values per component. Differences may therefore exist between GaffneyCline's and Woodside's reserves estimates. Figure 3 shows Woodside's aggregated forecasts for the top four fields. Both Woodside and GaffneyCline's forecasts exhibit continued decline in these fields, with compression and infill wells having minor effects in reducing the decline.

For condensate, GaffneyCline has compared the ratio of Woodside's condensate to gas forecasts against historical condensate/gas ratios (CGR) for each field, which are reasonably in line. On the basis of this comparison, GaffneyCline deems Woodside's condensates forecasts reasonable.

For undeveloped volumes associated with infill wells (applicable to Goodwyn GG), GaffneyCline has constructed type curves based on analogue wells for forecasting. Undeveloped volumes associated with compression have been forecast by extending DCA forecasts. Table 5 summarizes Woodside's estimated technical remaining volumes for the NWS Gas fields, which GaffneyCline has accepted.

Figure 3: Top Four Fields Aggregated NWS Gas Production History and Forecasts



1.1.3 Contingent Resources

GaffneyCline has reviewed Woodside's Contingent Resources and has found them reasonable. Woodside's Contingent Resources opportunities in NWS Gas and their estimated 2C volumes are reported in Table 7 and Table 8.

Table 7: Gross Contingent Resources for Developed NWS Gas Fields as at 31st December 2021

Field	PRMS Sub-Classification*	2C Contingent Resources		Descriptions
		Dry Gas (Bscf)	Cond. (MMBbl)	
Angel	Not Viable	63	3	1 infill well
Dockrell	Unclarified	101	5	2 infill wells
Goodwyn	Pending	3	0	1 well workover
	Pending	26	0	1 facility upgrade
	Unclarified	109	5	3 well workovers, 2 facility upgrades
Keast	Pending	45	2	1 infill well
North Rankin	Unclarified	165	3	2 facility upgrades
	Unclarified	78	1	1 infill well
Persephone	Not Viable	18	2	1 infill well
Perseus	Unclarified	444	15	1 facility upgrade
Sculptor	Unclarified	35	1	1 infill well, cyclic production
Tidepole	Unclarified	147	4	2 infill wells, 1 facility upgrade
	Not Viable	16	1	1 infill well
Totals		**1,249**	**42**	

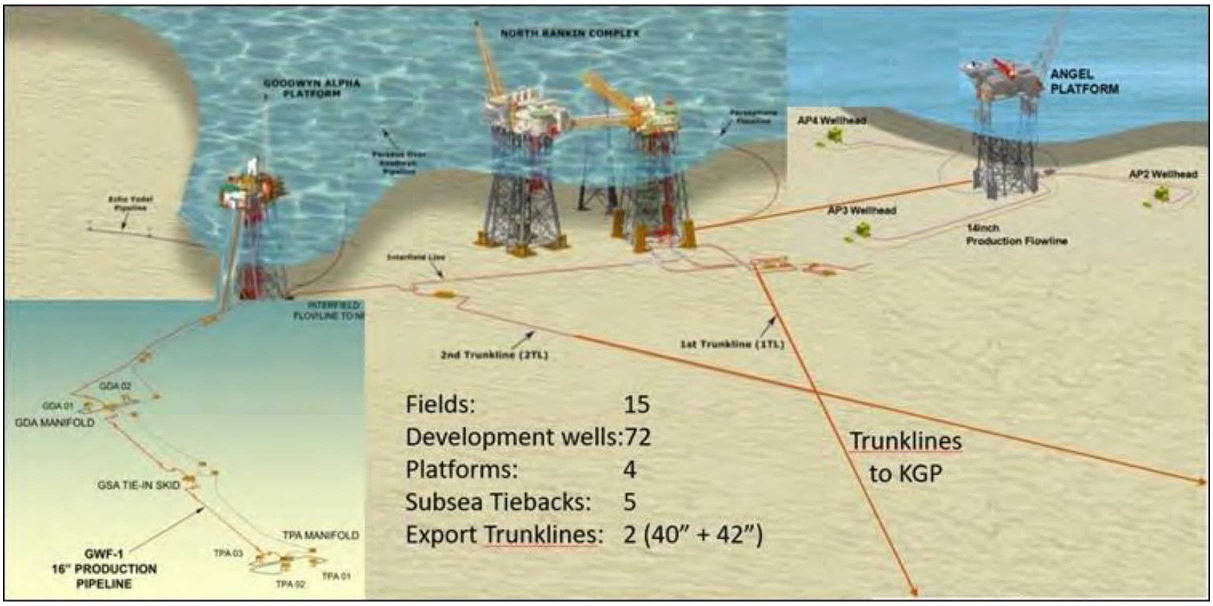
Table 8: Gross Contingent Resources for Undeveloped NWS Gas Fields as at 31st December 2021

Field	PRMS Sub-Classification*	2C Contingent Resources	
		Dry Gas (Bscf)	Cond. (MMBbl)
Tidepole East	Unclarified	49	2
Wilcox	Unclarified	133	7
Dixon	Unclarified	138	4
Haycock	Not Viable	6	0
Montague	Not Viable	57	2
Gaea & Ishmael	Not Viable	100	3
Lambert West	Not Viable	63	1
Pemberton East	Not Viable	15	0
Totals		**561**	**19**

1.1.4 Facilities and Cost Estimates

The offshore development comprises four conventional platforms (Goodwyn A, North Rankin A & B, and the Angel platform) hosting platform wells and subsea tiebacks. Export compression is provided on both the Goodwyn and North Rankin platforms delivering gas to two export trunklines (40” and 42”) 185 km to KGP (Figure 4).

Figure 4: North West Shelf Facilities (Composite)



Source: Woodside

The NWS offshore facilities operate at high reliability with North Rankin reporting 99.7% reliability, Goodwyn A 99.2%, and Angel 98.3%.

KGP came on stream in 1989 from 2 x 2.5 MTPA LNG trains, with an additional 2.5 MTPA train added in 1992. Trains 4 and 5, each of 4.7 MTPA were added in 2004 and 2008 respectively, bringing total capacity to 16.9 MTPA LNG export capacity, requiring 3,000 MMscfd feed gas from offshore. As the offshore fields are declining, there is available ullage to process non-NWS gas.

As the offshore fields decline, the overall system turndown rate can be stepped down by shutting down LNG trains, and by ceasing production through one of the two export trunk lines. In this way, the minimum facilities throughput can be reduced to 350 MMscfd into a single liquefaction train (Train 5), at 2 MTPA LNG production rate.

The Pluto-KGP interconnector line allows Pluto gas to be processed at KGP, forecast to commence in 2022 at some 100 to 150 MMscfd. In 2024, some 200 MMscfd of third party gas from the onshore Waitsia development is planned. The plant will earn tolling revenues from these liquefaction agreements. The most material backfill opportunity comes from development of the Browse fields (Section 1.9), where the current development concept will process up to 1.9 Bscfd of gas through the KGP facilities, potentially extending facilities life by 15 years to 2058.

The NWS offshore facilities and the KGP have been in service for over 35 years with no significant unplanned service outages. Recent high level operability reports show upstream facilities reliability ranging from 98.3% to 99.7%, excellent performance for facilities of this age. In the longer term, the two parallel gas export lines and five parallel liquefaction trains at the KGP provides the opportunity to step down system capacity as the offshore production declines.

The KGP provides gas sales access to the world LNG market, and is also linked to the Western Australian domestic market via the Dampier to Bunbury natural gas pipeline. The KGP is located next to, and is interconnected with, the Pluto LNG plant allowing some degree of capacity sharing between the two liquefaction facilities.

Decommissioning and Restoration (D&R) Planning is an ongoing activity in the NWS offshore operations. The Operator plans to spend an average of US$50 MM in real terms (RT) per annum continuously until the end of field(s) life, with the major offshore D&R program budgeted thereafter. Currently, D&R plans are being matured for the Echo-Yodel field, which ceased production in 2012.

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering CAPEX, OPEX and D&R costs for the NWS offshore and KGP onshore operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline's review of costs for all Woodside's Australian assets focused on consistency (all costs in RT2022 basis and consistent with the activity plan and production profile), and cost levels (checks focusing on OPEX vs. annual production, and D&R estimates). The detailed costs were analysed and categorized to support economic analysis. For NWS, GaffneyCline accepted Woodside's detailed cost forecasts as reasonable.

Gross CAPEX for further development activities relating to the NWS gas Reserves case is estimated to be US$4,841 MM.

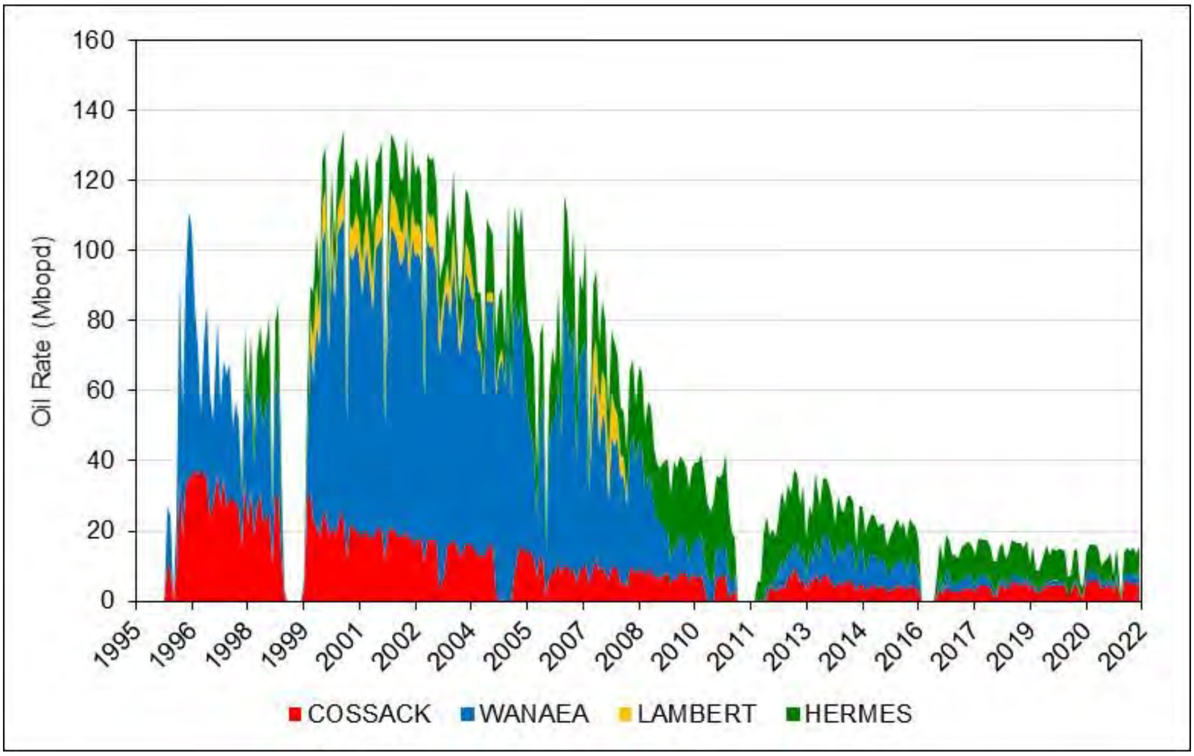
1.2 North West Shelf Oil

The NWS oil fields, located offshore Western Australia, consist of three producing fields (Cossack, Wanaea, and Hermes) and a fourth field, Lambert, which has ceased production (Figure 1). Additionally there are three undeveloped discoveries: Egret, Eaglehawk and West Dixon.

1.2.1 Field Description and Recoverable Volumes

Oil production began in 1995 from the Cossack and Wanaea fields (Figure 5) followed by Hermes and Lambert in 1997 and 1999 respectively. Production gradually ramped up until 2010, after which rates have been in decline. The Lambert field stopped producing in 2008 after recovering 17.5 MMBbl of oil. The Cossack, Wanaea and Hermes fields are producing through the Okha FPSO. Table 9 shows a summary of the reservoir properties and the estimated remaining recoverable volumes are shown in Table 10.

Figure 5: NWS Oil Fields Production History



Source: Data from Woodside

Table 9: Subsurface Description of producing NWS Oil Fields

	Cossack	Wanaea	Lambert	Hermes
Initial Pressure (psia)	4,240-4,510			
Initial Temperature (deg C)	108-114			
Porosity (%)	16.5-18.5			
Permeability (mD)	200-800			
Fluid Type	Oil			

Table 10: Estimates of Gross Remaining Technically Recoverable Volumes by Field as at 31st December 2021

Field	Status	Produced		Remaining Recoverable			
				Low Estimate		Best Estimate	
		Oil & Condensate (MMBbl)	Gas (Bscf)	Oil (MMBbl)	Raw Gas (Bscf)	Oil (MMBbl)	Raw Gas (Bscf)
Cossack	Producing	97	13	9	0.1	11	0.6
Wanaea	Producing	270	306	1	0.0	5	0.3
Lambert	Ceased	18	5	0	0.0	0	0.0
Hermes	Producing	118	42	15	0.1	15	0.8

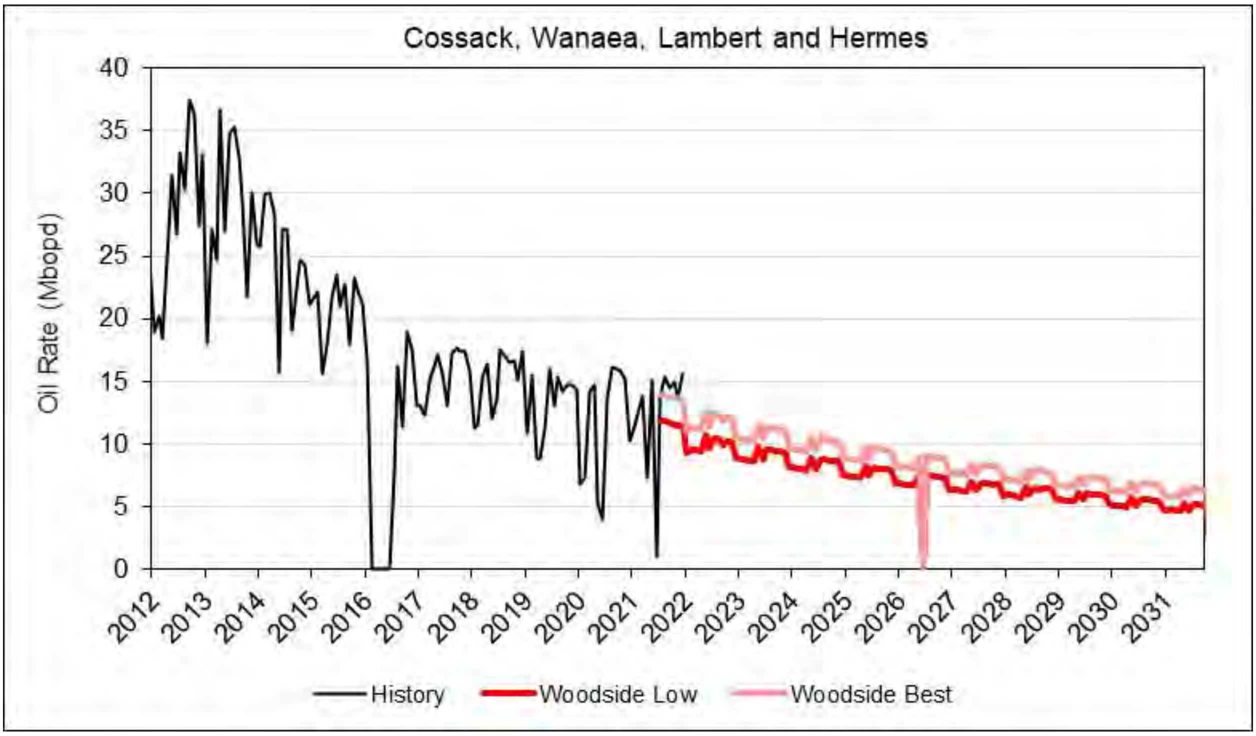
Note:

1. Volumes shown here are remaining technically recoverable volumes with no economic cut-off applied.

1.2.2 Field Development and Production Profiles

GaffneyCline has reviewed Woodside's production forecasts for producing fields by carrying out DCA at the aggregated field level. The volumes under both the GaffneyCline and Woodside profiles are within tolerance and GaffneyCline has accepted Woodside's forecasts in Figure 6, which correspond to the recoverable volumes in Table 10, for reporting Reserves. No future activities are planned for the producing fields.

Figure 6: Aggregated NWS Oil Recent Production History and Forecasts



1.2.3 Contingent Resources

GaffneyCline has reviewed Woodside's estimates of Contingent Resources using a similar methodology to the NWS Gas review and has found Woodside's estimates to be reasonable. Woodside's Contingent Resources opportunities in NWS Oil and their estimated 2C volumes are reported in Table 11 and Table 12.

Table 11: Gross Contingent Resources for Developed NWS Oil Fields as at 31st December 2021

Field	PRMS Sub-Classification	2C Contingent Resources		Descriptions
		Oil (MMBbl)	Dry Gas (Bscf)	
Cossack	Unclarified	6.9	0.94	1 infill well
	Unclarified	6.4	0.87	1 facility upgrade
	Not Viable	0.7	0.10	1 well workover
Wanaea	Not Viable	0.9	1.15	4 well workover, 1 well workover
Lambert	Unclarified	0.9	0.29	1 well workover
Hermes	Unclarified	0.2	0.08	1 facility upgrade
	Unclarified	7.2	2.82	1 facility upgrade
Totals		**23.2**	**6.24**	

Note:

1. Raw gas CR were calculated using GOR of 138, 1,289, 330 and 395 scf/stb for Cossack, Wanaea, Lambert and Hermes respectively.

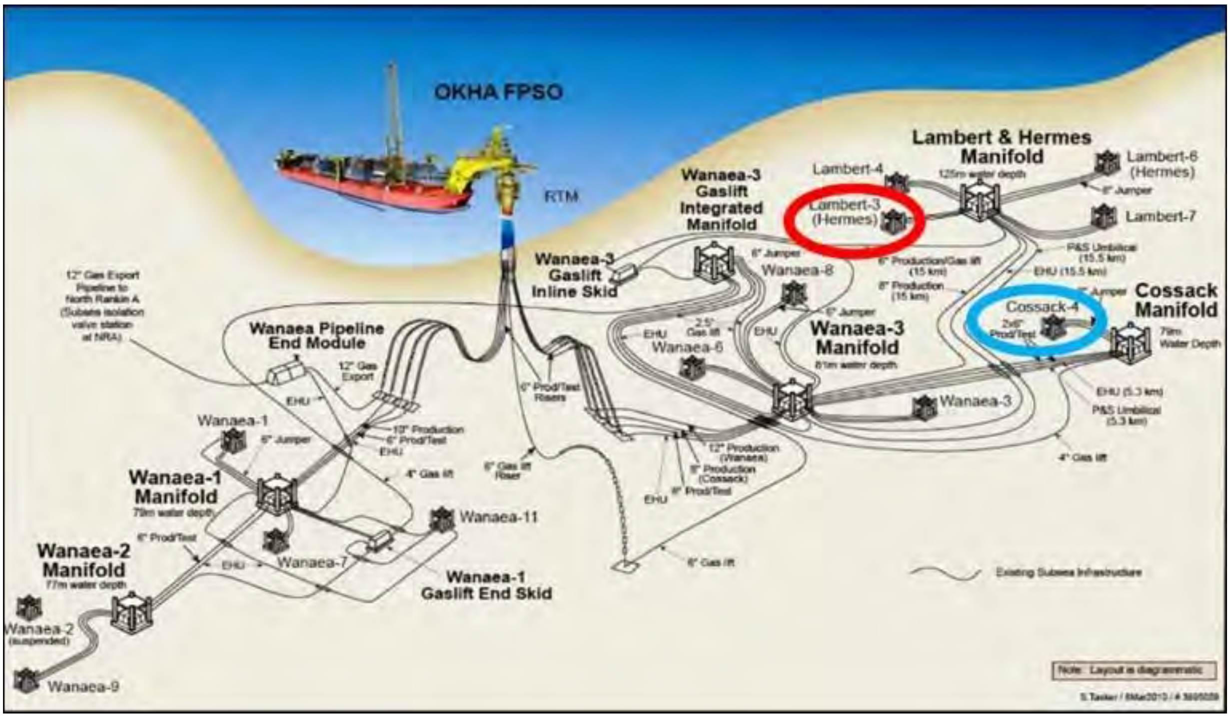
Table 12: Gross Contingent Resources for Undeveloped NWS Oil Fields as at 31st December 2021

Field	Development Status	2C Contingent Resources	
		Oil (MMBbl)	Dry Gas (Bscf)
Eaglehawk	Not Viable	0.3	0.00
Egret	Not Viable	7.3	6.70
West Dixon	Not Viable	2.3	0.00
Totals		**9.9**	**6.70**

1.2.4 Facilities and Costing

The NWS Oil fields produce to the Okha FPSO (Figure 7). The development originally used the Cossack Pioneer FPSO, however this was replaced by the Okha in 2011. The four fields are developed with 13 subsea wells in 80 to 100 m water depth, of which five are in fulltime production and eight are shut in. The Okha processing capacity of 60 Mbopd and 150 Mblpd is greater than current production rates. Okha UWILD (Under Water Inspection In Lieu of Drydocking) was completed in 2021. The subsea infrastructure has experienced integrity issues, however, Woodside's management of change process is used to manage any integrity issues as they arise. Facility lifetime extension projects have been completed.

Figure 7: NWS Oil Fields Development



The NWS oil facilities (OKHA FPSO) have been in service for over 25 years with production outages every five years (2011, 2016, and 2021) for planned dry dock and vessel inspection. As noted above, the subsea infrastructure has experienced reliability issues (primarily in the controls system) which are being addressed in the maintenance and repair program. In 2020, OKHA system reliability, at 86%, fell below targeted levels. The 2021 turnaround workscope should have improved this performance.

The OKHA production system allows independent oil export, supported by a gas export pipeline to North Rankin A.

As noted in Section 1.1.4, current operational planning is focused on facilities uptime and integrity, with limited near-term D&R activity. The Operator has, however, developed a phased D&R plan commencing at the end of field life and extending over 8 years thereafter. Recent regulatory focus on prompt D&R planning and execution may accelerate this phasing.

GaffneyCline has reviewed a detailed cost forecast provided by Woodside covering CAPEX, OPEX, and D&R costs for the NWS oil operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline accepted Woodside's CAPEX and OPEX cost forecasts as reasonable. D&R cost estimates, however, were materially increased in our review to reflect current D&R scope and the full exploration, appraisal and production well count remaining.

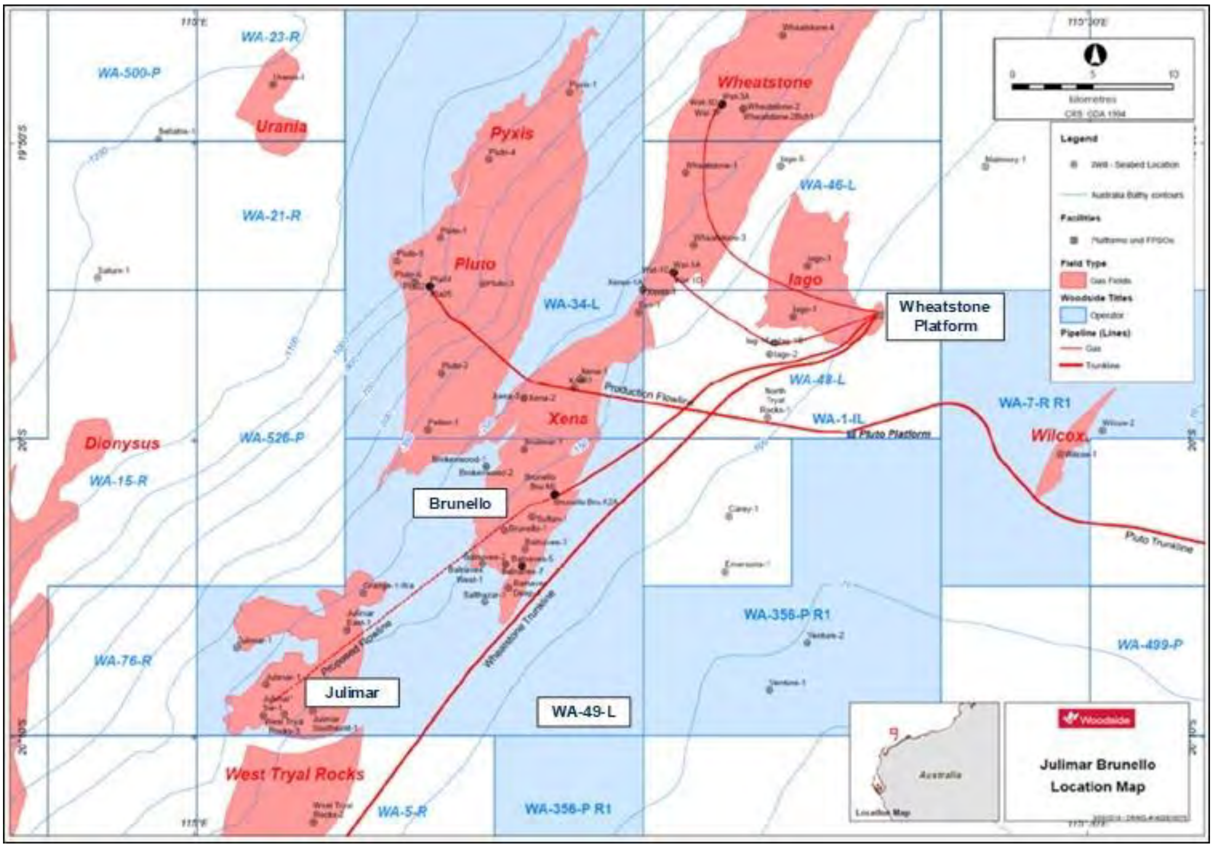
Gross CAPEX for further development activities relating to the NWS oil Reserves case is estimated to be US$80 MM.

1.3 Wheatstone LNG (Brunello-Julimar)

1.3.1 Field Description

Woodside acquired its 65% interest in the Brunello and Julimar Fields from Apache in 2015. The fields are contained within the WA-49-L permit, located in the Carnarvon Basin, offshore Western Australia and together form the Julimar Development Project (Figure 8). The Julimar Development Project is a subsea development to supply raw gas and condensate from the fields to the Chevron-operated Wheatstone platform and from there to the Wheatstone Project's onshore LNG trains and domestic gas plant at the Ashburton North Strategic Industrial Area.

Figure 8: WA-49-L Location Map



Source: modified from Woodside

The Julimar Field was discovered in 2007 with the drilling of the Julimar-1 well which encountered gas bearing fluvial channel sands of the Triassic Mungaroo Formation. The field consists of NE-SW trending stacked Mungaroo fluvial channel belts which are often isolated via intra-formational seals and dipping shallowly to the north. In total there is approximately 600 m of accumulation thickness and the field is bounded by major faults to the east and west and stratigraphically trapped to the north. Multiple pressure regimes, fluid compositions, gas-water contacts and residual gas columns have been identified during appraisal drilling. Field development is heavily reliant on seismic data to define geobody extent and hydrocarbon contacts in unpenetrated sands. Woodside has completed the JDP2 drilling program and commissioning began in early December 2021.

The Brunello Field was also discovered in 2007 with the drilling of the Brunello-1/ST1 well approximately 17 km northeast of the Julimar-1 discovery well. Brunello-1/ST1 encountered 37 m of net pay in the Mungaroo. The field is located on the Brunello Horst and is composed of a number of gently dipping Triassic Mungaroo sandstones that sub-crop the regional Base Cretaceous Unconformity. The structure is low relief with a maximum gas column of ~40 m, bound to the south by a sub-crop boundary and to the east and west by faults. Communication between reservoirs is uncertain and pre-production depletion from neighbouring fields suggests complex communication pathways.

GaffneyCline has made probabilistic (Monte Carlo) estimates of the GIIP for the Julimar and Brunello Fields (Table 13). Inputs allowed for uncertainties in mapping, petrophysical properties and fluid contacts.

Gas production from Brunello commenced on 18 September 2017 from well BruA-4ST3, sand B6. The remaining four wells, BruA-2A (sand B8), BruA-3 (sand B7), BruA-5ST1 (sand B10) and BruA-6 (sand B50), were put on production the following month. Production from BruA-6 has been constrained (<20 MMscfd) due to higher than anticipated mercury levels in the deeper B50 reservoir. Cumulative raw gas production as of 31st December 2021 is 454 Bscf (Table 14 and Figure 9). BruA-2A and BruA-5ST1 are the two main producers and have contributed 67% of total production thus far.

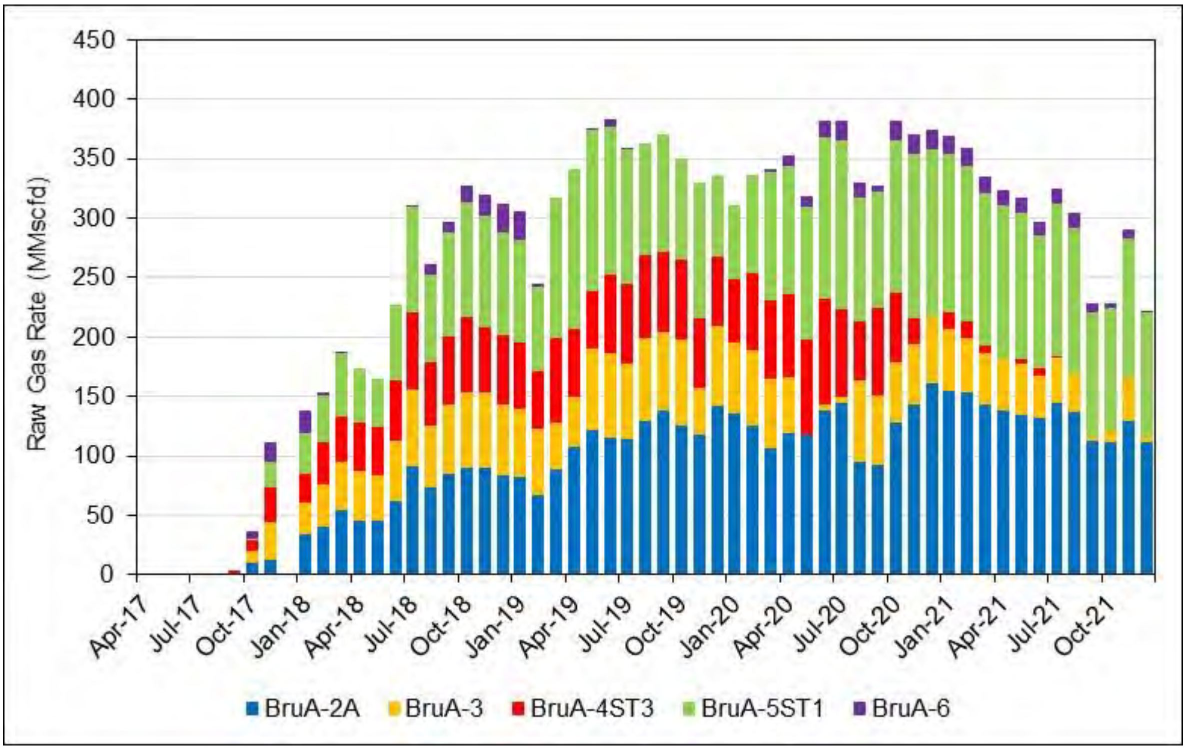
Table 13: Estimates of GIIP for the Brunello and Julimar Fields

Field	Reservoir / Sand	GIIP (on and off Block) (Bscf)	
		Low Estimate	Best Estimate
Brunello	B6	348	448
	B7	86	134
	B8 / B9	357	449
	B10	412	547
	B49	47	82
	B50	181	271
	B60	149	216
	Total	**1,580**	**2,146**
Julimar	J12	25	53
	J14	68	89
	J16	47	85
	J25	167	285
	J45	53	113
	J50	111	156
	J54	93	123
	J56	217	285
	J65	63	104
	J67	107	144
	J75	14	26
	J85	59	114
	Total	**1,025**	**1,578**
Total		**2,604**	**3,724**

Table 14: Brunello Historical Gas Production as at 31st December 2021

Well	Reservoir	Cumulative Produced Raw Gas (Bscf)
BruA-2A	B8/B9	161
BruA-3	B7	69
BruA-4ST3	B6	64
BruA-5ST1	B10	148
BruA-6	B50	12
Field		**454**

Figure 9: Brunello Historical Production as of 31st December 2021



BruA-4ST3 started to produce water in September 2020 and has been shut in since June 2021. BruA-2A experienced early formation water breakthrough in June 2021. The Brunello deep reservoirs (B50 and B60) have high mercury content, and currently B50 is only developed by the BruA-6 well, from which production is restricted.

In BruA-3 (Sand B7) the observed pressure is declining faster than expected, and in BruA-5ST1 (Sand B10) the pressure decline is less than previous forecast. Communication between the reservoir units is uncertain, pre-production depletion from neighbouring fields has suggested complex communication pathways with competitive drainage of Pluto/Xena fields. The B6 and B7 sands were originally thought to be connected, but production data shows communication between them to be negligible.

Julimar commenced production in the first week of December 2021 and total cumulative gas as of 31st December 2021 is 2.7 Bscf.

1.3.2 Field Development and Production Forecasts

Gas and condensate recovery factors have been estimated for all sands, taking into account historical performance. These were applied to the estimate of GIIP to estimate ranges of ultimate recovery using probabilistic methods and deterministic aggregation (Table 15).

Integrated reservoir production models have been prepared for supporting the production forecasting, by providing a sense of plateau lengths, Phase 3-4 well schedules, compression timings and decline rates. The final GaffneyCline Low and Best estimate production profiles were generated by scaling Woodside's Best estimate raw gas and condensate profiles to match GaffneyCline's Low and Best estimates of recoverable volumes. GaffneyCline's Low estimate of recoverable volumes utilises the average between an arithmetic addition and probabilistic addition of the individual Brunello and Julimar reservoirs to account for possible dependency criteria. Reservoirs J45 and B49 have been excluded based on the recent Julimar wells and Woodside development strategy. The summary of remaining recoverable volumes is provided in Table 16 and Figure 10 shows GaffneyCline's Low and Best raw gas and condensate production profiles for the Woodside Phase 1-4 development scenarios.

Table 15: Estimates of Ultimate Recovery for the Brunello and Julimar Fields

Field	Reservoir / Sand	Ultimate Recovery (on and off block)			
		Raw Gas (Bscf)		Condensate (MMBbl)	
		Low Estimate	Best Estimate	Low Estimate	Best Estimate
Brunello	B6	64	65	0.8	0.8
	B7	67	107	0.9	1.5
	B8 / B9	198	254	5.8	8.9
	B10	340	453	6.8	9.6
	B50	61	112	0.8	1.6
	B60	31	61	0.4	0.9
	Total	**761**	**1,053**	**15.5**	**23.3**
Julimar	J12	18	39	0.2	0.5
	J14	40	62	0.5	0.8
	J16	25	52	0.3	0.7
	J25	62	142	0.9	2.3
	J50	82	119	1.0	1.6
	J54	55	74	0.6	1.0
	J56	172	228	1.9	3.0
	J65	37	62	0.4	0.8
	J67	70	99	0.8	1.4
	J85	17	58	0.3	1.0
	Total	**576**	**934**	**6.9**	**13.1**
Total		**1,337**	**1,988**	**22.4**	**36.4**

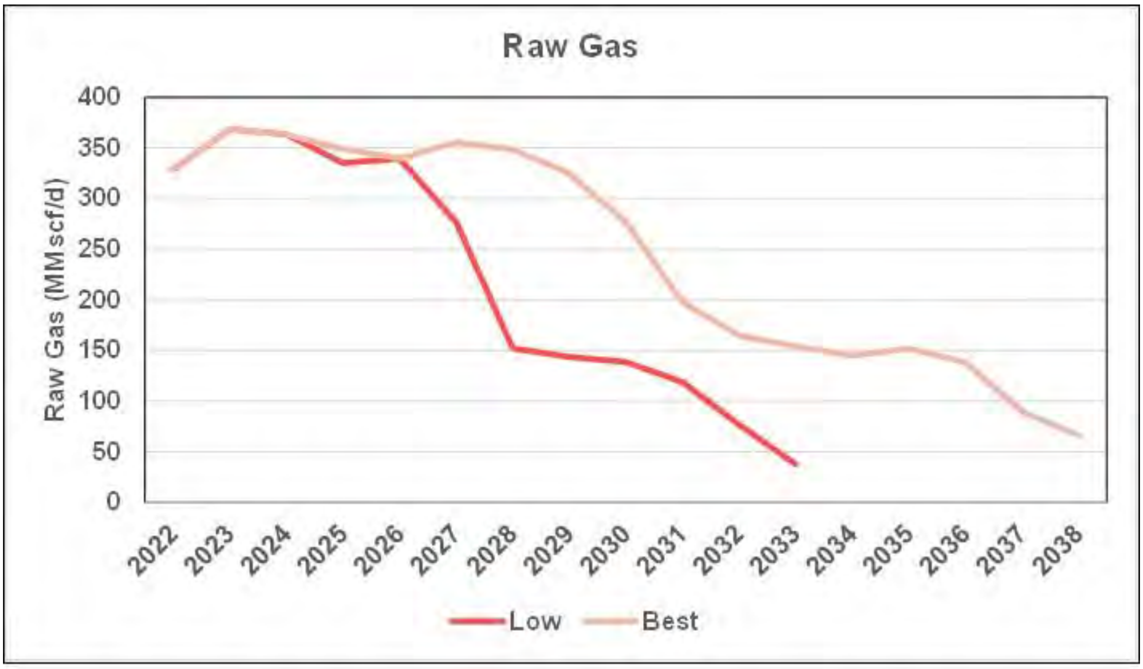
Table 16: Gross Remaining Recoverable Raw Gas and Condensate as at 31st December 2021

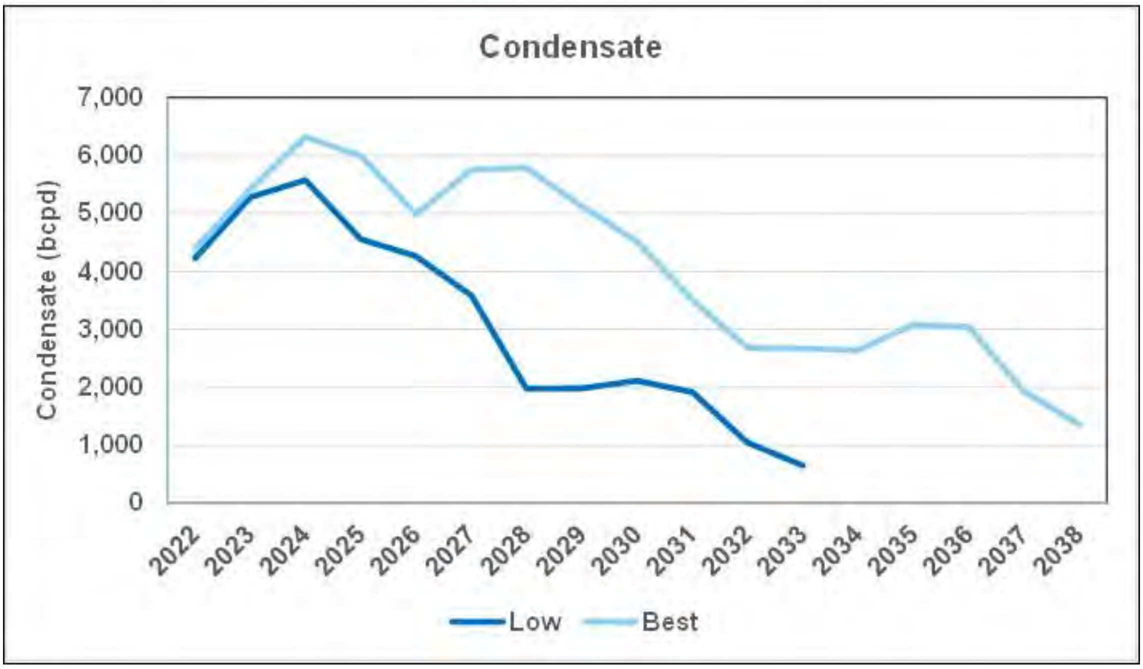
Commodity	Low Estimate	Best Estimate
Raw Gas (Bscf)	978	1,526
Condensate (MMBbl)	13.6	25.4

Notes:

1. Volumes shown here are remaining technically recoverable volumes with no economic cut-off applied.
2. Gas volumes reported in this table are "wellhead" or "wet" volumes. Adjustments to sales gas volumes are accounted for in the economic evaluation for Reserves reporting.

Figure 10: Wheatstone Raw Gas and Condensate Production Profiles





1.3.3 Facilities and Costing

The Wheatstone LNG fields are developed as a combined subsea tie-back development to the Chevron-operated Wheatstone platform. The project is a phased development and is summarised in Table 17.

Table 17: Brunello and Julimar Development Project Summary

Development Phase	Notional Timing	Field	Development
JDP1	RFSU 2017 (complete)	Brunello	5 wells, Brunello manifold, two flowlines to Wheatstone Platform
Compression Stage 1	Installed, commissioned May 2021	Julimar/Brunello	Compression
JDP2	Commissioned November 2021, online December 2021	Julimar	4 well subsea tie-back
JDP3	October 2025	Julimar	~4 well subsea tie-back
JDP4	April 2028	Julimar/Brunello	~2 well infill wells in existing manifolds plus mercury removal unit
Compression Stage 2	2031	Julimar/Brunello	Compression
Compression Stage 3	2037	Julimar/Brunello	Compression

The development of Julimar and Brunello consists of subsea gas production wells drilled from three main drill centres. Each well is, or is planned to be tied into a subsea manifold located at the drill centres. The manifolds will be connected using intra-field flowlines and connected to the Wheatstone Platform by twin raw gas production lines.

In the initial phase, which came on stream in 2017, the Brunello field was developed with five producing wells tied back 22 km to Wheatstone by two 18” flowlines. In a second development phase (currently in progress), the gathering system will be extended a further 22 km to tie in the Julimar field, and four Julimar development wells drilled. Phase 2 production commenced in December 2021. Subsequent phases will add up to six further Julimar development wells. The combined production is processed at the Wheatstone platform, where some 20% of capacity (or 388 MMscfd) is allocated to the Brunello-Julimar development. Within this overall constraint, production from the BruA-6 well must be limited to 20 MMscfd due to high mercury levels in this well. The upstream development is illustrated in Figure 11.

The Wheatstone platform, pipeline, and onshore LNG plant are operated by Chevron, with Woodside holding a 13% WI. After separation on the platform, gas and condensate are dehydrated and compressed for transport 225 km to the onshore LNG plant, together with gas and condensate from other Chevron-operated fields. The LNG plant is a two-train 10.4 MTPA liquefaction plant, which can also supply up to 200 TJ/day of domestic gas.

Figure 11: Brunello and Julimar Development Concept

Source: Woodside

As a subsea tieback to the Wheatstone development, the reliability of the Julimar-Brunello development is largely dependent on the uptime of the host platform facilities and the downstream Wheatstone LNG plant. Brunello has been in production since late 2017. Apart from Wheatstone-related production outages (e.g. LNG train shut downs), Brunello has experienced occasional production curtailment related to miscellaneous subsea equipment failures and high mercury levels in the produced gas of one well.

Woodside's D&R plan commences in the final year of Julimar-Brunello production and extends over six years. This is a reasonable D&R project phasing and is accepted by GaffneyCline. It is likely that Julimar-Brunello D&R will be carried out as a part of the larger Wheatstone decommissioning, so the actual timing may depend on the Wheatstone field performance.

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the offshore Julimar-Brunello and onshore Wheatstone operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline has accepted Woodside's detailed cost forecasts as reasonable.

Gross CAPEX for further development activities relating to the Brunello and Julimar Reserves case is estimated to be US$989 MM.

1.3.4 Resources Estimates

Reserves are attributed to development of Brunello and Julimar (Section 1.3.2). Contingent Resources (Development Unclarified) are attributed for the re-perforation of a well (BruA-6) in a shallow reservoir (B49) in Brunello (Table 18). Further evaluation is required for feasibility due to mercury contaminants.

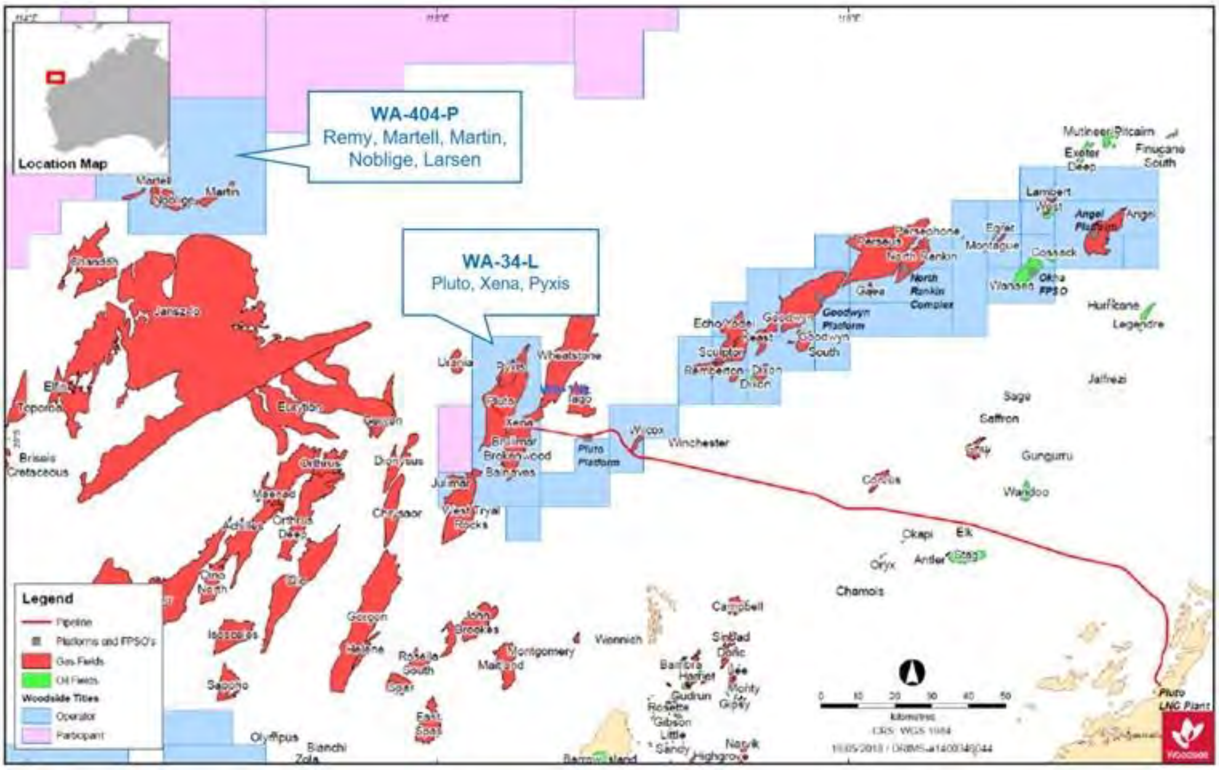
Table 18: Contingent Resources for Brunello as at 31st December 2021

Field	Gross 2C Contingent Resources	
	Dry Gas (Bscf)	Condensate (MMBbl)
Brunello (B49)	23.0	0.3

1.4 Pluto LNG

The Pluto LNG asset encompasses Pluto, Xena and Pyxis fields in the WA-34-L permit, located offshore Western Australia approximately 190 km northwest of Karratha (Figure 12). The Pluto Field is in 850 m water depth, while Xena is in 200 m and Pyxis is in 960 m. Pluto was discovered in 2005, within the exploration permit WA-350-P, which was awarded to Woodside in 2003. This was followed by the discovery of Xena (well Xena-1ST1) in 2006. Five Pluto appraisal wells and two Xena appraisal wells were subsequently drilled. The main reservoir in Pyxis was penetrated by the Pluto-4 appraisal well in 2006, and was appraised by Pyxis-1 well in 2015. The production licence WA-34-L was granted in 2007 and production of gas and condensate started from Pluto and Xena in 2012. Pyxis came on stream in November 2021.

Figure 12: Greater Pluto Location Map



Source: Woodside

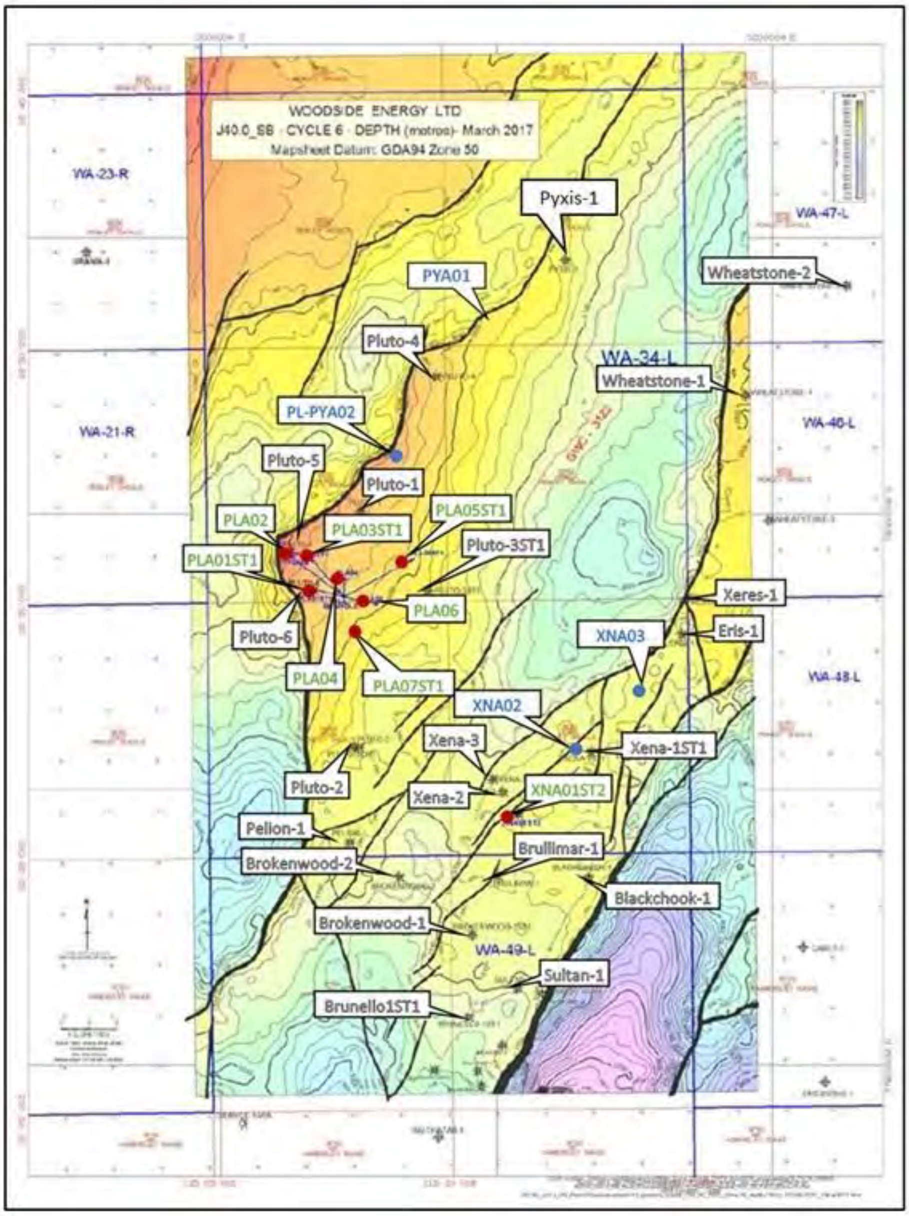
1.4.1 Field Description

The Pluto-Xena-Pyxis group of fields is located in the Northern Carnarvon Basin, up on the northern flank of the Dampier Sub-basin as it transitions into the Rankin Platform. Nearby major fields include the Brunello-Julimar Fields to the south, Wheatstone Fields to the northeast, and Jansz-Io further to the west.

The reservoirs of the Pluto and Xena fields are Late Triassic, fluvial deposits of the Mungaroo Formation, and the overlying Late Triassic, estuarine deposits of the Brigadier Formation. The Mungaroo reservoirs generally are good quality, with approximately 25% porosity and multi Darcy permeability, with slightly less better sandstone quality in the Brigadier Formation. The gas bearing reservoir in the Pyxis Field is the J40, middle-shoreface shallow water sandstone of the Late Jurassic (Oxfordian) Eliassen Formation. The reservoir has excellent quality, with average porosity approaching 30% and 2.5 mD average permeability. The top of the reservoir is encountered at a depth of around 3,000 mss.

The Pluto structure is an easterly tilted fault block, with major bounding faults as its western, north-western and northern margins and dip closure to the south and east. The Xena structure is a north-south trending horst block with dip closure to the south and on trend with Wheatstone Field to the north-east. The Pyxis accumulation is a combination of structural-stratigraphic trap, with low relief dip closing the eastern and northern side, faults closing its western side, and a pinch-out on its southern side. A structure depth map of the J40 formation in Figure 13 shows the location of the wells.

Figure 13: Structural Depth Map with Locations of Pluto, Xena and Pyxis Wells



Source: Woodside

1.4.2 Field Development and Production Forecasts

As of 31 December 2021, the greater Pluto area has been developed by eight subsea Pluto wells, including the Pluto north infill well PL-PYA02, which came online in November 2021. Pluto well PLA03 is unlikely to produce in the future, following water breakthrough in 2014. The Xena field is under development by a single well XNA01. Similarly, the Pyxis field is under development by a single development well PYA01, which came online in November 2021. By 31st December 2021 Pluto-Xena had produced 2,730 Bscf of dry gas and 10.6 MMBbl of condensate, and Pyxis had produced 3.4 Bscf of gas.

Future development will consist of drilling two additional wells: one well in Xena (XNA02), to come online in 2023, and a Pluto infill well (PLA08) that is not yet sanctioned and will come online in 2024. These wells will all be tied back to the existing Pluto/Xena development.

On the facility side, the Pluto water handling unit (PWH) on the Pluto A platform is expected to come online July 2022 with a design capacity of 22,000 bwpd. This is far higher than the existing capacity of 330 bwpd and this will greatly increase the flexibility to continue to flow wells that have experienced formation water breakthrough.

Woodside generates production forecasts from an ensemble of history-matched dynamic models, supported by a new 4D seismic survey that was acquired in 2020.

GaffneyCline estimated recoverable volumes of raw gas by multiplying the GIIP estimates with gas recovery factors derived from sensitivities run on the dynamic simulation model. GaffneyCline then compared the recoverable volumes and forecasts from Woodside and observed that they were within audit tolerance of 10%, and therefore GaffneyCline accepts the forecasts from Woodside.

The production profile used by GaffneyCline for evaluation reflects ullage availability, venture-agreed allocated liquefaction capacity and estimated field deliverability over time. Both the Low estimate and Best estimate production forecasts show gas rates varying between 950 and 1,050 MMscfd from 2022 to 2025 inclusive before declining.

Table 19: Pluto LNG Remaining Technically Recoverable Volumes as at 31st December 2021

Field	Low		Best	
	Raw Gas (Tscf)	Condensate (MMBbl)	Raw Gas (Tscf)	Condensate (MMBbl)
Pluto/Xena/Pyxis	1.8	22	2.3	27

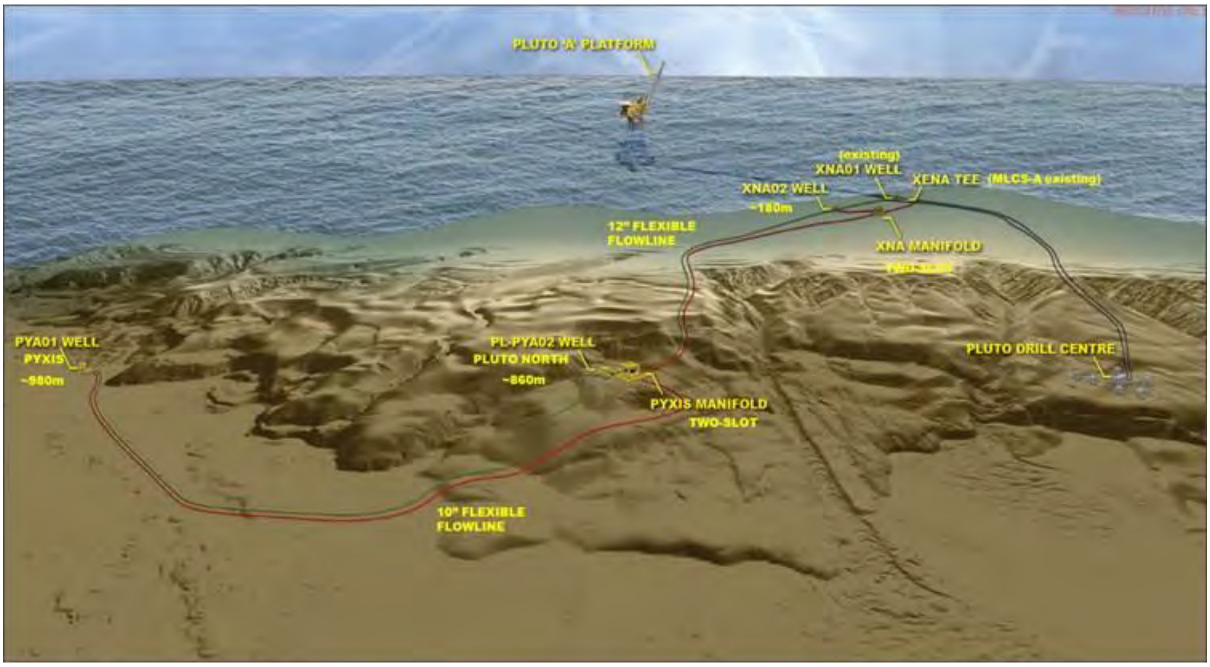
Note:

1. Volumes shown here are remaining technically recoverable volumes with no economic cut-off applied.

1.4.3 Facilities and Costing

The subsea wells of Pluto are tied back 27 km to the shallow water (85 m), not normally manned Pluto A platform where water handling and well control facilities are located. The single well Xena field development also ties into this subsea system. From Pluto A, full reservoir production flows to shore in a 36” x 180 km trunk line to the Pluto LNG plant. The Pluto development wells are large-bore, high capacity wells which, together the Xena well, can supply 900 MMscfd to Pluto LNG Train 1. The Pluto development is shown in Figure 14.

Figure 14: Pluto LNG Development Scheme



Source: Woodside

The Pluto LNG project, located some 5 km from the Karratha Gas Plant, currently consists of a single train, 5 MTPA, liquefaction facility together with up to 40 TJ/day of domestic gas supply consisting of 25 TJ/day from Pluto and 15 TJ/day from LNG trucking. Under the Scarborough field development, an additional train will be added to the Pluto LNG plant (Section 1.5).

The Pluto offshore facilities and the onshore LNG plant have been in service since end 2012, with one full shutdown apparent at the end of 2019 for nearly 8 weeks and shorter shutdown/turnarounds (~2 week) late 2013 and 2015. This level of planned shutdown interval is normal for a facility of this nature. Facilities reliability was recorded at 97.2% in 2020.

The Pluto LNG facility provides gas sales access to the world LNG market, and is also linked to the Western Australian domestic market via the Dampier to Bunbury natural gas pipeline. Pluto LNG is located next to, and is interconnected with, the KGP, allowing some degree of capacity sharing between the two liquefaction facilities. The Pluto LNG site has expansion space available for additional train(s), with Train 2 currently under construction to support the Scarborough development.

Woodside plans to commence D&R planning 3 to 4 years prior to the forecast end of field life. D&R expenditure extends over 9 years (upstream) to 13 years (downstream), realistic phasing for a D&R project of this scale.

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering CAPEX, OPEX, and D&R costs for the Pluto offshore and onshore operations from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline has accepted Woodside's detailed cost forecasts as reasonable.

Gross CAPEX for further development activities relating to the Pluto Reserves case is estimated to be US$1,300 MM.

1.4.4 Resources Estimates

Reserves attributed to Pluto, Xena and Pyxis assume a minimum trunkline turn-down of 250 MMscfd.

Contingent Resources are attributed for incremental volumes estimated to be recoverable by reducing the trunkline turn-down rate from 250 MMscfd to 100 MMscfd (Development Pending) and for four infill wells (Development Unclarified) (Table 20).

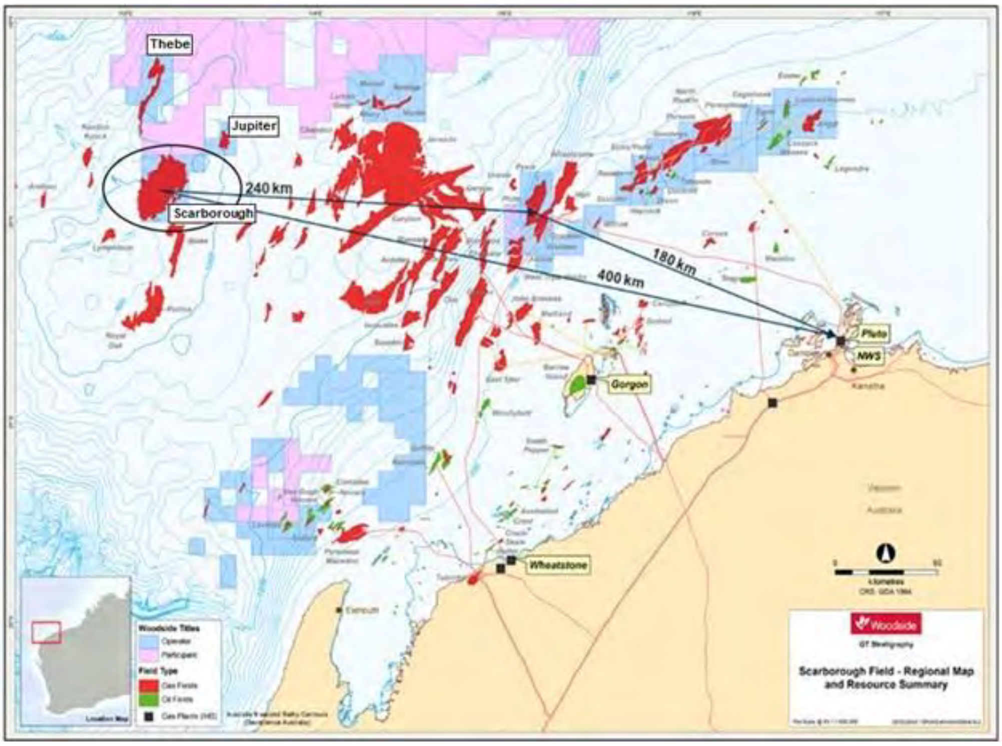
Table 20: Gross Greater Pluto Contingent Resources as at 31st December 2021

Project	Gas (Bscf)	Condensate (MMBbl)	Development Status
Tail gas to 100 MMscfd	59	0.7	Pending
TR30, TR27 and Xena TR34 Infill wells	198	2.3	Unclarified
Pluto TR27.2 Channel Infill well	59	0.7	Unclarified
Total	**316**	**3.7**	

1.5 Scarborough LNG

Woodside and BHP Petroleum have interests in the Scarborough Field, situated predominantly in leases WA-61-L (previously WA-1-R) and WA-62-L (previously WA-62-R) approximately 375 km from Karratha in water depth of ~1,400 m (Figure 15), and in the two satellite fields Jupiter and Thebe. In February 2020 an agreement was reached between Woodside and BHP Petroleum to align their participating interests across the two titles, resulting in Woodside holding a 73.5% interest and BHP Petroleum holding the remaining 26.5% interest in each.

Figure 15: Scarborough, Jupiter and Thebe Field Location Map



Source: Woodside

1.5.1 Field Description

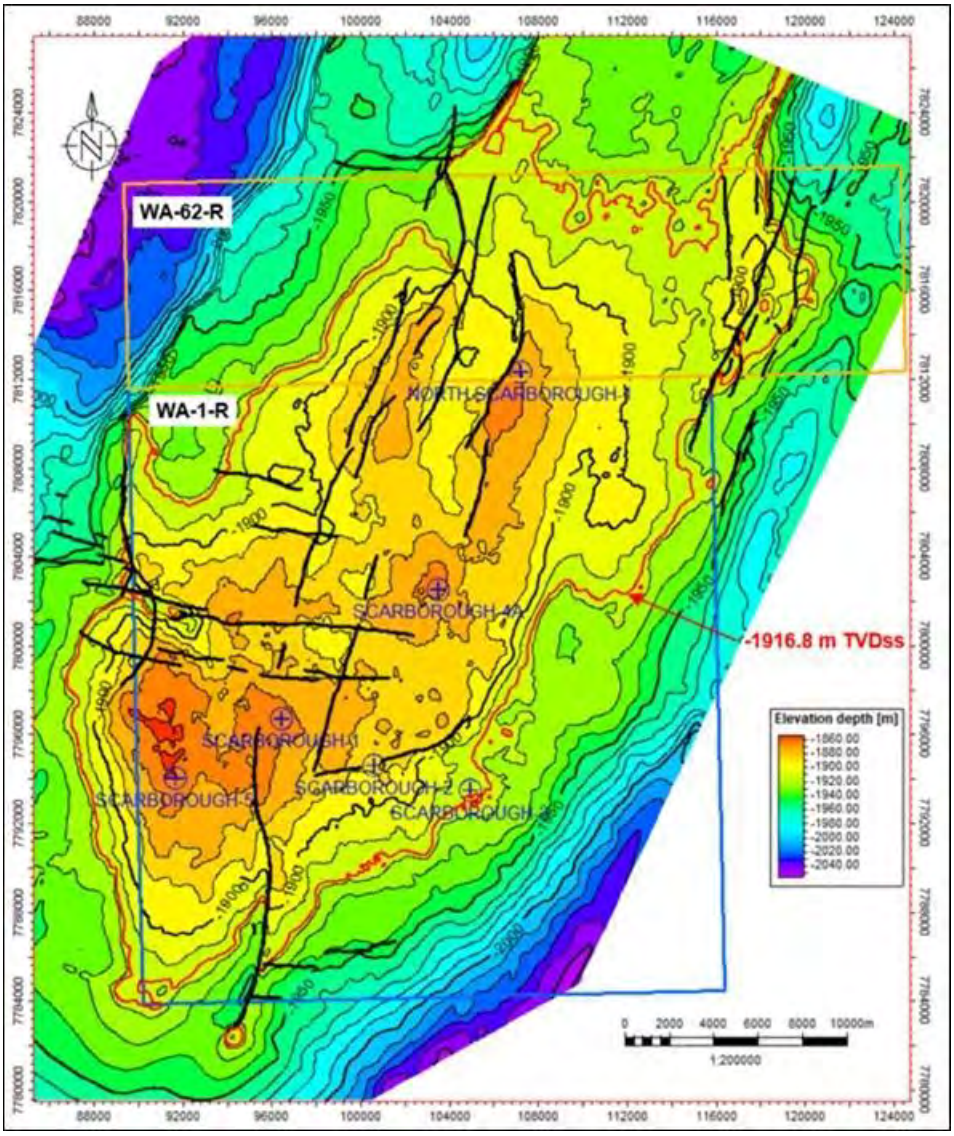
The field is formed of a four-way dip closed NNE trending anticline and was discovered in 1979 with the drilling of the Scarborough-1 exploration well, which intersected high quality gas bearing sandstones with a gross column of approximately 110 m. An appraisal well, Scarborough-2 was drilled in 1996 before the first 3D seismic survey covering the field was shot in 2004. Four subsequent appraisal wells were drilled on Scarborough between 2004 and 2021. Field appraisal confirmed a field wide GWC and a relatively uniform gas composition.

The reservoir interval is formed of the Early Cretaceous Lower Barrow Group. The provenance of the Scarborough Field reservoirs is the Australian craton with sediments transported via the prograding Barrow Group Delta system to a shelf break located approximately 50 km to the south of the Scarborough Field.

The reservoir sands consist of a three-tiered, basin floor turbidite fan. The Lower Fan unit (K17.04, K17.02, K16.9, K16.7 and K16.4) is a high-quality sand with high NTG and contains the majority of the GIIP. It is formed of amalgamated turbidite, channel and lobate sandstone deposition and represents the beginning of the waning of the Lower Barrow Group system. The overlying Middle (K17.1, K17.06) and Upper Fans (K17.3, K17.2) are more localized and discrete with lower NTG and represent the continued waning and backstepping of the depositional system.

Cores from Scarborough wells show poorly consolidated, fine to medium grained sands with minor clay components. The Lower Fan reservoir sands have porosity of 23 to 40% and permeability of 0.65 to 9 D. The Upper and Middle Fan sands have core porosity of 23 to 37% and permeability of 0.5 to 7.5 D. Figure 16 shows a depth structure map of the K17.06 reservoir interval.

Figure 16: GaffneyCline Depth Structure Map of K17.06



GaffneyCline generated surface attributes for the reservoir units UF-K17.3, K17.2; MF-K17.1, K17.06 and LF-K17.04, K17.02, K16.9, K16.7, K16.4, which were utilised to evaluate uncertainty in GRV of the basin floor sands. Areal polygons were combined with the depth surfaces to estimate overall ranges of uncertainty in GRV. Reservoir parameters from GaffneyCline's petrophysical analysis (NTG, porosity, water saturation) were used to make probabilistic and deterministic estimates per reservoir unit. The GIIP for each fan was subsequently estimated as an average between the probabilistic and deterministic outputs. GaffneyCline's estimates of GIIP are given in Table 21.

Table 21: GaffneyCline's Estimates of GIIP for the Scarborough Field

Fan	Reservoir	GIIP (Bscf)	
		P90	P50
Upper	K17.3	148	321
	K17.2	241	322
Middle	K17.1	196	286
	K17.06	1,924	3,082
Lower	K17.04	2,915	3,643
	K17.02	6,773	8,225
	K16.9	1,730	2,105
	K16.7	74	91
	K16.4	78	95

Nearby offset wells, Jupiter-1 and Thebe-1 are the discovery wells of additional gas accumulations located to the NE and N of Scarborough respectively. The Jupiter gas accumulation is contained within the youngest section of the Triassic Mungaroo Formation. The Jupiter-1 well penetrated 16.3 m of net gas pay with average porosity of 23.6%. The reservoir consists of argillaceous sandstones, silts and clays. The Jupiter structure is located at the culmination of a plunging Triassic tilted fault block which is onlapped and overlain by the Upper Dingo Claystone which acts as the lateral and top seal for the field. A well-defined flat spot is observed on seismic data, coincident with a depth between the lowest known gas at 1,925 mss and the highest known water at 1,930 mss, and this is interpreted to be the GWC.

The Thebe gas accumulation is contained within fine-grained argillaceous sandstones of the Mungaroo Formation. The Thebe-1 well was drilled in 2007 and discovered gas at the top of the Mungaroo with a net pay section of 51.2 m and average porosity of 27.1%. An appraisal well, Thebe-2 was drilled in 2008 to test the northern extension of the field. The field is formed of two connected foot-wall accumulations developed by two offset, SW-NE trending en-echelon faults. The fault blocks are onlapped and overlain by the Dingo Formation which forms the top and lateral seal for the reservoir. The field GWC is defined at 2,317 mss based on pressure data and is consistent with a field wide flat spot associated with amplitude brightening in the seismic data.

Both the Thebe and Jupiter Fields offer future development opportunities to be used as backfill into the Scarborough FPU. GaffneyCline has reviewed probabilistic GIIP estimates provided by Woodside (Table 22).

Table 22: GaffneyCline's Estimates of GIIP for the Jupiter and Thebe Fields

Field	GIIP (Bscf)	
	P90	P50
Jupiter	379	791
Thebe	2,500	2,970

1.5.2 Development Plan and Production Forecasts

Scarborough

The Scarborough dry gas field will be developed with 13 subsea wells drilled in two phases, tied back to a semisubmersible hull FPU. GaffneyCline estimated recoverable volumes of gas by multiplying the GIIP estimates with gas recovery factors derived from sensitivities run on the dynamic simulation model. Low estimate and Best estimate estimates of gross technically recoverable volumes of gas are 7.6 Tscf and 11.9 Tscf respectively. GaffneyCline's production forecasts are scaled from the Woodside forecasts to honour the GaffneyCline gas recoveries. The production profiles used by GaffneyCline for evaluation reflect ullage availability, venture-agreed allocated liquefaction capacity and estimated field deliverability over time. The forecasts show production starting in 2026 and ramping up to maintain rates between 1,300 MMscfd and 1,600 MMscfd from 2027 to 2034 in the Low estimate and to 2041 in the Best estimate before declining.

Thebe

The Thebe dry gas field will be developed to backfill production from the Scarborough gas field, and development will comprise eight vertical subsea wells, tied back to the Scarborough FPU.

Woodside estimates recoverable volumes using probabilistic estimates of GIIP and a recovery factor range from sensitivities run on the dynamic model. Gas recovery is limited by water breakthrough. GaffneyCline reviewed the volumetric estimates and recovery factors in order to formulate its independent opinion and found Woodside's estimates of recoverable volumes to be optimistic. Table 23 shows GaffneyCline's estimates of GIIP and 2C Contingent Resources (Development Pending).

Table 23: GaffneyCline's Estimates of GIIP and Contingent Resources for the Thebe Field as at 31st December 2021

Parameter	Units	Best Estimate
GIIP	(Bscf)	2,970
RF	(%)	35
Gross 2C Contingent Resources	(Bscf)	1,040

Jupiter

The Jupiter dry gas field will be developed to backfill production from the Scarborough and Thebe gas fields, and development will comprise two vertical subsea wells, tied back to the Scarborough FPU. Subsurface studies to mature the subsurface understanding of Jupiter are planned for 2021. This will include reprocessing the existing seismic data using Full Waveform Inversion (FWI) and updating the seismic interpretation for any new insights.

Woodside estimates recoverable volumes using a recovery factor range derived from dynamic models. Gas recovery is limited by water breakthrough. GaffneyCline reviewed the volumetric estimates and dynamic models in order to formulate its independent opinion and found Woodside's estimates of recoverable volumes to be optimistic. Table 24 shows GaffneyCline's estimates of GIIP and Contingent Resources (Development Pending).

Table 24: GaffneyCline's Estimates of GIIP and Contingent Resources for the Jupiter Field as at 31st December 2021

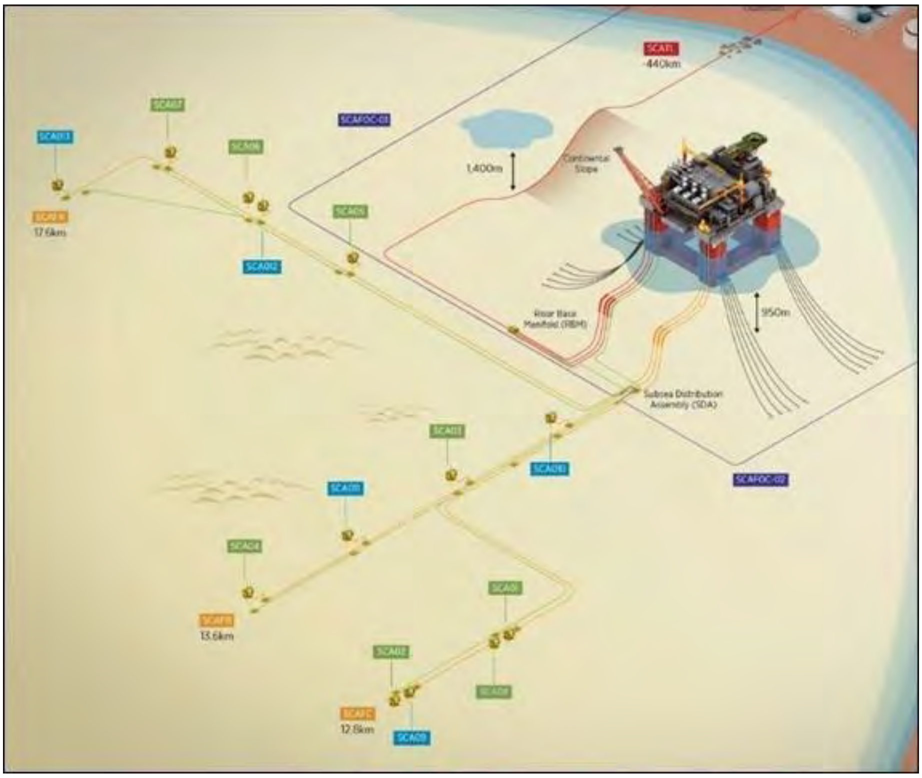
Parameter	Units	Best Estimate
GIIP	(Bscf)	791
RF	(%)	35
Gross 2C Contingent Resources	(Bscf)	277

1.5.3 Facilities and Cost Estimates

The Scarborough field will be developed with subsea wells in some 1,400 m water depth, tied back to a semisubmersible floating production unit (FPU) moored in 950 m water depth. The subsea development is planned for up to 13 wells, although the facility will commence production from a first phase of eight high-rate wells. Gas will be dehydrated and compressed on the FPU (capacity 1,750 MMscfd), and transported in a 32"/36" pipeline, 430 km to shore to the Pluto LNG plant at Karratha. The offshore development concept is shown in Figure 17.

Scarborough gas will be liquefied in a new Train 2 expansion to the existing Pluto LNG plant. Pluto Train 2 will have a capacity of 5 MTPA LNG and up to 225 TJ/day domestic gas supply. An additional 2 to 3 MTPA can be liquefied using capacity in Pluto Train 1, providing an overall deliverability of up to 8 MTPA LNG from the Scarborough field. To further optimize the utilization of installed capacity, a 5 km interconnector pipeline has been installed to link the Pluto and Karratha Gas Plant (KGP) LNG facilities, which can also deliver to the Western Australia domestic gas market through the Dampier to Bunbury pipeline. An overview of the Pluto Train 2 development is shown in Figure 18.

Figure 17: Scarborough Offshore Development Concept



Source: Woodside

Figure 18: Pluto Train 2 Overview

Source: Woodside (note as of November 2021, the development marked “proposed” is approved).

A Final Investment Decision (FID) was taken in November 2021, with first gas planned 48 months after FID and the first LNG cargo 6 months thereafter. Woodside has provided current, FID-ready capital and operating cost estimates for the initial phase of the Scarborough development. GaffneyCline has reviewed and accepted the development costs, with minor adjustments for consistency with its production profiles.

The Scarborough offshore development is designed with a fibre optic cable link to the coast, allowing the facility to be monitored and operated from shore. The offshore FPU is designed to an overall reliability and availability target of at least 97%.

Scarborough end of field life is not expected to occur before 2050, so D&R planning is at a conceptual level. Woodside's D&R estimate appears to be based on current good industry practice, i.e. full removal of the FPU and all subsea flowlines, trunkline and equipment. This is a reasonable basis and is accepted by GaffneyCline.

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering CAPEX, OPEX, and D&R costs for the offshore Scarborough and onshore Pluto Train 2 operations from 2021 to the end of field life and completion of D&R activities. GaffneyCline has accepted Woodside's detailed cost forecasts as reasonable. Note that the construction costs of Train 2 and the offshore development have been substantially covered by contract, limiting the escalation risk.

Gross CAPEX for development of the Scarborough Reserves case is estimated to be US$6,213 MM.

A substantial part of Scarborough's costs are incurred as tariffs paid by the Scarborough JV to the downstream Pluto Train 2 venture, for LNG and Domestic gas liquefaction and processing services. GaffneyCline has reviewed these tariff flows and adjusted to an RT2022 basis and GaffneyCline's production profiles.

1.5.4 Resources Estimates

Reserves are attributed to the Scarborough field and Contingent Resources (Development Pending) are attributed to Thebe and Jupiter.

1.6 WA-404-P Permit

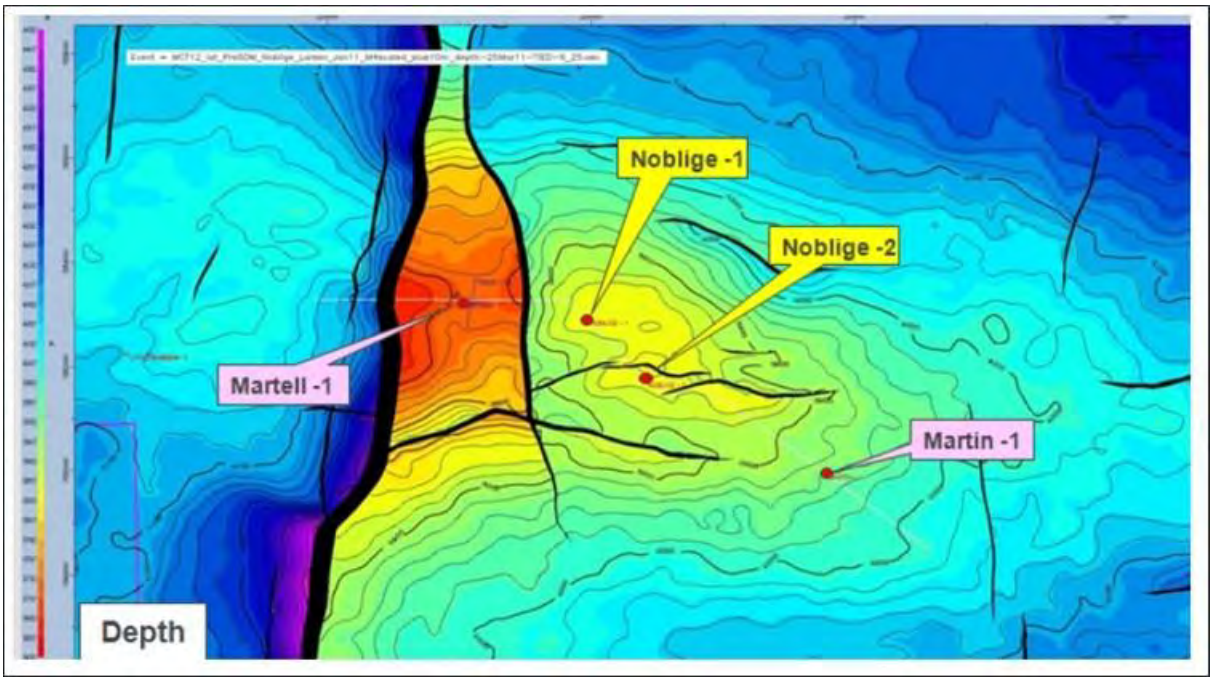
The WA-404-P asset encompasses undeveloped discoveries Remy, Martell, Martin, Noblige and Larsen Deep, all located within the WA-404-P permit, offshore Western Australia, approximately 100 km northwest of the Pluto Field in water depth of 1,500 m (Figure 12). The permit was awarded in 2007, with 10 commitment exploration wells drilled since 2009 and Woodside has a 90% interest. In addition to the commitment wells, an appraisal well, Noblige-2, was drilled in August 2011.

Development of these discovered gas accumulations is conceptually planned to backfill Pluto LNG.

1.6.1 Field Description

Martell-1 well was drilled in 2009 to target the Upper Mungaroo Formation within a constrained fault block (Figure 19). The well encountered gas from 2,750 mTVDss, penetrating a 113 m gas column. The interval has multiple layers with variable NTG. The reservoir is good quality with mean porosity of 23% and permeability of 900 mD. The Low, Best and High estimates of GIIP are 225, 384 and 559 Bscf.

Figure 19: Depth Structure Map of Mungaroo Reservoir showing Locations of WA-404-P Main Discoveries



Source: Woodside

The Larsen Deep gas accumulation was discovered by Larsen Deep-1 well, drilled in 2010. Gas was encountered within a sandstone of the Mungaroo Formation, at a depth of around 4,600 mTVDss. Three gas samples were recovered using a wireline formation tester tool. The discovered accumulation is thought to be trapped stratigraphically in a channel feature, as shown by amplitude response in the seismic data. The Low, Best and High estimates of GIIP are 19, 65 and 119 Bscf.

The Noblige-1 well was drilled in 2010 to target the Mungaroo Formation within a four-way dip closure. The well penetrated gas at multiple levels between depths of 3,280 m and 4,148 mTVDss. Noblige-2 appraisal well was drilled in 2011 to assess the range of reservoir quality away from the seismic ‘bright spot’ area. The well encountered three undrilled reservoirs and obtained downhole samples. The Low, Best and High estimates of GIIP are 364, 615 and 1,007 Bscf.

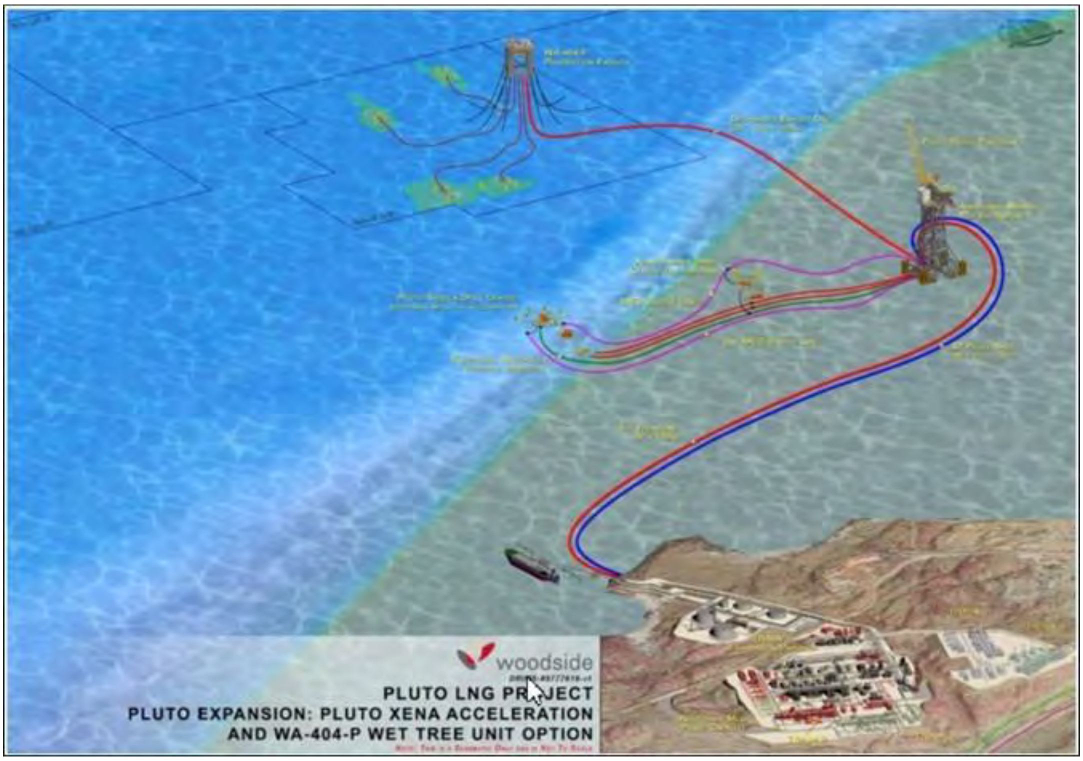
The Remy-1A well was drilled in 2010 in a horst block at the Mungaroo Formation level. The well encountered two main gas bearing intervals between 4,100 and 4,500 mTVDss. The Low, Best and High estimates of GIIP are 47, 130 and 358 Bscf.

Martin Field was discovered in 2011 by the drilling of Martin-1, which was targeting the Mungaroo Formation within a three-way dip closed structure. The well intersected a gas column at 4,623 mTVDss, with 83.6 m gross pay. The Low, Best and High estimates of GIIP are 108, 372 and 635 Bscf.

1.6.2 Development Plan and Production Forecasts

The fields are all undeveloped. Figure 20 shows the conceptual development plan comprising a seven well wet-tree tieback to a conventional semi-submersible substructure and topsides, which is tied back subsea some 100 km to the Pluto trunkline. Due to the higher development costs, WA-404-P is only considered as a longer-term Pluto supply option with timing to meet deliverability requirements in approximately 2029.

Figure 20: WA-404-P Development Plan



Source: Woodside

Table 25 lists the potentially recoverable volumes for projects within WA-404-P, which are classified as Contingent Resources (Development Not Viable).

1.6.3 Resources Estimates

Contingent Resources for the WA-404-P permit are shown in Table 25.

Table 25: Gross WA-404-P 2C Contingent Resources by Discovery as at 31st December 2021

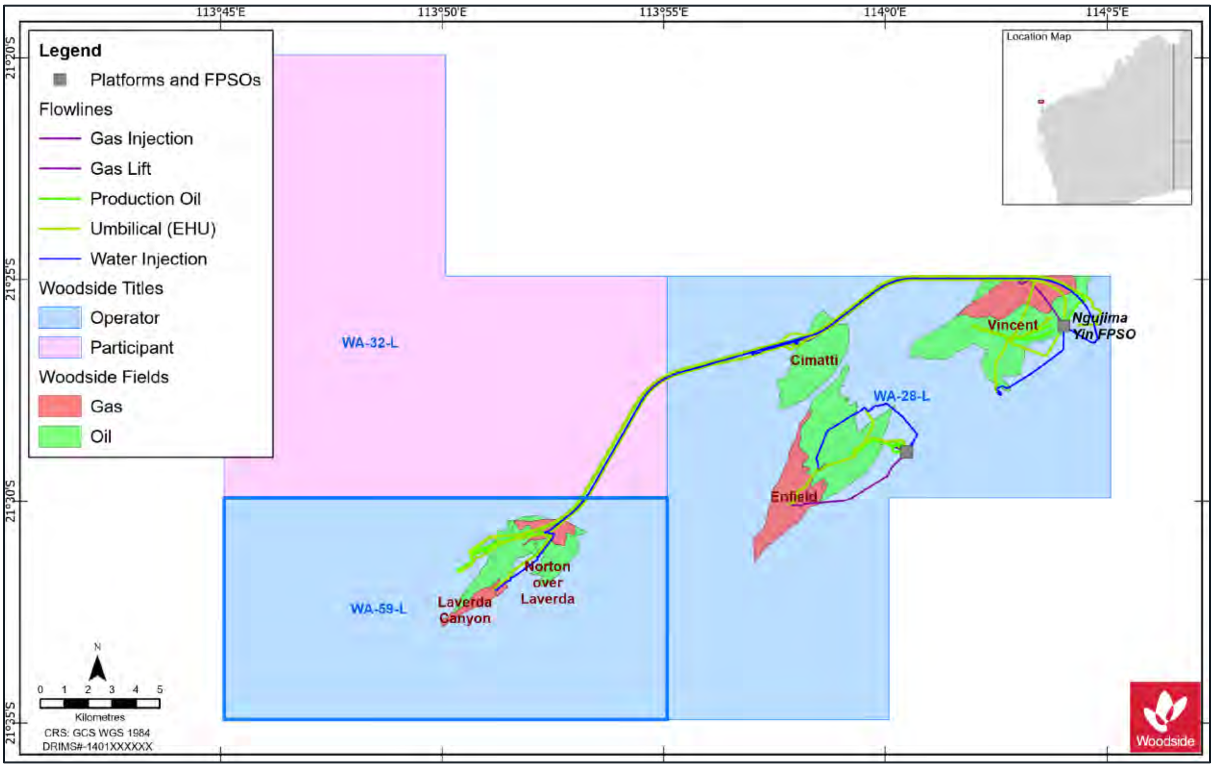
Field	Gas (Bscf)	Condensate (MMBbl)	Development Status
Larsen	41	0.4	Not Viable
Remy	37	0.7	Not Viable
Martel	244	8.9	Not Viable
Martin	256	3.6	Not Viable
Noblige	428	5.9	Not Viable
Total	**1,006**	**19.5**	

1.7 Greater Enfield Oil and Vincent

Greater Enfield consists of the following fields: Cimatti, Laverda Canyon and Norton over Laverda. Greater Enfield and the Vincent field are on production via the Ngujima-Yin FPSO. The Enfield oil field itself ceased production in 2018. Vincent and Cimatti are located within the WA-28-L permit, at 380 m and 500 to 580 m water depth respectively. Laverda Canyon and Norton over Laverda are located within WA-59-L permit at approximately 800 m water depth. Woodside has 60% interest in both permits. The fields are located about 40 km off the North West Cape of Western Australia (Figure 21). Additionally, in the Laverda area there are the undeveloped discoveries Laverda West, Laverda East, Opel and Norton Central. The Enfield field produced 81 MMBbl, but is no longer in production and is being prepared for abandonment and decommissioning.

The Greater Enfield fields are located in the Exmouth Sub-basin of the Northern Carnarvon Basin. The reservoirs of these fields are the Late Jurassic Macedon Sandstone and the Early Cretaceous Lower Barrow Group.

Figure 21: Greater Enfield Asset Location Map



Source: Woodside

1.7.1 Field Description

The Vincent-1 well was drilled in 1998, followed with an appraisal well, Vincent-2, in 1999. The Vincent accumulation comprises high quality sandstone units of Late Jurassic-Early Cretaceous age Lower Barrow Group. The hydrocarbon (oil with a gas cap) was found in a northeast-southwest trending low relief, three-way dip closure against a fault. Immediately to the north in the neighbouring permit, the Van Gogh Field was discovered in the same reservoir in 2003. However, it was subsequently found that the two fields are separate, likely due to stratigraphic barrier, and they have not been unitized. The reservoir is of high quality with average porosity of 29% and average permeability of 4.5 D. The Vincent field is an oil rim reservoir with a gas cap of approximately 160 Bscf and is supported by a strong bottom water/edge water aquifer.

The Cimatti field was discovered by the Cimatti-1 well in 2010. It was appraised by Cimatti-2, a sidetrack well drilled immediately after the first well. Cimati-1 targeted bright seismic amplitude at the Macedon Sandstone level and encountered 14.7 m of oil pay in a sandstone reservoir. The appraisal well encountered 5.9 m of oil pay 360 m to the northwest of the first well. The Cimatti structure is an elongated, northeast-southwest trending fault block at the east of the Enfield field. The reservoir was deposited in deep marine channels, and consists of high quality, clean, medium grained sandstone. The oil in Cimatti is relatively light compared to offset fields, with density of 31°API and viscosity of 0.5 cP, and has a favourable mobility ratio for water flooding.

The Laverda Canyon Field was discovered by the Laverda-1 well, drilled in 2000, which encountered 64 m of oil with 9 m of gas cap in the Macedon Sandstone reservoir at a depth of around 1,980 mTVDss. The Macedon Sandstone in the Laverda Canyon Field is deposited as channel fill within a marine canyon. The reservoir consists of two excellent quality sandstone packages: a high NTG, 8 to 14 m thick Upper Sand with permeability of 3 to 4 Darcy, and a more stratigraphically complex, lower NTG, up to 80 m thick Lower Sand, with an average permeability of 1 to 2 Darcy. The Lower Sand has multiple cut and fill events evident on seismic and is overlain by 15 to 20 m of sandy siltstone. It is a low relief structure and contains a 60 m oil column, which is of intermediate gravity, similar to that in offset fields Enfield and Stybarrow.

The Norton over Laverda Field was drilled in 2011 by Laverda North-1 and -2 which encountered hydrocarbons in the Early Cretaceous sandstone of the Lower Barrow Group. The wells also encountered oil in the Macedon Sandstone to the north of Laverda Canyon. Another well, Laverda East-1 which was drilled in 2011 also penetrated Norton over Laverda and found hydrocarbon in the Cretaceous sandstone. The Norton over Laverda oil and gas pool in the Lower Barrow Sandstone is trapped in a three-way dipping structure against a fault at its northern side. The reservoir is composed of thin (15 to 20 m) alternating fluvial and tide-dominated lower delta plain and estuarine sandstones of multi-Darcy permeability.

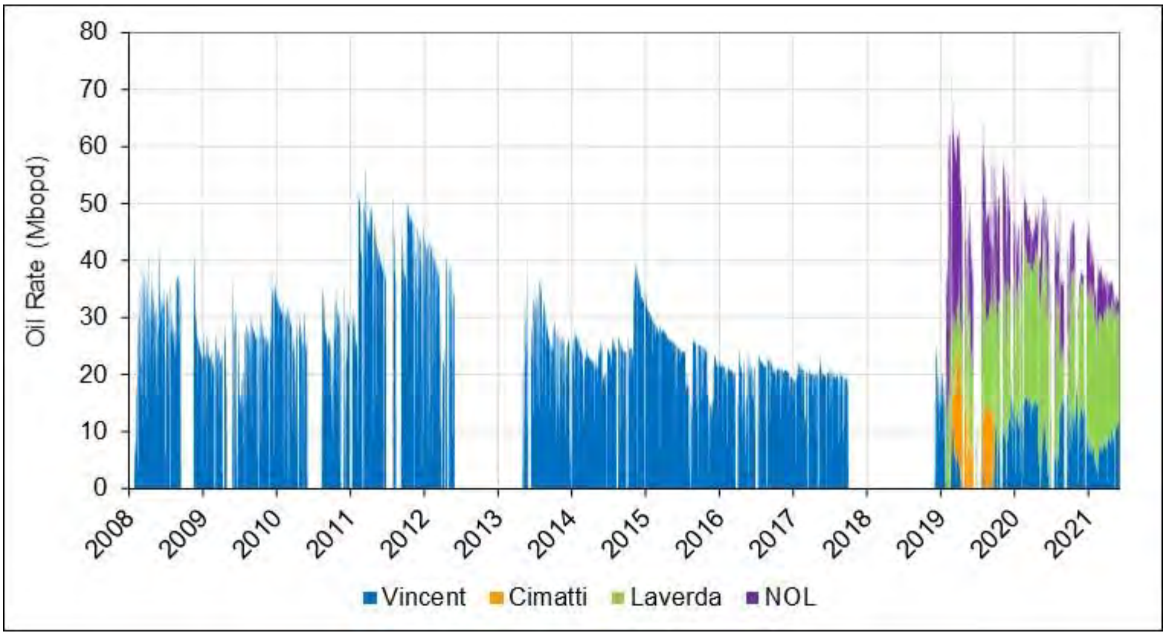
The Enfield oil field ceased production in 2018, having been developed with two gas injectors, eight water injectors and eight oil producers in the Macedon Sandstone Member. The remaining project is to abandon and decommission this field.

Laverda West, Laverda East, Opel, Norton Central and Skiddaw are undeveloped oil and gas fields located around the Laverda Canyon oil field, with relatively small estimates of recoverable volumes.

1.7.2 Field Development and Production Profiles

Vincent is developed with thirteen horizontal wells (seven bi-laterals and six tri-laterals). Two water injection wells are used for water disposal and there is one vertical gas injector for disposal of surplus gas. Production commenced in 2008 to the Ngujima Yin FPSO. Cimatti is fully developed with one horizontal production well and three water injection wells to keep the reservoir pressure above the bubble point. The Laverda Canyon Field is fully developed by two producer wells and three water injection wells. The Norton over Laverda Field is developed by three tri-lateral oil producing wells. The strong natural aquifer provides good pressure support to Norton over Laverda and the reservoir pressure remains above the bubble point. Cimatti, Laverda Canyon and Norton commenced production in 2019 via the Ngujima Yin FPSO. Figure 22 shows the historical production from the four fields.

Figure 22: Historical Production of the Vincent and Greater Enfield Fields



GaffneyCline conducted performance analysis, decline curve analysis and analogue-based recovery factor checks to review Woodside's estimates and production forecasts for the Vincent and Greater Enfield fields. Best estimate production forecasts were accepted for all the fields except Cimatti, for which GaffneyCline created its own profile. Low estimate production profiles were accepted for Vincent and the Laverda Canyon, and GaffneyCline created its own for Cimatti and the Norton over Laverda fields.

Figure 23 shows the combined technical forecasts for the Vincent and Greater Enfield projects and Table 26 lists the recoverable volumes. Termination of production forecast in 2028 is driven by the planned end of Vincent facilities' life. Volumes associated with a possible extension to 2038 are classified as Contingent Resources.

Figure 23: Greater Enfield and Vincent Technical Forecasts (Developed)

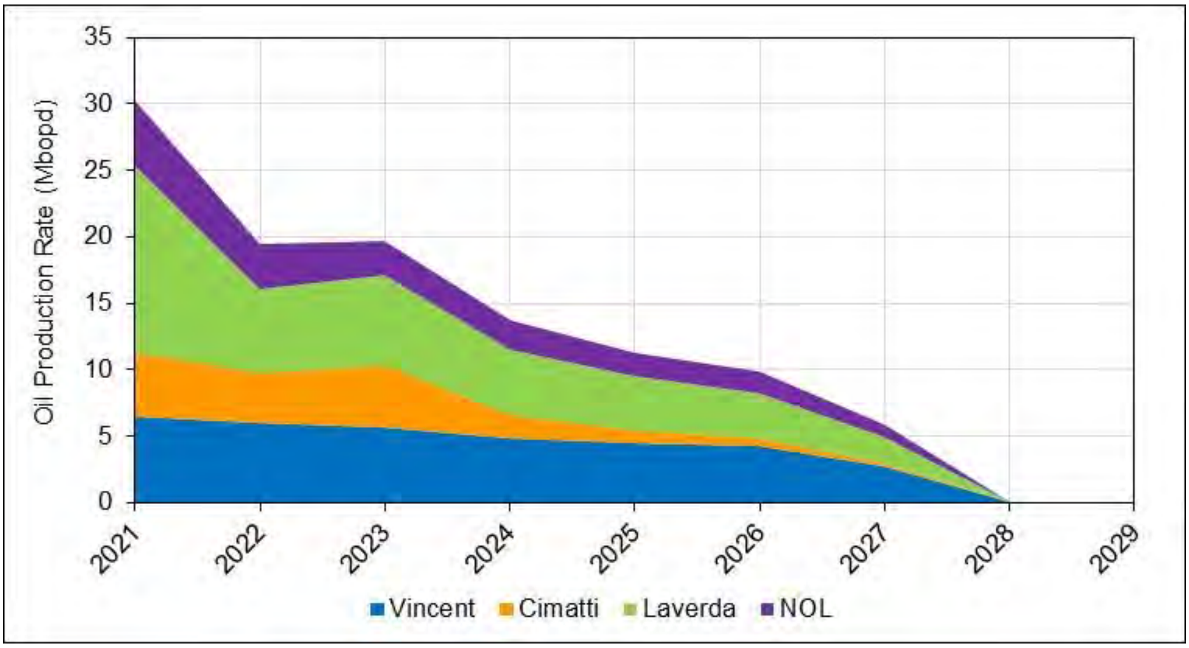


Table 26: Greater Enfield and Vincent Gross Technically Remaining Recoverable Volumes as at 31st December 2021

Field	Cumulative Production (MMBbl)	Remaining Recoverable Oil (MMBbl)	
		Low	Best
Vincent	78.1	8.4	12.5
Cimatti	2.2	3.3	6.2
Laverda Canyon	15.0	13.4	15.1
Norton Over Laverda	8.0	3.1	6.3

Note:

1. Estimates to planned end of facilities' life in 2028; no economic cut-off has been applied.

1.7.3 Resources Estimates

Reserves are attributed to future production from the four producing fields.

Additionally Contingent Resources are attributed to various projects, classified as Not Viable because the volumes are currently considered too small for commercial development and there are currently no plans to develop them (Table 27).

Table 27: Greater Enfield Gross Contingent Resources as at 31st December 2021

Field	2C Contingent Resources	
	Gas (Bscf)	Oil (MMBbl)
Vincent	-	17.7
Cimatti	-	0.7
Laverda Canyon	-	9.3
Norton over Laverda	-	8.2
Laverda West	54.0	6.8
Laverda East	0.8	2.9
Opel	17.2	3.0
Norton Central	-	4.4
Skiddaw	-	0.6
Totals	**72.0**	**53.6**

1.7.4 Facilities and Costing

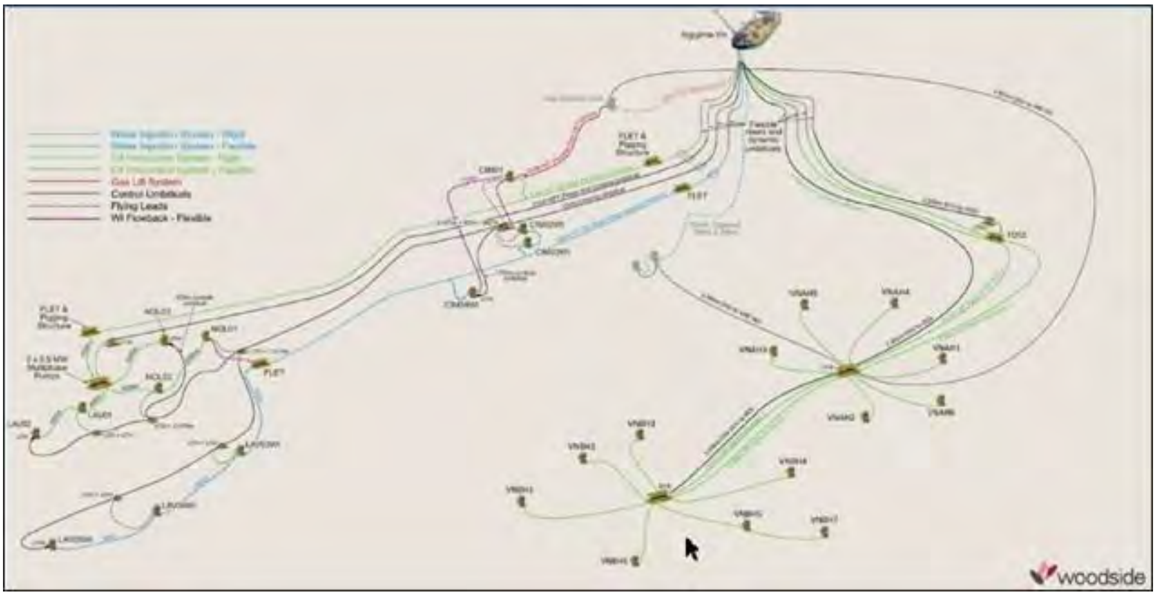
The Ngujima-Yin FPSO is located over the Vincent field in 350 to 400 m water depth. Development commenced with the Vincent Field, with the other fields tied back via a 31 km x 16” flowline. The FPSO has a design production capacity of 120 Mbopd, 155 Mbwpd and 250 Mblpd (gross liquids). Production is currently limited by water production, clean-up and disposal capacity.

The FPSO provides oil processing, water injection supply and injection, gas lift and gas injection. Since installation, the FPSO has been shut down for scheduled inspection and refurbishment in 2012 and 2018. The next scheduled turnaround is an 82-day shutdown planned for 2023 (typically 5-year intervals). An overview of the Greater Enfield development is shown in Figure 24.

Limited information is available on the facilities integrity of the FPSO or subsea system, however the Operator notes concern with “facilities availability, particularly water injection system and multiphase pumps”.

The Ngujima Yin FPSO has been in service since early 2008 with production outages every five years (2013 and 2018/19) for planned dry dock and vessel inspection. In total, the facility has been offline for 25 months of its 162 month service life, or 84.5% overall uptime. Reliability in 2020 was somewhat better, at 88.4%, however a planned 5-yearly dry dock and inspection will result in 5 months planned downtime in 2023.

Figure 24: Greater Enfield Development Plan



Source: Woodside

The Ngujima Yin FPSO production system allows independent oil export, and is currently self-sufficient in fuel gas.

Current operational planning is focused on facilities uptime and integrity, with limited near-term D&R activity. Woodside has, however, developed a phased D&R plan commencing three years prior to the end of field life and extending over 8 years. GaffneyCline considers this a reasonable planning.

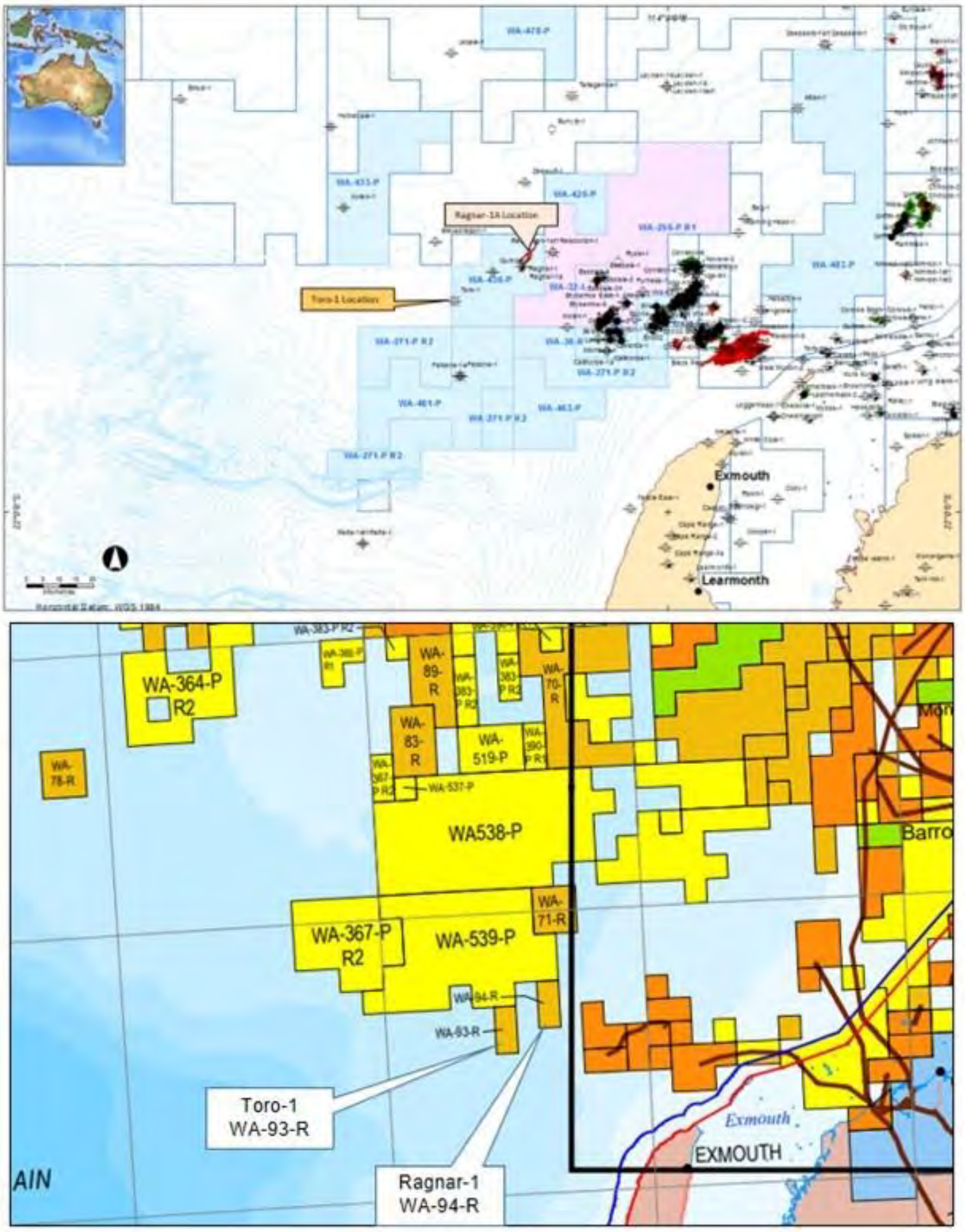
GaffneyCline has reviewed a detailed cost forecast provided by Woodside covering CAPEX, OPEX, and D&R costs from 2021 to the end of field(s) life and completion of D&R activities. GaffneyCline accepted Woodside's CAPEX and OPEX cost forecasts as reasonable. D&R cost estimates, however, were materially increased in our review to reflect current D&R scope and the full exploration, appraisal and production well count remaining.

Gross CAPEX for further development activities related to the Greater Enfield Reserves case is estimated to be US$149 MM.

1.8 Ragnar and Toro (WA-93-R and WA-94-R Leases)

The Ragnar-1 and Toro-1 wells were drilled in the WA-430-P permit in 2012 and 2014, respectively. In April 2020, when WA-430-P was surrendered, two smaller retention lease areas were carved out around the two assets: WA-93-R around Toro and WA-94-R around Ragnar. Woodside has 70% WI in each permit. These permits will expire in 2025, and Woodside is working to identify viable development options for them. Figure 25 shows the locations of the wells and the location of the two new leases. Ragnar and Toro are located about 40 km from the Greater Enfield assets. Geologically the wells were drilled in the Exmouth Sub-basin.

Figure 25: Location Maps of Toro and Ragnar (upper), WA-93-R and WA-94-R (lower)



Source: Woodside (upper), Australian National Petroleum Titles Administration - NOPTA (lower)

1.8.1 Field Description

Ragnar-1 encountered 75 m of gross gas column in the Triassic Mungaroo Formation sandstone units. Low, Best and High case estimates of GIIP for Ragnar are 241, 349 and 486 Bscf. The Ragnar structure is estimated to contain a mean 'on-block' recoverable raw gas volume of 277 Bscf.

Toro-1 was drilled approximately 22 km southwest of Ragnar in 1,160 m water depth as a follow-up to the Ragnar-1 discovery. The target was the Triassic Mungaroo sandstone reservoir in a two-way dipping horst block. The well encountered 151 m of gross gas column at 3,088 mss. The reservoir has 11 to 21% porosity and 25 to 200 mD permeability. A total of 9 fluid samples were acquired from two depths. Gas compositional analysis indicates an average CGR of 23 Bbl/Mscf. Non hydrocarbons make up an average of 6 mole%.

Low, Best and High case estimates of GIIP for Toro are 160, 234 and 326 Bscf. The Toro structure is calculated to contain a mean ‘on-block’ recoverable raw gas volume of 154 Bscf, not including inert components (CO_2, N_2). Approximately 3% of the structure is interpreted as lying outside the permit boundary.

1.8.2 Field Development Plan and Production Profiles

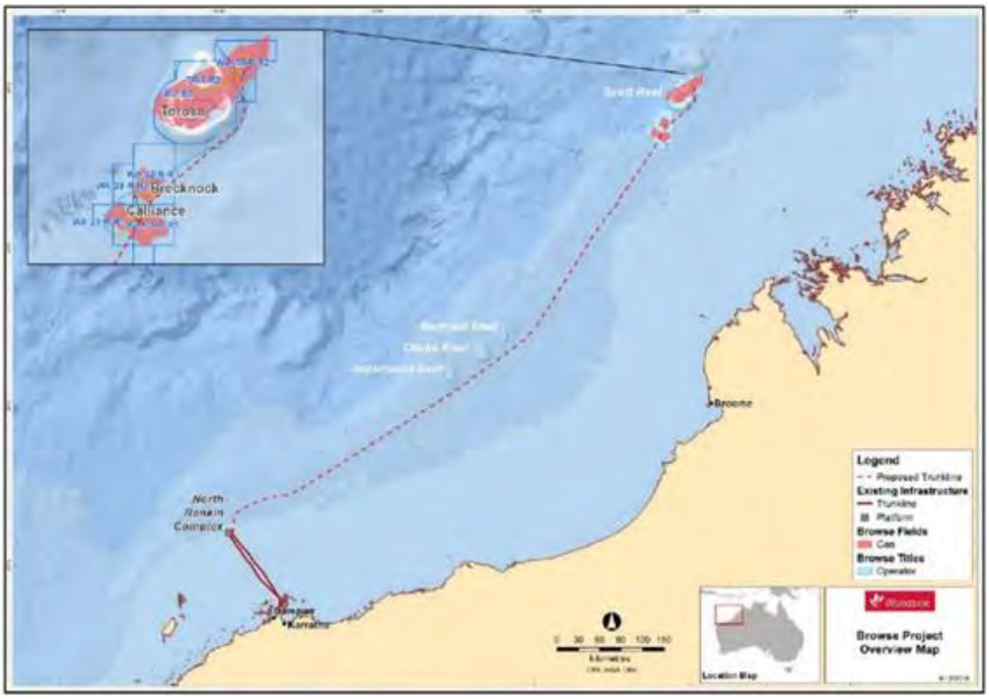
An integrated field development study of the Ragnar Field was conducted in 2013 to investigate the opportunity to produce Ragnar via a subsea pipeline tied back to the Greater Laverda project. However, the volumes were considered too small to justify the plan.

The Ragnar and Toro Fields are currently viewed as technically and commercially immature due to their small volumes and distance from infrastructure. Gross 2C Contingent Resources (Development Not Viable) of 385 Bscf gas and 3.2 MMBbl condensate are attributed to a potential development.

1.9 Browse (Torosa, Brecknock, and Calliance)

The undeveloped Torosa, Brecknock, and Calliance gas fields (collectively the Browse development) lie in the offshore Browse Basin, 425 km north of Broome, Western Australia (Figure 26). Gas was discovered at Torosa in 1971, Brecknock in 1979, and Calliance in 2000. Seventeen wells have been drilled across the fields, with twelve drilled since the petroleum retention leases (RLs) were first granted in 2003. Retention leases WA-28-R to WA-32-R (five) are in Commonwealth waters with two other leases in Western Australia State jurisdiction (TR/5 and R2). The Calliance and Brecknock fields lie in water depths of 500 to 700 m, while the Torosa field lies under Scott Reef with water depths varying from 0 to 475 m.

Figure 26: Browse Asset Location Map



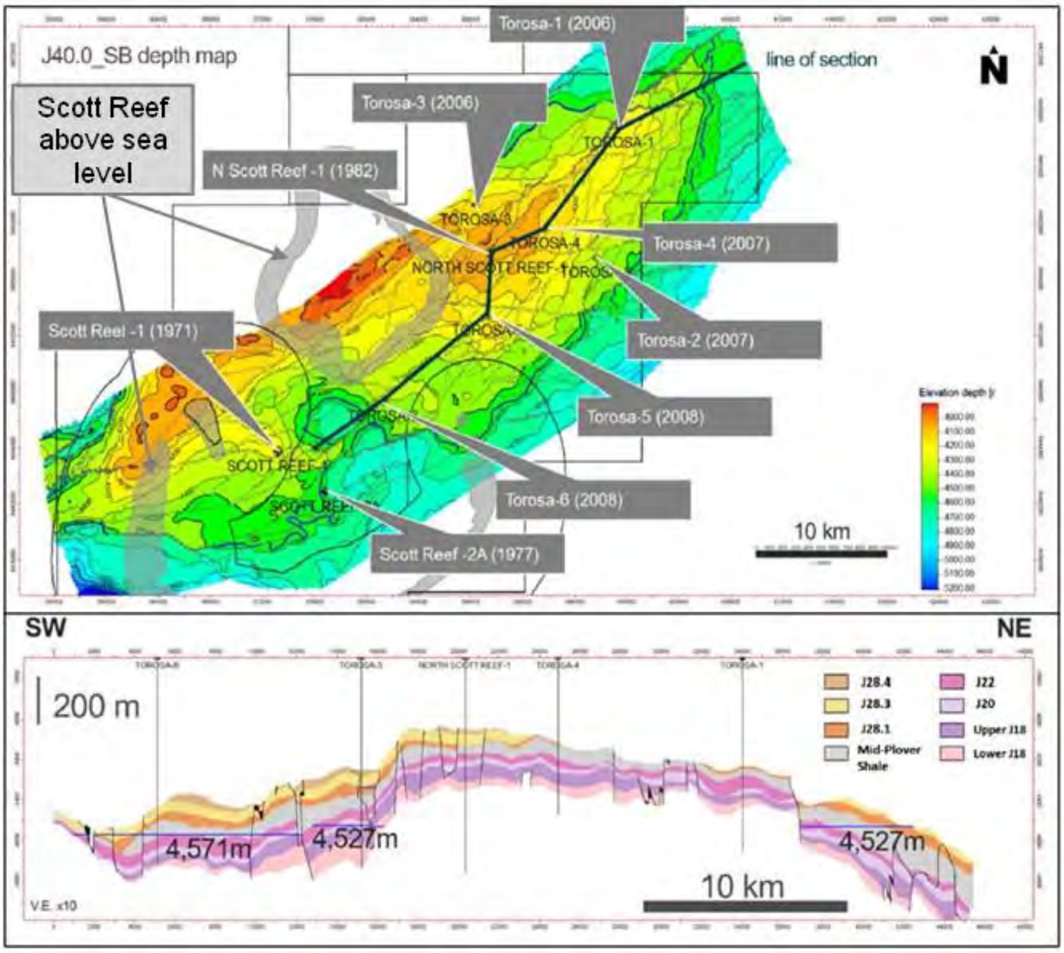
Source: Woodside

1.9.1 Field Description

Torosa

Torosa Field is 60 km long by 20 km wide with NE-SW oriented Jurassic-Triassic faults. It is fault-bounded to the west and dip closed to the north, south and east. The Jurassic J40.0 sequence boundary marks the top of the reservoir and the base of the regional seal in the area and is overlain by a thick sequence of shales and marls. Torosa is a complex structure on which nine exploration and appraisal wells have been drilled to date (Figure 27). Good quality 3D seismic data are available in the open water region, but there is a poorly imaged area under and adjacent to Scott Reef. This latter area also has a lower level of appraisal due to the limitations of the reef and associated physical environment imposing logistical issues.

Figure 27: Torosa Top J40 structure Map and Cross Section



Source: Woodside (GaffneyCline Modified)

Six drill stem tests were performed on three Torosa appraisal wells, Scott Reef-1, North Scott Reef-1 and Torosa-4, with rates varying from 10 to 46 MMscfd. The reservoir fluid is a lean gas condensate (CGR ~23 stb/MMscf) with moderate non-hydrocarbon content (8 to 12 mol% CO_2).

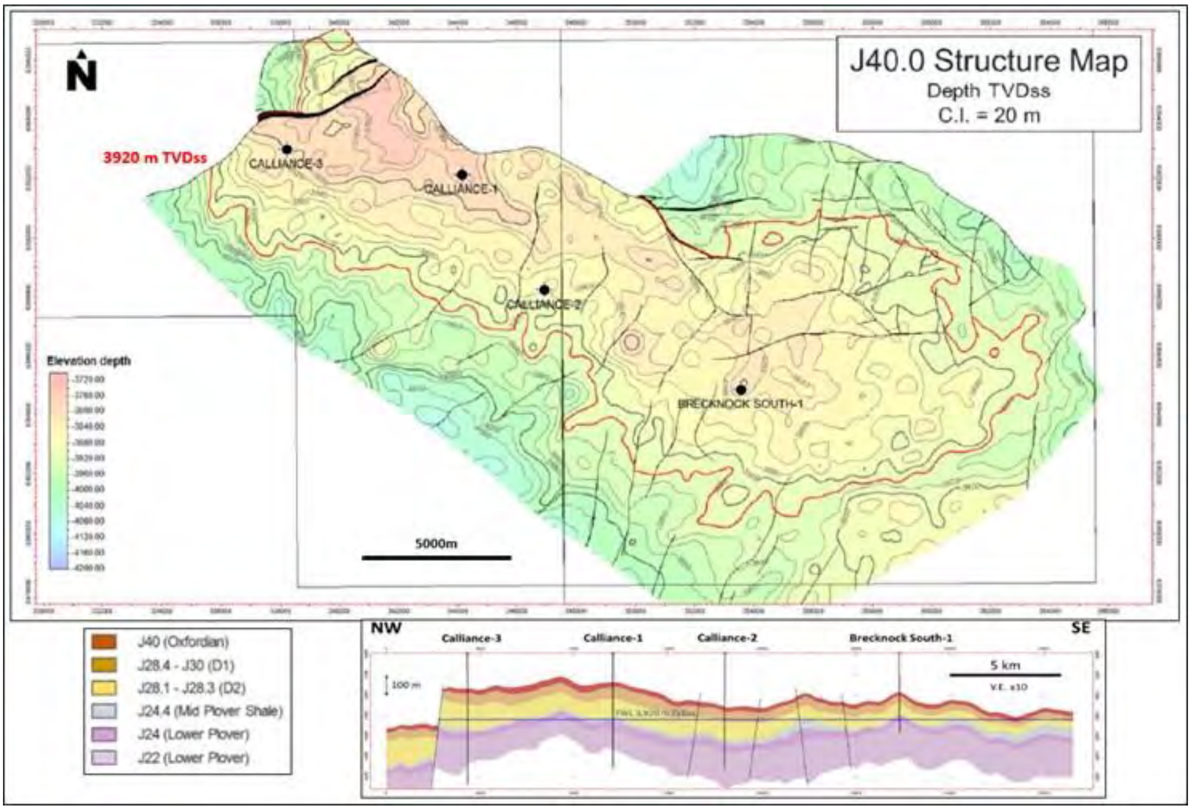
Woodside estimates that the proposed drainage plan will achieve good recoveries of 54% in the open water area. Volumes beneath Scott Reef are currently not part of the foundation project. The main uncertainties in Torosa are the Plover J28.3 reservoir distribution, J18 rock quality, fluid contacts across the field and potential compartmentalisation. An additional appraisal well is planned targeting volumes under North Scott Reef after field start-up.

GaffneyCline reviewed the static models provided by Woodside and considers the volume estimates as reasonable. The seismic interpretation was not reviewed but the documentation provided raised no concerns. Stratigraphic thicknesses of the reservoir intervals are an uncertainty in this syn-rift environment. The free water levels in the various fault blocks are also an uncertainty complicated by the distinct over-pressured aquifer. The overall recovery factor range of 33% to 39% is considered reasonable.

Calliance

Calliance is a broad low relief structure, 25 km long and 6 km wide as interpreted from the 3D seismic data and four exploration and appraisal wells (Figure 28). It consists of a NW-SE trending, tilted fault block at the Jurassic level. The field is bounded by major faults to the north and west, with a gentle dip closure to the south and east over older volcanic centres. The major NW-SE trending fault along its northern edge separates the field from the graben between Calliance and Brecknock. Calliance is covered by 3D seismic surveys which have been merged, reprocessed to pre-stack depth migration and includes a partial multi-azimuth (MAZ) depth migrated dataset.

Figure 28: Calliance Top J40 Structure Map and Cross Section



Source: Woodside (GaffneyCline Modified)

The Calliance field was discovered by Brecknock South-1 in 2000. It encountered a 130 m gas column in the upper Plover Formation. The discovery was appraised by Calliance-1 (2005), Calliance-2 (2007) and Calliance-3 (2008). These wells were drilled 8-20 km northwest of the discovery well and penetrated a similar reservoir section with a maximum gas column at Calliance-1 of 180 m across the Vulcan and Plover Formations. In addition to the full suite of wireline log data, the three appraisal wells were extensively cored (~700 m) and two flow tests in Calliance-1 achieved rates of 41 MMscfd and 20 MMscfd.

The primary reservoir is interpreted to be well connected due to thick, good quality, high net-to-gross sands and generally short faults of minor throw. Reservoir fluid comprises a fairly lean gas condensate (CGR ~35 stb/MMscf) with moderate non-hydrocarbon molar content (8–12% CO_2). Woodside estimates a recovery factor of 66%, which compares well with industry analogues given the challenging and remote operational environment. Table 28 shows estimates of GIIP, which GaffneyCline has reviewed and considers reasonable. The main subsurface uncertainties are the depth conversion in the low relief east of the field, the performance of the secondary J28.4-J30 reservoir unit and the aquifer strength. One appraisal well and an additional 3D seismic survey are planned.

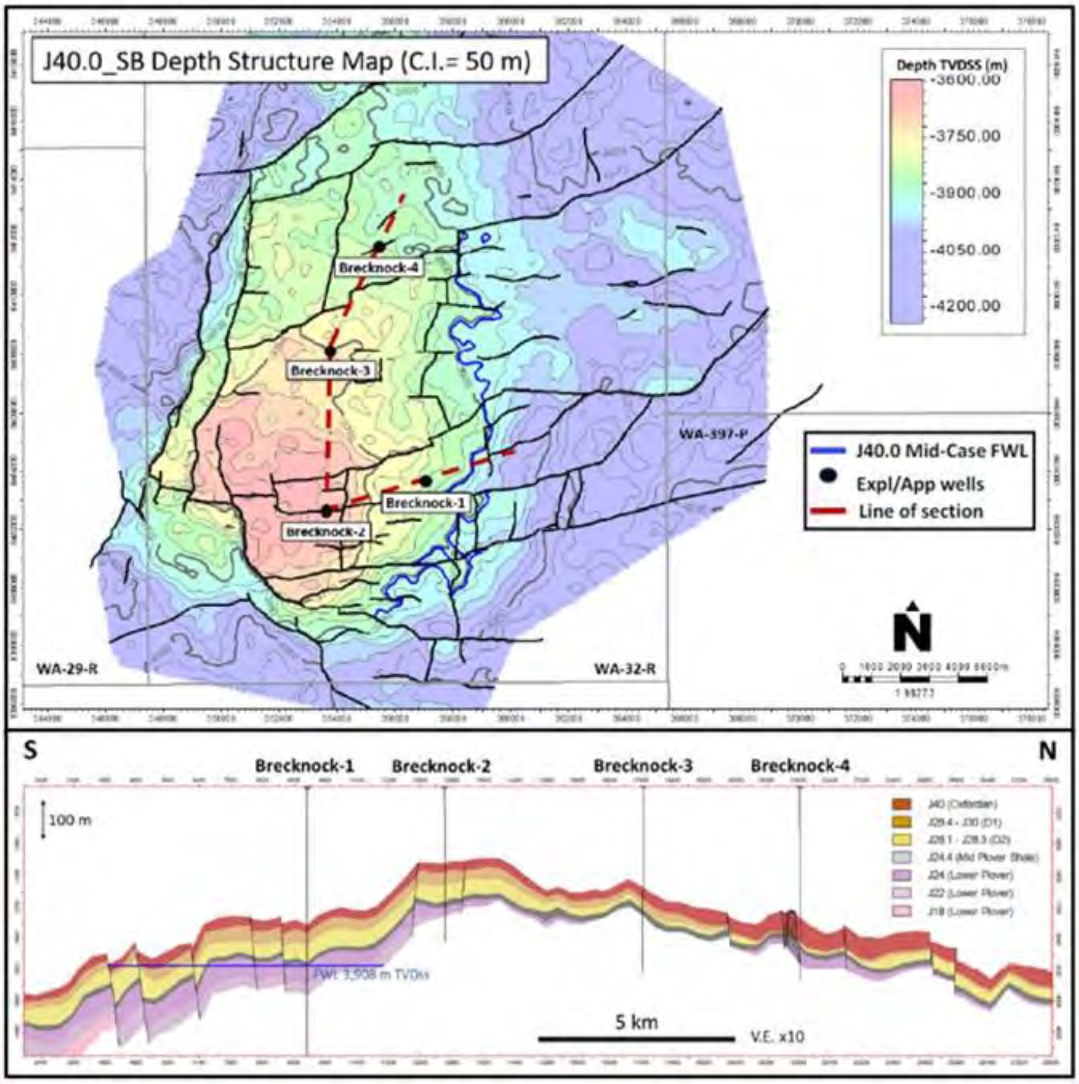
Brecknock

Brecknock is a dip and fault bounded anticlinal high relief structure consisting of the Plover Formation with moderate to good reservoir quality. The structure is 12 km by 8 km and is fault bounded on the west and south with dip closure at the Jurassic level to the east and north (Figure 29). The field is divided into regions by northeast to southwest trending faults. The Plover Formation reservoirs drape over a tilted Triassic basement fault block. Woodside report a change in seismic character from the flanks to the crest of the structure, which is interpreted to be due to the gradual thinning of the Plover reservoir section. The predominant reservoirs consist of fluvial, coastal, tidal and mouth-bar sediments that thin towards the crest and pinch-out to the north where the volcanics dominate. The two main reservoir units are the J22/J24 and J28.1-J28.3 with moderate to high net-to-gross, moderate to good porosities and permeabilities (100-1,000 mD). Two DSTs were performed in Brecknock-2 achieving rates of 44 MMscfd and 21 MMscfd.

The Brecknock development will depend on the production performance of the Calliance and Torosa fields. It is expected to be brought on stream in a second development phase to maintain plateau production rates at the Calliance/Brecknock FPSO. Four exploration and appraisal wells have been drilled on the structure. The reservoir fluid is a lean gas condensate (CGR ~25 Bbl/MMscf) with moderate non-hydrocarbon content (~8 mol% CO_2). Woodside's estimates of GIIP are indicated in Table 28.

GaffneyCline reviewed the static models provided by Woodside and considers the Contingent Resource estimates as reasonable based on the technical checks performed. No Seismic data were reviewed. The recovery factor range of 64% to 71% is considered reasonable for this geological environment.

Figure 29: Brecknock Top JB40 Structure Map and Cross Section



Source: Woodside (GaffneyCline Modified)

Woodside's estimates of gas and condensate initially-in-place are shown in Table 28.

Table 28: HCIIP Estimates, Torosa, Calliance and Brecknock Fields

Field	GIIP (Bscf)			CIIP (MMBbl)		
	Low	Best	High	Low	Best	High
Torosa	13,353	18,318	24,514	283	373	519
Calliance	9,691	12,342	15,912	354	450	532
Brecknock	2,388	3,825	4,600	54	92	120
Total	**25,432**	**34,485**	**45,026**	**690**	**915**	**1,170**

Notes:

1. Volumes are shown gross, including inert gas.
2. Totals may not be exactly equal to the sum of individual entries due to rounding

1.9.2 Field Development Plan and Production Profiles

The development concept envisaged for the Calliance, Torosa and Brecknock fields involves sub-sea wells tied back to two FPSOs, from where gas would be exported via pipeline to tie in to the existing Trunkline 2 (TL2) downstream of the North Rankin Complex, where it would join the supply of gas from the North West Shelf (NWS) fields to the onshore Karratha Gas Plant (see section 1.1). TL2 will be dedicated to Browse production.

The development is envisaged to be phased. In phase 1, 12 high rate, subsea wells would be drilled on Calliance and Torosa to supply the two FPSOs. Subsequent phases (2 to 4) will add up to 20 additional subsea wells in the base case. This would include 4 wells on the Brecknock field, which would be tied back to the Calliance FPSO when needed to maintain the plateau production rate. Technical data gathered as part of the initial development will help planning for subsequent phases.

The production profile presented by Woodside has first gas in 2030 and reaches the plateau rate of ~2 Bscfd by 2033, as shown in Figure 30. Wellhead gas is expected to have an average 10.5% of CO_2. Expected maximum condensate rates are 55 Mbcpd.

GaffneyCline reviewed the information included in the field development plan and conducted audit checks on fluid properties, recovery factors and deliverability. Woodside's production profile is considered reasonable.

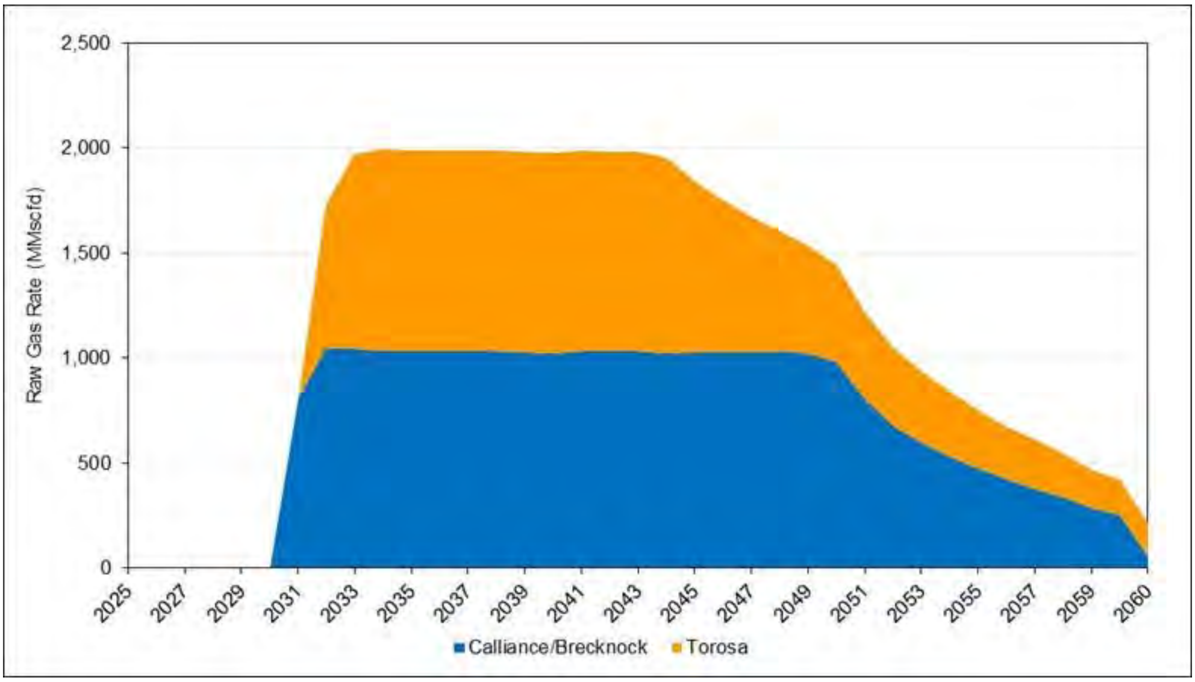
Table 29: Estimates of Recoverable Gas and Condensate from Browse Fields.

Field	Gross Best Estimate Recoverable Volumes	
	Dry Gas (Bscf)	Condensate (MMBbl)
Torosa	7,070	131
Calliance	6,790	211
Brecknock	2,460	49
Total	**16,320**	**390**

Notes:

1. Offshore Consumed in Operations (CiO) volumes of 689 Bscf are included in the above volumes.
2. Non-hydrocarbon components (mainly CO_2) of 1,717 Bscf are included in the above volumes.

Figure 30: Woodside's Combined "Browse to NWS" Production Profile



Source: Woodside

1.9.3 Facilities and Cost Estimates

The Browse development has gone through a number of concept development phases. Despite the large volumes of gas present, the remote location has made development challenging. Initial concepts to develop the fields with a greenfield LNG plant at James Price Point (2010), and with Floating LNG (FLNG) vessels (2015) failed to meet economic hurdles. During these earlier studies, development via the NWS liquefaction facilities at the Karratha Gas Plant (KGP) was considered but discarded due to the lack of available capacity at KGP.

It is now clear that there will be sufficient liquefaction ullage available at KGP from 2030 onwards to process the full Browse production (see NWS section 1.1.4). The current "Browse to North West Shelf (NWS) Project" concept has therefore been selected following a review of 39 development options conducted from 2016 onwards. Use of the existing NWS facilities reduces overall project CAPEX compared to a full greenfield development and is economically more attractive.

The Browse development overview is shown in Figure 31. Each of the two FPSO's will provide gas/liquids separation, gas processing and dehydration, condensate treatment and stabilization, and gas export compression. Gas exported to shore is expected to have 2.5% of CO_2, which will be further reduced at the LNG plant. In later years, depletion compression can be installed to improve recovery. The offshore facilities will be operated remotely via fibre optic cable link to an operations centre in Perth.

Figure 31: Browse Development Overview

The Torosa FPSO will supply gas to an 83 km x 34" pipeline, which will tie in to an 833 km x 42" pipeline from the Calliance FPSO to a tie in to one of the two existing NWS trunk-lines to KGP. In this way, full use is made of the existing NWS/KGP infrastructure and relatively minor modifications will be required to the KGP itself, apart from facilities life extension provisions.

The Browse development plan indicates a development period of circa 5 years from FID to first gas from the first (Calliance) FPSO. First gas on the second (Torosa) FPSO will follow 12 months later, allowing sequencing of the two vessels during construction.

The Browse to NWS Project is predominantly based on proven technologies with the development's two FPSOs and subsea and pipeline facilities within the range of industry experience, which should keep project execution risks manageable. The function of the FPSOs includes receipt of gas from the subsea system, acid gas removal and venting, gas hydrocarbon and water dew pointing, gas export compression, condensate stabilisation, storage and offloading, and produced water treatment for disposal. Woodside has included provisions in the design for potential future depletion compression, carbon capture and storage and produced water injection provided they are economically justifiable.

Browse end of field life is not expected to occur before 2050, so D&R planning is at a conceptual level.

GaffneyCline has reviewed comprehensive cost forecasts provided by Woodside covering capital costs (CAPEX), operating costs (OPEX), and D&R costs for the offshore Browse and onshore KGP operations from 2021 to the end of field life and completion of D&R activities. GaffneyCline has accepted Woodside's detailed CAPEX and OPEX cost forecasts as reasonable. GaffneyCline has amended the D&R estimate in line with current industry practice, i.e. removal of subsea flowlines and equipment, removal of the FPU's, and P&A of all wells. The export pipeline is assumed to be cleaned and left in situ.

Gross life of field CAPEX for the Browse development is estimated to be US$20,813 MM of which US$14,337 MM is estimated to first production.

1.9.4 Contingent Resources

Estimates of Contingent Resources are shown in Table 30. The Browse development project is classified On Hold due to limited field project activity since 2010 and uncertainty on whether it will go ahead.

Table 30: Gross 2C Contingent Resources for Browse, as at 31st December 2021

Field	Gross 2C Contingent Resources	
	Dry Gas (Bscf)	Condensate (MMBbl)
Torosa, Calliance and Brecknock	14,603	390

Notes:

1. Offshore Consumed in Operations (CiO) volumes of 689 Bscf are included in the above volumes.
2. Non-hydrocarbon components (mainly CO_2) of 1,717 Bscf are excluded from the above volumes.

1.10 Greater Sunrise

The Sunrise and Troubadour fields, collectively known as the Greater Sunrise fields, are currently located in Retention Leases NT/RL2 and NT/RL4 in Australian waters, and in PSC 03-19 and PSC 03-20 in Timor-Leste waters (formerly in the Joint Petroleum Development Area). Woodside is the operator with 33.44% interest. Pursuant to the treaty between Australia and Timor-Leste establishing their maritime boundaries in the Timor Sea brought into force on 30th August 2019, the Governments of Australia and Timor-Leste and the Sunrise Joint Venture are required to enter a new production sharing contract which will replace the four current titles. Negotiations are ongoing. The Sunrise Joint Venture (SJV) participants are Woodside (Operator), Timor Gap and Osaka Gas.

Woodside has informed GaffneyCline that the same treaty establishes the "Greater Sunrise Special Regime" and that Annex B, Article 2 thereof includes the following text:

1. *Timor-Leste and Australia shall have title to all Petroleum produced in the Greater Sunrise Fields.*

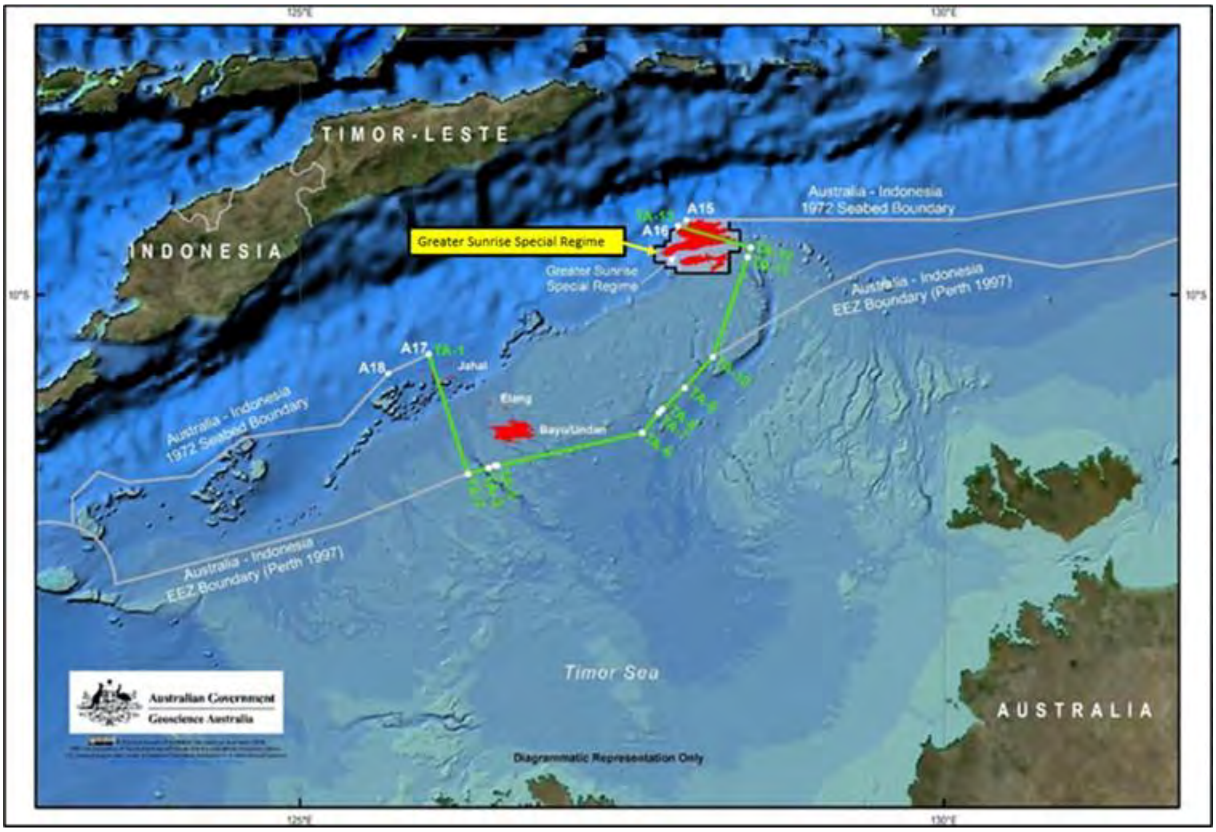
2. *The Parties shall share upstream revenue, meaning revenue derived directly from the upstream exploitation of Petroleum produced in the Greater Sunrise Fields:*

   a. *in the ratio of 70 per cent to Timor-Leste and 30 per cent to Australia in the event that the Greater Sunrise Fields are developed by means of a Pipeline to Timor-Leste; or*

   b. *in the ratio of 80 per cent to Timor-Leste and 20 per cent to Australia in the event that the Greater Sunrise Fields are developed by means of a Pipeline to Australia."*

These fields lie approximately 150 km southeast of Timor-Leste and 450 km north of Australia in an area where the water depth varies between 100 and 600 m. North of the Sunrise Field the water depth increases to approximately 3,000 m in the Timor Trough (Figure 32).

Figure 32: Greater Sunrise Fields Location Map



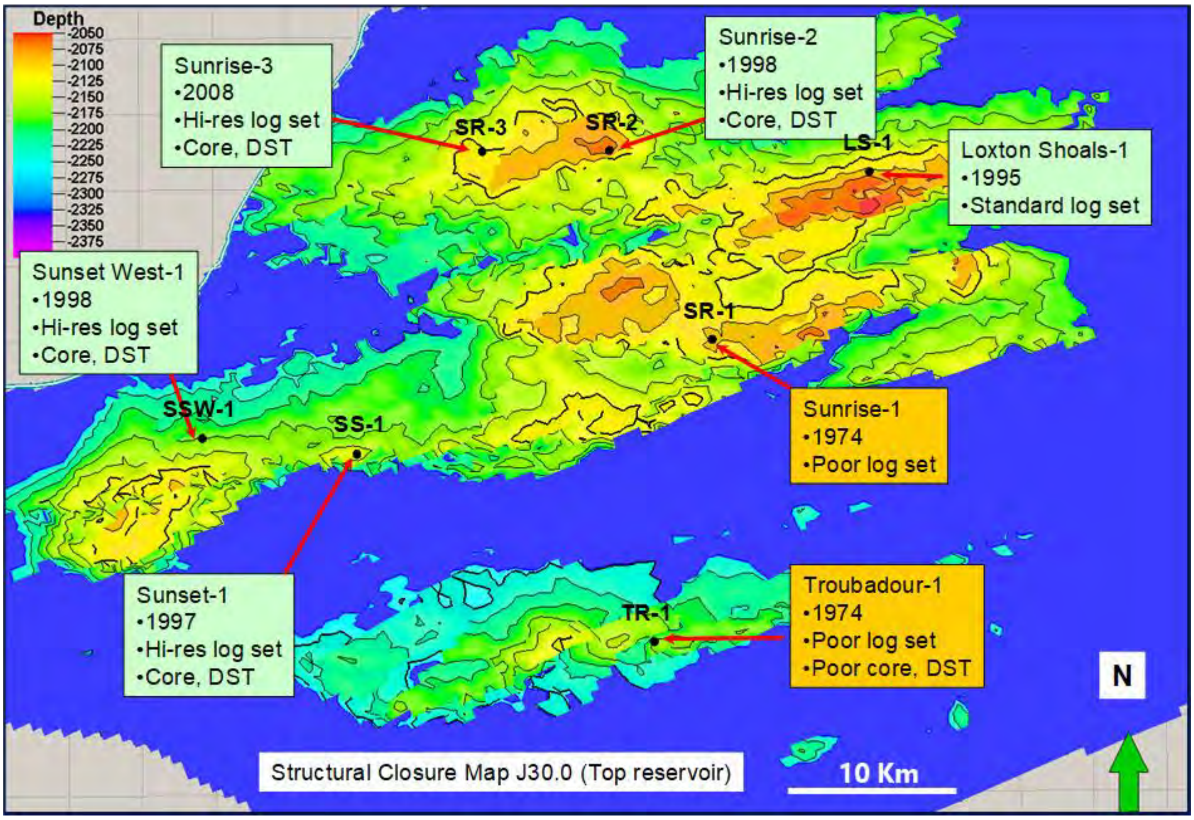
Source: Australian Gov. Dept. of Foreign Affairs & Trade.

1.10.1 Field Description

The Greater Sunrise fields are located within the Bonaparte Basin on the Sunrise High, a major regional feature on the east of the Sahul Platform. The Greater Sunrise fields were discovered by the Troubadour-1 and Sunrise-1 wells in 1974. Since then six appraisal wells have been drilled and, in 2000, the Mescal 3D seismic survey was acquired. Technical studies have confirmed the presence of a significant gas resource.

The 3D seismic data and well penetrations allow for the interpretation of the fault complex, which consists of large elongated east west trending fault blocks (75 x 50 km overall) with ~165 m of structural relief. A large fault (1 km throw) forms the northwest boundary of the closure and a central easterly trending fault (150 m throw) separates the Sunrise Field from the Troubadour Field to the south. Smaller north-easterly and easterly faults with throws of less than 80 m are common. The Greater Sunrise map is presented in Figure 33.

Figure 33: Greater Sunrise Structure above Free Water Level

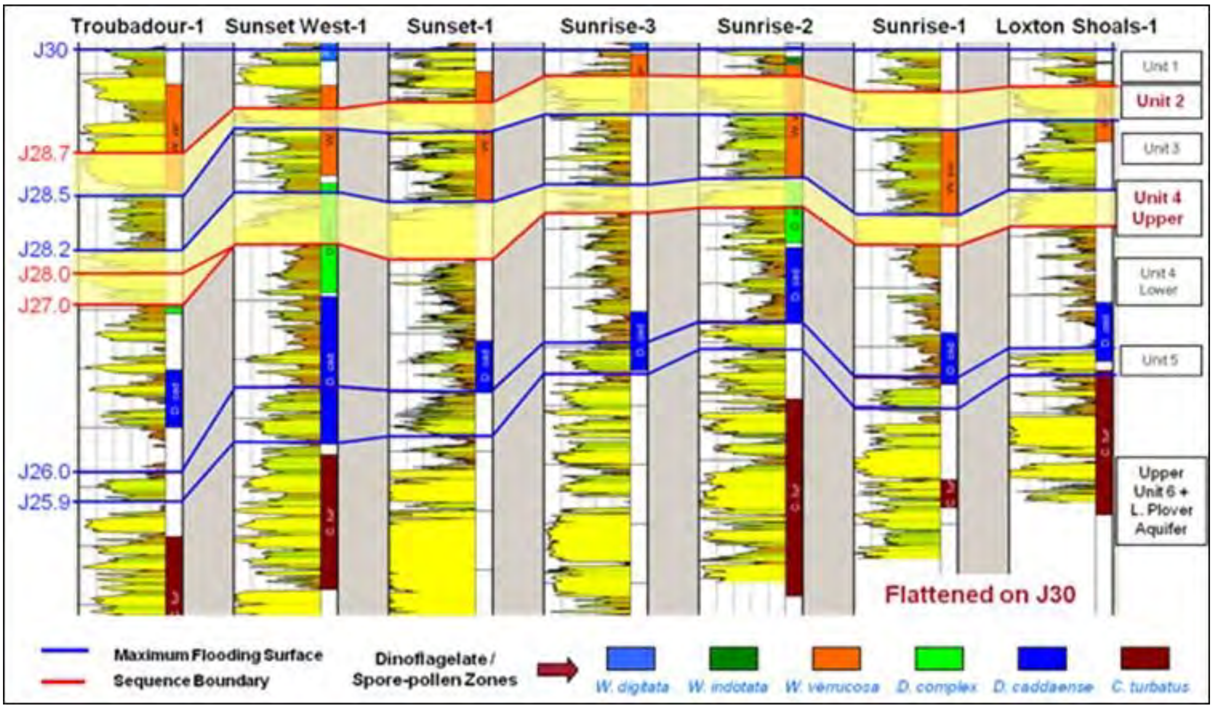


Source: Woodside

The gas bearing reservoir interval at Sunrise and Troubadour is 60 to 80 m thick and composed of inter-bedded marginal marine to marine quartzose sandstones, siltstones and shales of the Middle Jurassic Plover Formation. Within this section, the majority (approximately 80%) of the gas occurs within two laterally extensive, middle to upper shoreface sandstone intervals (Unit 2 and 4) with average thicknesses of approximately 10 m. These two intervals are separated by a ~30 m thick sequence of marginal marine to marine heterolithic deposits (Figure 34).

Transgressive marine siltstones and claystones of the Flamingo Group (Callovian to early Oxfordian age) overlie the Plover Formation, forming the top seal. Woodside interprets that the edge aquifers to the east, south and west are expected to provide reasonable pressure support and water influx.

Figure 34: Greater Sunrise Wells Cross Section



Source: Woodside

3D seismic data acquired in 2000 and reprocessed in 2007 and 2008 are of reasonable quality and the wireline well data are extensive, with the Sunrise-3 well proving to be an excellent source of reservoir and test data. The main subsurface uncertainties are GIIP (with structure and facies predominating), reservoir behaviour, particularly that of intra field faults and their transmissibility, and aquifer support. Subsurface uncertainty, particularly dynamic performance, is a major risk and the development will be phased so that technical data acquired in early phases can be used to optimise future phases.

1.10.2 Field Development Plan and Production Profiles

The Sunrise Joint Venture Participants have completed a technical and commercial evaluation of various development concepts including a Floating Liquefied Natural Gas (FLNG) facility located over the Sunrise Field. However, at this stage there is no preferred concept. In the FLNG concept studied, the annual average sales capacity was approximately 4.1 Mt p.a. and the facility would separate condensate for export. The development wells and associated subsea infrastructure would be installed across five development phases, including compression, resulting in approximately 26 wells in total. The first development phase would consist of approximately seven production wells and associated subsea facilities.

Learnings from initial phase static and dynamic reservoir performance data would be used to further optimise future development phases including development of the Troubadour Field.

Based on the FLNG development case studied, gas recovery incorporating compression is projected to be 54%. This equates to a Sunrise Joint Venture agreed dry gas, 2C Contingent Resource estimate of 5.13 Tscf. The Sunrise Joint Venture agreed condensate CR estimate is 226 MMBbl.

The currently reported Resources estimates are based upon the results of studies completed in 2009. Woodside classifies the Sunrise/Troubadour project as Contingent Resources Development Not Viable. Under PRMS, the project might also be classified On Hold, due to the uncertainty of regulatory conditions, fiscal terms and development concept. GaffneyCline adopted Woodside's estimates of gross Contingent Resources (Table 31).

Table 31: GIIP and Gross Contingent Resources for Greater Sunrise as at 31st December 2021

Field	GIIP (Bscf)	Gross 2C Contingent Resources	
		Gas (Bscf)	Condensate (MMBbl)
Greater Sunrise	10,736	5,134	226

1.11 Other Australia Assets

In addition to discovered and producing assets described in preceding sections, Woodside also has outstanding D&R obligations in respect of two fields, Balnaves (produced 8 MMBbl) and Stybarrow (produced 57 MMBbl) that have ceased production, where decommissioning and restoration activities are in planning or in progress.

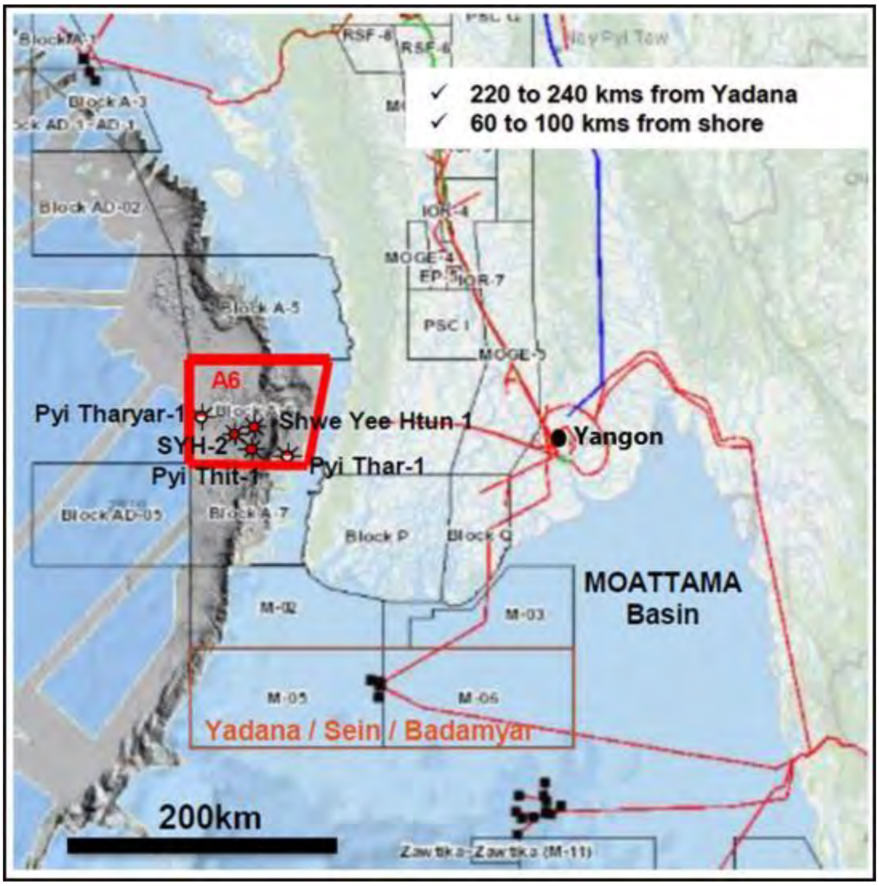
2 Woodside Myanmar

At the effective date of this CPR, Woodside had an interest in offshore Block A6 in Myanmar. However, Woodside issued an ASX announcement in January 2022 that it had decided to withdraw from its interests in Myanmar. Nonetheless, given this CPR's effective date, the asset is included in the CPR and is briefly described below.

Woodside's Myanmar Block A6 is operated by TotalEnergies (Figure 35) and covers an offshore area of 8,928 km^2 in the Rakhine Basin of Western Myanmar. The A6 Block is situated in a water depth ranging from 30 to 2,500 meters and is located 260 km west of Yangon and 250 km northwest of the Yadana/Sein/Bandamyar offshore gas fields also operated by Total. The joint venture comprises Woodside (40%), MPRL (Government Liaison operator, 20%) and TotalEnergies (40%). However, after government back-in to any development, Woodside's interest would be reduced to 25%.

The Block A-6 PSC expires on the 23 December 2022. JV partners have been under negotiation with MOGE (Myanmar national oil company) for PSC retention. However, the future of any development in Block A-6 is uncertain due to the political situation in Myanmar. Note that on 27th January 2022 (after the effective date of this CPR), Woodside announced it was withdrawing from its interests in Myanmar.

Figure 35: Block A6 Myanmar Location Map



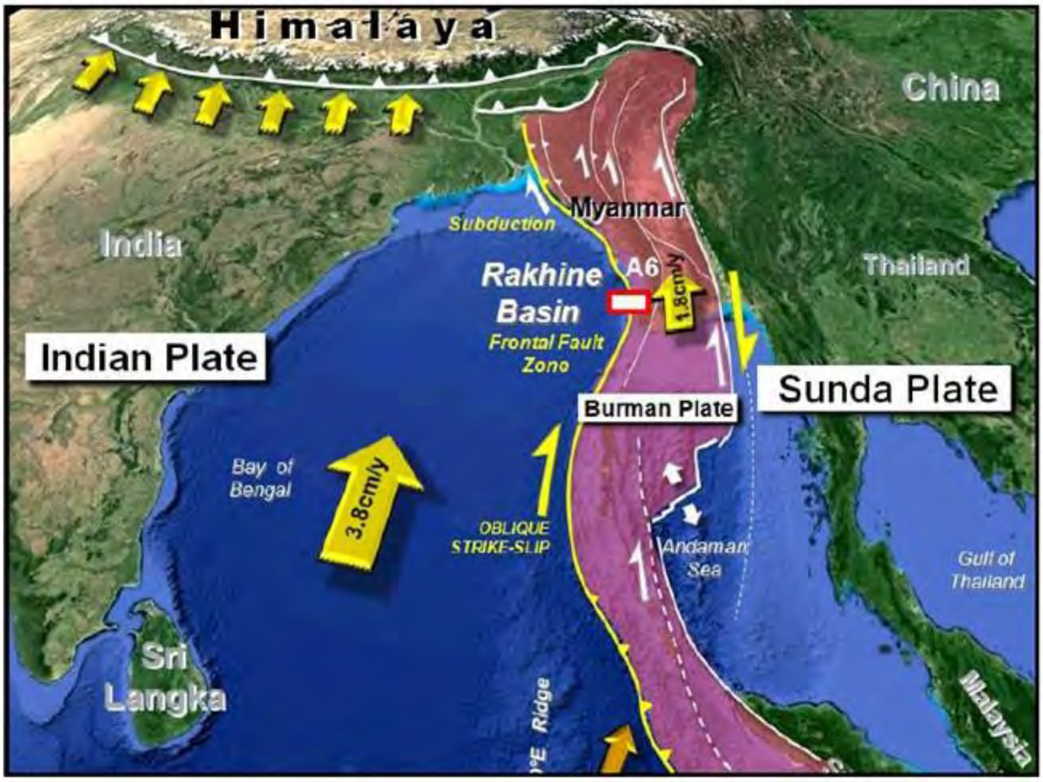
Source: Woodside (GaffneyCline Modified)

2.1.1 Field Description

The Rakhine Basin lies offshore Myanmar at the junction between the Indian and Sunda tectonic plates that are separated by a strike-slip frontal fault zone (Figure 36).

The basin receives sediment influx in the northern part from the Bramaputra/Ganges system, whereas sediments from the paleo-Irrawaddy system fill the eastern part of the basin, where the A6 Block is located. The front thrust compression induced the Saung anticline structure, where several confined turbiditic channels are identified, which form the basis of the LCC-3C and LCC-1A discoveries.

Figure 36: Block A6 Structural Setting



Source: Woodside

The Shwe Yee Htun (LCC-3C) gas accumulation was discovered by the Shwe Yee Htun-1 well, which was drilled between November 2015 and January 2016. Shwe Yee Htun-1 encountered 127.5 m of gross gas column, with 32 m of net sand in turbidite Pliocene Formation sandstone units. The Shwe Yee Htun gas accumulation was appraised by the Shwe Yee Htun-2 well between July and September 2018. Shwe Yee Htun-2 encountered 168 m of gross gas column with 41 m of net sand in the same formation. The Pyi Thit (LCC-1A) gas accumulation was discovered by the Pyi Thit-1 well in July 2017. Pyi Thit-1 encountered 65 m of gross gas column, with 32 m of net sand in Pleistocene Formation sandstone units.

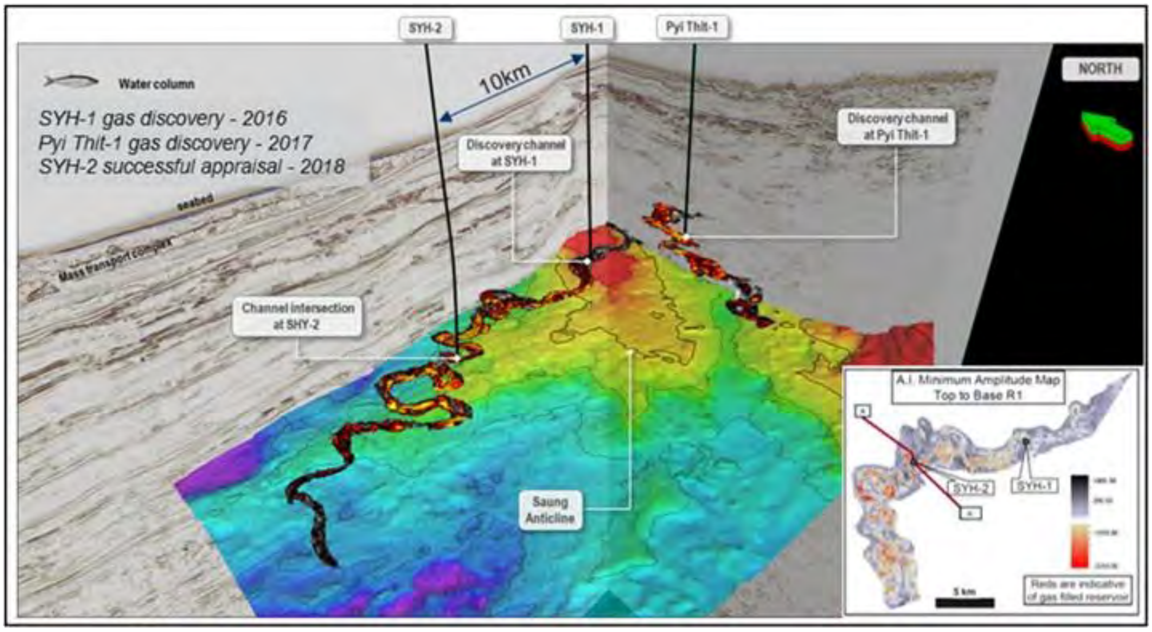
Gas compositional analysis of the numerous samples acquired indicates, on average, almost pure methane of biogenic origin (99.5% C1).

LCC-3C

Four LCC-3C gas bearing reservoirs were penetrated (R1, R2U, R2L and R3) by the two exploration/appraisal wells with biogenic dry gas and net sand thicknesses encountered of 10 to 20 m per reservoir. A porosity range of 18 to 23 % was measured with permeability at 50 to 65 mD estimated by the SYH-2 drill stem test (DST). The DST was performed across a 35 m section of the reservoir and flowed at ~53 MMscfd on a 40/64” choke over 80 hours.

The Free Water level encountered is consistent with the DHI (Direct Hydrocarbon Indicator) observed on the seismic (Figure 37). GaffneyCline reviewed the static model provided by Woodside and considers the volume estimates as reasonable based on the technical checks performed. The volumes were reproduced in the Petrel model provided with estimates also confirmed utilising a probabilistic (Monte Carlo) analysis with GaffneyCline's vetted reservoir parameters. The mapped turbidite channels utilising the seismic amplitudes defined the lateral reservoir extents. This is one of the major uncertainties along with vertical connectivity, net to gross distribution and subsequent production contribution from thin and poorer facies in this slope turbidite environment. The recovery factor range of 64%-73% is considered reasonable for this geological environment.

Figure 37: Shwe Yee Htun (LCC-3C) and Pyi Thit (LCC-1A)



Source: Woodside

LCC-1A

Three LCC-1A gas bearing reservoirs were penetrated (R1, R2 and R3) by the Pyi Thit 1 (PYT-1) exploration well which was plugged and abandoned on the 20th August 2017. Biogenic dry gas at ~99.5% C1 was encountered with net sand thicknesses of 20 to 30 m per reservoir. The porosity range was measured from 20 to 25% with a permeability at 150 mD as estimated by the PYT-1 DST. The DST was performed across a 29 m section of the reservoir and flowed at ~50 MMscfd on a 44/64" choke over 44 hours with strong reservoir pressure support. GaffneyCline reviewed the static model provided by Woodside and considers the volume estimates as reasonable based on the technical checks performed. A similar workflow to the LCC-3C review was also performed with similar uncertainties also applicable as discussed above. The recovery factor range of 64 to 70% is considered reasonable for this geological environment.

Table 32 shows the GIIP and the Gross Contingent Resource proposed by Woodside, which GaffneyCline has reviewed and considers within audit tolerance.

Table 32: Myanmar GIIP and Gross Contingent Resources, as at 31st December 2021

Reservoir	GIIP (Bscf)	Gross 2C Gas Contingent Resources (Bscf)
LCC-3C	2,590	1,787
LCC-1A	740	480
Total	**3,330**	**2,267**

Notes:

1. The offshore Consumed in Operations (CiO) volumes are 33 Bscf for the LCC-3C and the LCC-1A joint development proposed by the Operator.
2. Gross Contingent Resources are 100% of the volumes estimated to be recoverable from the LCC-3C and LCC-1A discoveries in the event that they are developed.
3. The volumes reported here are “unrisked” in the sense that no adjustment has been made for the risk that LCC-3C and LCC-1A may not be developed in the form envisaged or may not be developed at all (i.e. no “Chance of Development” factor has been applied).

2.1.2 Field Development Plan

The currently defined development plan consists of a subsea tie back to a new dehydration and compression platform located 65 km away on the shelf, and an export pipeline tied in downstream of Yadana (to a new riser platform). The number, phasing and location of the wells is still being optimized, but due to the current political instability in Myanmar, Woodside and the JV partners have all decisions under review.

The development concept envisages ten near-vertical gas producing wells with open hole gravel pack (OHGP) completions (six wells at start-up, two infill wells and two contingency wells drilled at a later stage to maintain the plateau).

A plateau rate of 400 MMscfd is envisaged with a shallow water hub on the shelf of the block where a conventional integrated processing platform would enable pressure break and gas treatment for further export. The platform would be installed by float-over with an export flowline of 265 km connected with a riser platform to both MGTC (Thailand export pipeline) and the Yangon domestic pipeline.

Woodside has indicated that the project is currently “sub-commercial and technically immature”, so GaffneyCline considers the project maturity sub-class as Development Not Viable.

3 Woodside Senegal

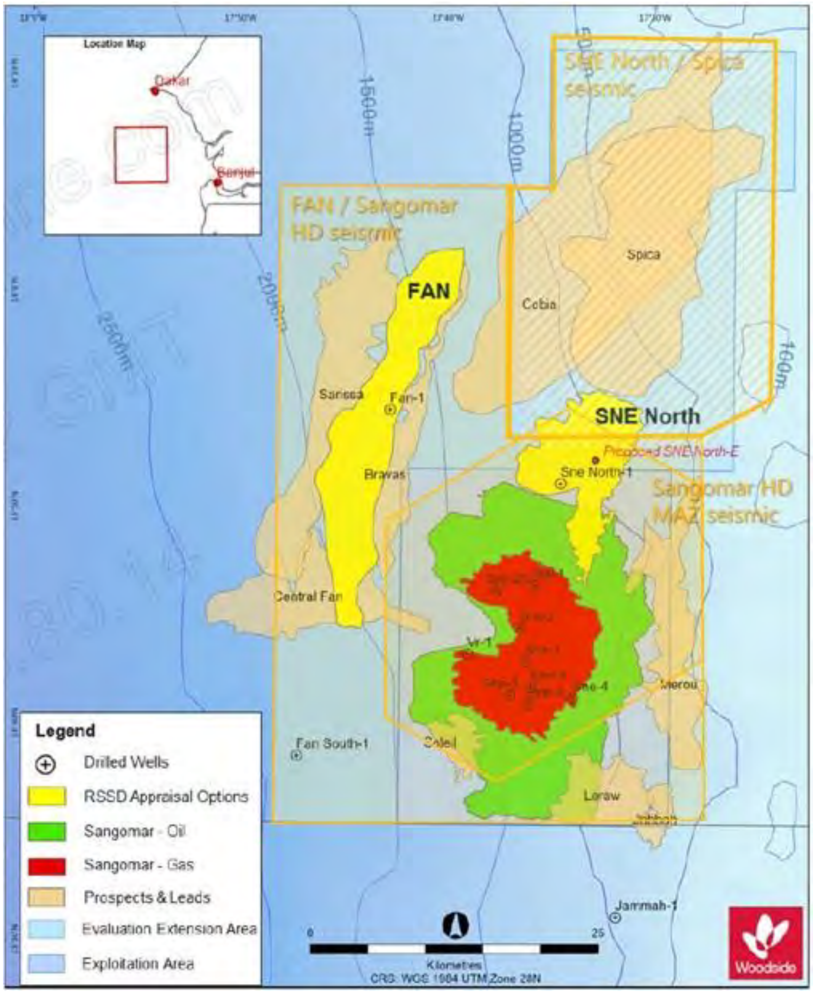
Woodside is operator of the Rufisque Offshore, Sangomar Offshore and Sangomar Deep Offshore (RSSD) Production Sharing Contract (PSC), which contains the Sangomar Exploitation Area, and is also operator of an Evaluation Extension Area (EEA), in which two discoveries, FAN and SNE North are located. Woodside has 82% participating interest in the Sangomar Exploitation Area and 90% in the EAA, the remaining 18% and 10% being held by

PetroSen (the Senegalese National Oil Company). The Sangomar field was previously known as SNE.

The EEA was due to expire in October 2021 and the RSSD JV submitted a PSC extension application to the Ministry of Energies in August 2021 for a period of three years. The RSSD JV remains on title whilst discussions on the terms of the extension are ongoing.

The RSSD licence is located offshore Senegal, approximately 100 km southwest of Dakar, in water depth ranging from less than 200 m to more than 2,000 m (Figure 38).

Figure 38: Location Map of the RSSD Licence and Discoveries



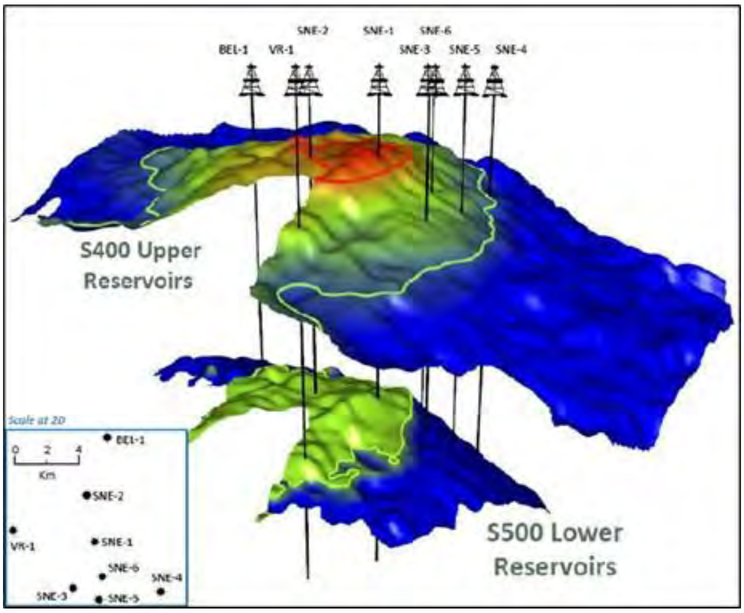
Source: Woodside

3.1 Sangomar Field

3.1.1 Field Description

Sangomar was discovered in 2014 by exploration well SNE-1 and has been appraised by seven further wells, SNE 2-6, BEL-1 and VR-1 (Figure 39). The exploration and appraisal wells found hydrocarbons at several horizons and confirmed two key reservoir zones: the S400 zone (S440, S460, S470, S480 and S490 reservoirs) and the deeper S500 zone (S520 and S540 reservoirs). The appraisal campaign has provided a good dataset comprising well data, geophysical logs, core, pressures and drill stem tests. Recent acquisition of a multi-azimuth seismic dataset has resulted in the re-interpretation of the field. These data provide the basis for the ongoing field development and can act as a baseline survey for any future 4D seismic acquisition. The multi-azimuth 3D seismic resulted in a change to the drilling sequence and reservoirs targeted in the first development well, drilled late in 2021, the results of which are interpreted to be positive.

Figure 39: Sangomar Reservoir Units and Appraisal Wells



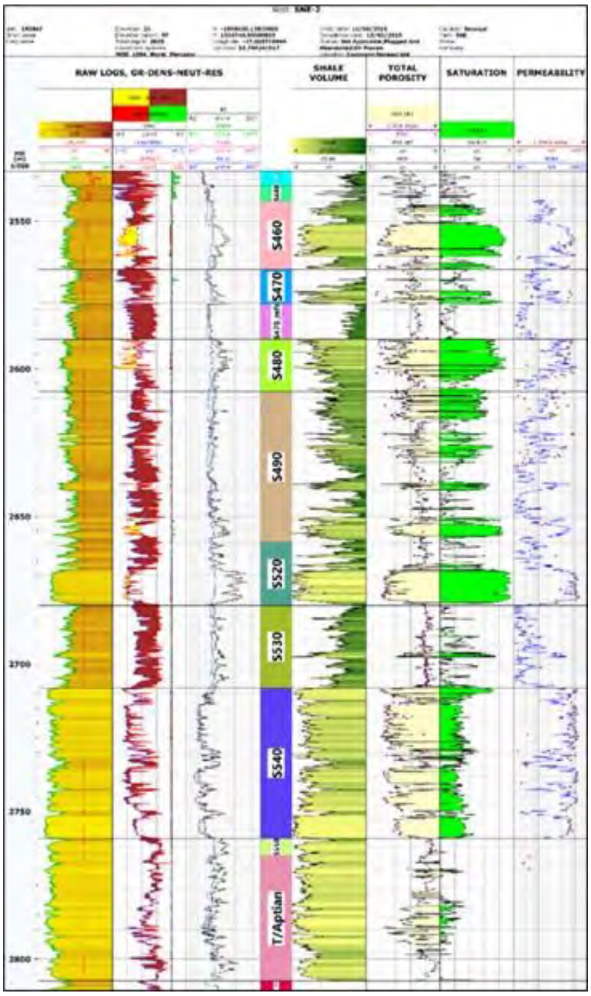
Source: Woodside

The multi-azimuth seismic data provides a significant uplift in data quality compared to the legacy 3D seismic (reprocessed several times). These new data provide better illumination of the reservoir and particularly provide a better image of the S400 reservoir interval.

The S500 sandstone reservoirs are interpreted to be lobe and channel deposits of submarine turbidites in a pro-delta setting, which infilled karstified topography at the top of the underlying carbonate platform. The S520 and S540 reservoirs, to be developed in Phase 1, comprise fine-grained, moderately to well sorted sandstones and present as stacked sands with blocky log profiles (Figure 40).

The lower S400 reservoir (S440 to S490) are finer grained sandstones, and are more variable than the S500 reservoirs, consisting of silty to very fine grained, moderate to well sorted sands with silty claystones and heterolithics, with high levels of bioturbation throughout. The S460 and S480 reservoirs are to be developed in Phase 1, and are considered to have been deposited by low-density turbidite flows within a pro-delta setting. Core and seismic data have been analysed and deposition is interpreted to have occurred as a complex of sediment wave features with a proportion of the deposition occurring within small channel features and levee settings. The multi-azimuth 3D seismic has provided additional higher resolution data and the interpretation of the sand-wave geometry is being refined and the results incorporated into the well planning.

Figure 40: Sangomar Type Well (SNE-2)



Source: Woodside

Average reservoir properties for the primary Sangomar reservoirs as reported in the Exploitation Plan are shown in Table 33.

Table 33: Sangomar Average Reservoir Properties

Item	SNE 460	SNE 480	SNE 520	SNE 540
Average gross thickness (m)	21	22	20	51
Average net to gross (%)	64	70	42	58
Net porosity (%)	22	22	24	24
Net permeability (mD)	57	91	456	453
Average pay water saturation (%)	32	31	13	23

In addition to the principal S400 and S500 reservoirs, a number of minor reservoirs have been found to be hydrocarbon bearing. The shallowest reservoirs are the gas bearing S410/S420, comprising mudstones and siltstones, heterolithics and thin bedded sandstones. The S410 has a higher net to gross ratio than the underlying S420. Pressure data indicate that the S410 and S420 are separate reservoirs and also that they lie on a separate pressure regime to the underlying oil field. The gas has a lower CO_2 content (<2%) than the main field.

The S440 reservoir is the shallowest oil-bearing reservoir and is relatively thin, comprising mudstone lithologies with thin sandstones, interpreted to have been deposited by distal low-density turbidity flow. The sediment may be infilling the lows between the sand waves in the underlying S460 reservoir.

The S470 oil bearing reservoir lies between the S460 and S480 reservoirs and is mudstone dominated, but includes 1 to 4 m thick sharp based sandstones. These are interpreted to have been deposited as part of a developing lobe complex.

None of these reservoirs are planned to be developed during Phase 1. Data and information gathered during Phase 1 will be required to assess their commercial potential.

From 2015 to 2017 DSTs were performed in SNE-2 (S520 and S490), SNE-3 (S490 and S480) SNE-5 (S480, S470 and S460) and SNE-6 (S480). The S540 reservoir has not been flow tested.

More than 80% of the estimated recoverable volumes attributed to the first phase of development are expected to be recovered from the S520 reservoir, in which a single DST in well SNE-2 was performed. Analysis of this test showed no barriers to flow at least to an estimated radius of 1.2 km, and high average effective oil permeability greater than 750 mD. In contrast every DST in the S460 and S480 has been interpreted with two or more boundaries, confirming the different flow characteristics (more tortuosity) of these reservoirs in comparison with the S520. Estimates of permeability for the S400 reservoirs vary between 30 mD and 210 mD.

An interference test involving SNE-5, SNE-6 and SNE-3 showed continuity over a distance of 1.5 km within the S480 reservoirs in the north-south direction but no continuity in the east-west direction over a distance of 2.0 km. This is consistent with the wavy nature of the sand deposition. Anisotropy of reservoir continuity results in uncertainty in the efficacy of the planned waterflood in the S400 reservoirs.

A comprehensive dataset of static pressures has been acquired in wells SNE-1 to 6, VR-1, BEL-1, as well as SNE North-1 and FAN-1. Best estimate fluid contacts from interpretation of pressure gradients are shown in Table 34. The GOCs in the S460 and S480 are for all practical purposes the same, as are the FWLs in the S520 and S540. Woodside has indicated that the second development well, drilled late in 2021 targeting the crest of S520, confirmed that no gas cap had been intersected there. This is interpreted to be a positive outcome.

Table 34: Sangomar Fluid Contacts from Pressure Measurements

Reservoir	FWL (mss)	GOC (mss)
S460	2,673	2,585
S480	2,673	2,587
S520	2,684	N/A
S540	2,682	N/A

Reservoir pressure and downhole fluid analysis indicate that BEL-1 is in a separate compartment to the core area of the field. However, this is expected to impact primarily the S400 reservoirs and it is not regarded material for the Phase 1 development.

Reservoir fluid properties from sampling are summarised in Table 35. The SNE reservoir fluid shows depth and lateral variation in properties such as saturation pressure, density, GOR and viscosity. These variations are more evident in the S400 reservoirs than the S500 reservoirs, although data coverage in the S500 reservoirs is lower.

Table 35: Sangomar Reservoir Fluid Properties

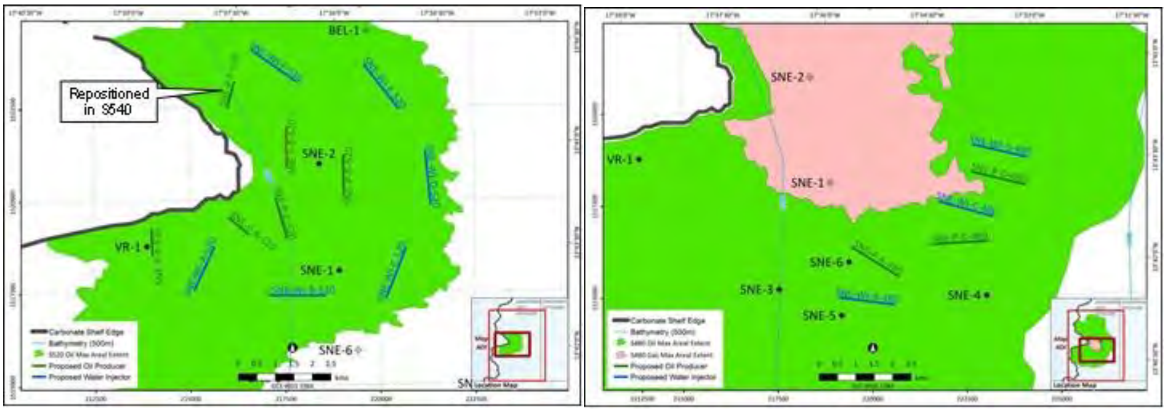
Item	S520	S520	S470	S480	S480
Well	SNE 2	SNE 1	SNE 3	SNE 4	SNE 1
Fluid type	oil	oil	oil	oil	gas
Sample depth (mss)	2,668	2,667	2,618	2,694	2,591
CO_2 (mol %)	13.4	12.0	7.4	0.4	14.6
GOR flashed (scf/stb)	897	798	848	507	N/A
Oil API	32	32	32	28	N/A
Dew Point (psia)	N/A	N/A	N/A	N/A	3,551 @ 69°C

3.1.2 Field Development and Production Profiles

Sangomar is being developed in a phased approach, with Phase 1 focused on the less complex high quality S520 reservoir, with smaller scale developments of the S540, S460 and S480 reservoirs having an evaluation component. Phase 1 has 23 development wells and provides pre-investment in the FPSO and subsea infrastructure that will support later phases.

The development plan for the S520 consists of six horizontal producers and six horizontal peripheral water injectors located close to the OWC (Figure 41). Injectors and producers are expected to have between 750 m and 1,500 m of reservoir section open to flow. The development plan for the S540 reservoir consists of a high-angle production well and a gas injector in the aquifer to dispose of Phase 1 gas and potentially to provide some pressure support. The S540 reservoir is expected to have a strong aquifer and the primary drive mechanism is natural aquifer influx.

Figure 41: Sangomar Development Well Locations in S520 (Left) and S460 (Right) Reservoir



Source: Woodside

Woodside has recently adjusted the arrangement of producers to five (from six) in the S520 and two (from one) in the S540. The extra producer in the S540 is also the first development well (originally SNE-P-F-520 in Figure 41, now SNP-20), which has been drilled, penetrating all reservoirs as expected and completed with a horizontal section in the S540 reservoir late in 2021. Additionally, several batch wells have been drilled to top reservoir, and one has been drilled through the crest of the S520, confirming the absence of a gas cap late in 2021. Woodside advised that as at 31st December 2021, development well SSP-16 had landed in the S520 reservoir.

S460 and S480 have the highest STOIIP but expected recovery factors are lower and more uncertain than in the S520. The Phase 1 development concept for the S460 and S480 reservoirs consists of injector-producer pairs with parallel horizontal sections (one pair in the S460 and three pairs in the S480). In the S480 reservoir, the horizontal sections are oriented approximately ESE-WNW, i.e. transverse to the strike direction of sandstone waves to maximise the exposure of each injector and producer pair to multiple common sandstone packages (Figure 41). The proposed horizontal reservoir section for these wells is 1,500 m. Woodside advised that as at 31st December 2021, development well SSG-05 had landed in the S460 reservoir.

Phase 1 had FID in January 2020 with first oil scheduled for 2023. A gas injector in the S460 is planned to re-inject Phase 1 gas.

Reserves are attributed to Phase 1 of the Sangomar development. However, the efficacy of a waterflood in the S400 reservoirs has not been demonstrated and there are no analogue fields with successful waterflood to rely on. Therefore, Reserves for the Phase 1 development of the S400 reservoirs have been assigned for a depletion case only, with the balance of the estimated volumes recoverable from a waterflood being classified as Contingent Resources, the contingency being the successful demonstration of waterflood performance.

Phases 2 to 5, with 32 additional development wells, are expected to start production from 2027 and will exploit the S460 and S480 reservoirs further. Pending modifications introduced using learnings from Phase 1, eight injector-producer pairs are planned for S460 and seven pairs for S480. An additional gas injector is also planned for S460 in

Phase 2. Contingent Resources are attributed to Phases 2 to 5. Phases 1 to 5 comprise the Full Field Development of Sangomar.

Concurrent with Phases 2 to 5 is the development with three wells and export of the associated and non-associated gas (the "Gas Export" project). Three additional gas production wells are envisaged in the S410 reservoir to supplement solution gas and provide a nominal gas export rate of approximately 70 to 80 MMscfd. The FPSO has been designed to accommodate the Gas Export project with little modification. However, many contingencies remain to be addressed, including definition of a market, pipeline export routes, gas sales contracts and flow rates. Contingent Resources are attributed to the Gas Export.

Beyond the Full Field Development, further long term opportunities for infill drilling, enhanced oil recovery, development of minor reservoirs (S440 and S470) and exploration opportunities might be considered. No Contingent Resources are currently attributed to these notional developments.

Estimates of STOIIP and technically recoverable resources (TRR) for the Phases as per Woodside's latest estimates are shown in Table 36. As described in previous sections, the exploitation plan has recently been modified by the replacement of a S520 production well with a S540 production well. The effect of this change and the results of the initial wells drilled late in 2021 are not reflected in the volumetric estimates shown in Table 36, as Woodside is currently evaluating the information. However, the results of drilling thus far are positive and therefore GaffneyCline has accepted the field level estimates of recoverable volumes shown in Table 36 as a basis for reporting Reserves and Contingent Resources.

Table 36: Sangomar Estimates of Recoverable Volumes for Phased Development

Case	Reservoir	STOIIP (MMBbl)	TRR (MMBbl)			Recovery Factor	
			Phase 1	Phases 2-5	Full Field	Phase 1	Full Field
Low	S460	1,105	11	51	62	1%	6%
	S480	1,142	32	55	87	3%	8%
	S520	273	117	0	117	43%	43%
	S540	114	2	0	2	2%	2%
	Total	**2,634**	**162**	**106**	**268**	**6%**	**10%**
Best	S460	1,771	14	121	135	1%	8%
	S480	1,321	42	131	173	3%	13%
	S520	374	170	0	170	45%	45%
	S540	129	6	0	6	4%	5%
	Total	**3,595**	**231**	**253**	**484**	**6%**	**13%**

Source: Woodside

Sangomar is being developed with an FPSO connected to the subsea production system by flexible risers. The subsea infrastructure will consist of two 8" nominal diameter production flowline loops to the north and south of a large canyon on the sea-floor. Eighteen of the 23 Phase I wells are on the southern loop. The FPSO is a 100 Mbopd capacity double-hulled VLCC-conversion with a total liquids capacity of

130 Mblpd and will be permanently turret moored in the eastern side of the field in water depth of 780 m for the duration of the field life.

The produced gas will be processed and used as fuel and for lifting oil production and the excess gas will be reinjected in Phase I. The FPSO will have a gas handling capacity of 130 MMscfd with the ability for backflow to the FPSO for start-up gas or for associated and non-associated gas to be supplied to shore for a later gas export. In addition to the Phase 1 wells, the FPSO has flexibility for 65 more wells. COVID-19 has delayed the VLCC donor vessel arrival at the conversion yard, but the FPSO execution schedule remains on schedule to achieve first oil in 2023.

3.1.3 Cost Estimates

GaffneyCline has reviewed a range of project cost and supporting documentation provided by Woodside.

The CAPEX appears to be reasonable, based on GaffneyCline's experience. CAPEX for the 1P and 2P Reserves cases is shown in Table 37. The potential benefit of water injection in the S460/480 reservoirs has been excluded from the Reserves cases, and accordingly the Phase 1 CAPEX has been adjusted down to include only the cost of one of the four intended S460/480 water injectors. Note that all four injection wells are intended to be drilled in Phase 1 of the current development plan. Any benefit from the effectiveness of the waterflood of the S460/480 reservoirs is accounted for in the Contingent Resources.

Table 37: Sangomar Gross CAPEX Estimates for Reserves

Phase 1 (US$ MM)	2022	2023	2024
Drilling and Completion CAPEX	556	370	35
FPSO CAPEX	398	220	-
Subsea and Pipelines CAPEX	282	31	4
Project Owners Costs & General CAPEX	155	154	32
Total	**1,391**	**775**	**71**

Gross CAPEX for development of the Sangomar Contingent Resources case is estimated to be US$6,157 MM.

The OPEX estimates for the development were evaluated by GaffneyCline, taking into consideration the planned activities and work programs outlined in the documentation. The total OPEX comprises of FPSO, drilling and completion, and subsea and pipelines, of which the FPSO contributes most significantly to the total OPEX.

FPSO OPEX is broken down into fixed (including crew and routine maintenance), variable (including marine services and FPSO chemicals) and Woodside operator costs (including Senegal in-country costs).

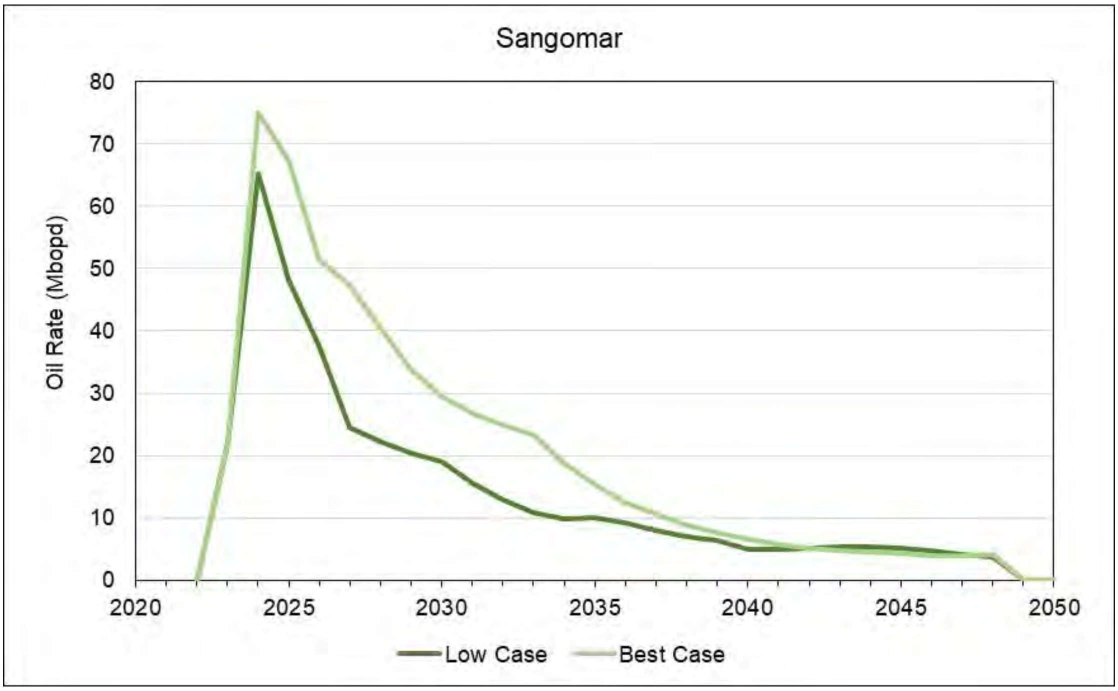
The OPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. The Phase 1 OPEX profiles have been adjusted in the 1P and 2P Reserves cases to reflect the anticipated reduction in OPEX due to the inclusion of only one of the four intended S460/480 water injectors in the Reserves case. Further adjustments have been made to OPEX to account for changes in the variable OPEX components of the FPSO, drilling and completion and subsea and pipelines OPEX costs resulting from differences between the Woodside production profiles compared with the GaffneyCline profiles.

For the Reserves cases, the Phase 1 ABEX has been adjusted to account for the inclusion of only one of the four intended S460/480 water injection wells.

3.1.4 Reserves and Contingent Resources

Oil Reserves are attributed to the Phase 1 development, scheduled to start production in 2023, excluding the potential benefit of the water injection in the S400 reservoirs. The Low and Best estimate estimates of gross recoverable volumes before imposing economic cut-offs are 143 and 204 MMBbl and the profiles are shown in Figure 42. Gas CiO volumes are estimated to be ~86 Bscf.

Figure 42: Sangomar Oil Production Profiles for Phase 1 Reserves Cases



Contingent Resources are attributed to the effective waterflood of the S400 reservoir of Phase 1 (Development Pending) and for development Phases 2 to 5, which are contingent on the performance of the S400 reservoirs during Phase 1 and scheduled to commence production in 2027/2028 (Development Unclarified) (Table 38). Contingent Resources are also attributable to a gas export project under evaluation and potentially commencing production in 2027, notionally delivering 72 MMscfd to shore for a period of 13 years or more (Development Unclarified).

Table 38: Sangomar Gross 2C Contingent Resources as at 31st December 2021

Project	Gross 2C Contingent Resources		Development Status
	Oil / Condensate (MMBbl)	Gas (Bscf)	
Phase 1 effective waterflood	27	-	Pending
Phases 2 to 5	253	-	Unclarified
Gas Export	8	367	Unclarified
Total	**288**	**367**	

3.1.5 Infrastructure, Health, Safety and Environment

GaffneyCline has reviewed the environmental protection documentation provided by Woodside and has concluded that the documents are comprehensive and fit for purpose for such a development. The documents have systematically identified and assessed the significant environmental and socio-economic impacts associated with the development activities including any potential accidents and approved by the Senegalese Ministry of Petroleum and Energy. A decommissioning philosophy is mentioned, but further granularity will be required closer to the time, which can be managed through supplementary impact assessments and updates to project risk registers. The other relevant documentation reviewed by GaffneyCline is generally comprehensive and robust and provides confidence that the project will be able to meet the required standards.

Personnel will be transported to the offshore location by helicopter, which will be chartered from existing facilities at Dakar's Blaise International Airport, as well as by marine transfer with FPSO modifications included for this option. The Dakar multi-users' logistics and supply base is already developed and currently supports the drilling campaign.

GaffneyCline has reviewed the extensive Human Resources related documentation including the Sangomar Local Content Strategy, Code of Conduct, Whistleblower Policy, Anti-Bribery and Corruption Policy, Human Rights Policy, Diversity and Inclusion Policy. All the documents reviewed are comprehensive and provide assurance that policies and legislation are being followed, that the employee rights and responsibilities are protected with clear monitoring, evaluation and reporting structures.

GaffneyCline has also reviewed the Occupational Health and Safety documentation which is mainly covered in the ESIA (Section 10) as well as the Sangomar Project Health, Safety and Environment Management Plan, Woodside's Health, Safety, Environment and Quality Policy and the Sangomar Field Development Oil Pollution Emergency Plan. In addition, the ESIA covers Community Health and Safety relating to coastal communities as well as other marine users operating in the vicinity of the offshore area. The HSE documentation demonstrates a sound understanding of the HSE risks associated with the project.

3.2 FAN Discovery

The FAN discovery (well FAN-1) lies to the north-west of the Sangomar Field within the EAA and oil was encountered in Cenomanian aged sandstone, i.e. in different formations to the Sangomar Field. The reservoirs are generally thinly bedded and have low porosity and permeability. A second well, FAN South-1, was drilled to the south of the FAN-1 discovery and encountered hydrocarbons in a pressure isolated accumulation. The multi-azimuth seismic is expected to provide information on the distribution of the reservoir in the FAN discovery. If this interpretation is encouraging, it is anticipated that the discovery will be appraised, with potential to develop it as a satellite to Sangomar. Currently, nominal 2C gross Contingent Resources (Development Unclarified) of 90 MMBbl are attributed to FAN. Estimates of recoverable volumes for FAN are subject to a very wide range of uncertainty.

4 Woodside Canada

Woodside has an interest in a single asset in Canada, the Laird unconventional gas discovery.

4.1 Liard Basin Unconventional Gas (Canada)

Through its subsidiary Woodside Energy International Canada, Woodside holds a 50% non-operated working interest in unconventional gas discoveries in the Liard Basin, located approximately 800 km northwest of Calgary, Alberta in northwest British Columbia (Figure 43). Woodside acquired Apache Canada Ltd.'s interest in the Liard Basin in April of 2015 as well as a 50% interest in the proposed Kitimat LNG (KLNG) facility at Bish Cove in British Columbia. Woodside transferred its role as upstream operator to Chevron in May 2015. Following relinquishments of 10 leases due for expiry late in 2020, the remaining acreage is restricted to a "Core Area", covering approximately 1,700 km^2 which would be the focal point of any future development. Chevron, the operator, has until recently held the remaining 50% in both KLNG and the Liard Basin unconventional gas discoveries.

Development of the Liard Basin unconventional gas was intended to provide feedstock to the proposed KLNG facility via the existing third party regional pipeline network and a proposed 480 km Pacific Trail Pipeline. However, Chevron announced its intention to divest its 50% interest in KLNG in December 2019 and this was followed by Woodside announcing in May 2021 that it also intends to exit its 50% non-operated participating interest in KLNG. The exit includes divestment or wind-up and restoration of assets, leases and agreements covering the 480 km Pacific Trail Pipeline route and the site for the proposed LNG facility at Bish Cove. This is ongoing.

Figure 43: Location Map of Liard Basin

Source: Woodside

Further work on the development of the Liard Basin unconventional gas has been suspended and Chevron has been relinquishing infrastructure-free leases, in accordance with its broader KLNG exit activities. However, Woodside announced that while it intends to exit KLNG, it intends to retain its upstream position in the Liard Basin, to investigate potential future natural gas, ammonia and hydrogen opportunities. This entails Woodside taking on those infrastructure-free leases (29 in total) at 100% as Chevron relinquishes. Woodside expects that the transfer of the 29 leases will be completed in Q1 2022. Woodside has indicated that all applicable leases have been included under a proven resource mechanism and require no further appraisal drilling, and allowing unlimited annual renewals beyond the initial 10-year period, with minimal annual renewal payments (of ~US$0.7 MM). Leases with infrastructure remain jointly held, with Chevron as Operator.

GaffneyCline has classified the unconventional gas in the Liard Basin as Contingent Resources “Development Not Viable” on the grounds that there are no plans to develop or acquire additional data for the foreseeable future.

The Kotcho Shale Formation, the reservoir for the unconventional resources, is approximately 200 m thick and is deeply buried, at ~4,500 mss. It has high pressure of ~15,000 psia and high temperature of ~170°C. The gas is dry, comprising ~92% methane and ~8% carbon dioxide. A total of 11 exploration and appraisal wells have been drilled, six of which have been stimulated in the Kotcho Shale and put on production for various lengths of time. Woodside has indicated that a total of ~74 Bscf of gas has been produced. All wells have been shut-in since June 2019, with three suspended for potential future completion. Fracturing with up to 19 stages has been implemented successfully in two of the appraisal wells. Peak rates of up to 60 MMscfd were achieved and analysis of the production and test data by third party specialists has led to estimates of ultimate recoverable volumes per well (over 30 years) ranging from 30 to 170 Bscf.

There is a reasonable database for the Kotcho Shale Formation from seismic data and well penetrations as well as experience with fracturing and producing from the formation. A 3D seismic survey is available over the core area and this is supplemented with a good quality 2D seismic dataset. The Kotcho Shale Formation is well defined by seismic data, and extends beyond the licence area. GIIP for the development area within licence has been estimated from reservoir properties measured in the wells and extrapolated and interpolated from the well data. Woodside has estimated the GIIP to be approximately 51.6 Tscf within the development area. The formation is interpreted to have porosity of 1% to 7% and permeability of 12 to 360 nD (0.000012 to 0.000360 mD).

The conceptual development plan prepared by Chevron prior to its decision to exit was to supply feed to the proposed KLNG plant from the Liard core area with some 380 multi-stage fractured horizontal wells. While this concept is no longer relevant, the technical work undertaken to evaluate the envisaged project provides a basis for estimating potential recoverable volumes from Liard.

Woodside has used production data from the appraisal wells to develop well type curves, comprising estimates of initial well rates, decline rates and recovery per well, combined with assumptions of well spacing and drainhole length. Woodside has estimated the potential ultimate recovery from the field to be ~30.3 Tscf, corresponding to a recovery factor of 59%. After deductions for fuel and flare and for non-saleable non-hydrocarbons, the Best estimate gross sales volume is ~26.7 Tscf. Woodside's working interest 2C Contingent Resources, based on 50% equity are 13.35 Tscf. Woodside has indicated that its equity will be 94.9%, once all the infrastructure-free leases have been transferred.

While the production forecasts and estimates of recoverable volumes have been based on data acquired from the field, there is much uncertainty in the way the field might be developed in the future and in the estimation of Liard Basin recoverable volumes.

No robust analogues for the Liard Basin reservoirs have been identified with characteristics of depth and pressure similar to the Kotcho Shale Formation reservoirs from which to draw experience. Based on information provided by Woodside of other shale gas resources, GaffneyCline notes that Woodside's estimates of recovery factor and recovery per well for Liard (~80 Bscf) appear to be high, although the high pressure of the formation and the leanness of the gas are favourable characteristics for recovery. Nonetheless, the absence of valuable liquids in the produced wellstream and the high cost of drilling due to depth reduce the attractiveness of the development of Liard. Uncertainty in the estimated resources is secondary to the project risk, i.e. the chance of development, which GaffneyCline estimated to be less than 15%.

5 Woodside Global Exploration Portfolio

Woodside's global exploration portfolio consists of assets in Australia, Senegal, Korea and Congo. They contain prospects and leads ranging from NFE opportunities in Australia and Senegal to stand-alone exploration projects in Australia, Korea and Congo.

All of the prospects/leads discussed here could potentially be drilled within the next five (5) years; additional prospectivity with no firmly planned drilling has been excluded from the assessment.

5.1 Australia

The majority of Woodside's exploration portfolio is in Australia (Table 39). The prospects and leads are all gas and are located in the mature and well drilled sub-basins of the Northern Carnarvon Basin; with most located reasonably close to developed fields or at least to currently undeveloped discoveries.

Table 39: Woodside's Australian Exploration Portfolio

Sub-Basin	Permit	Woodside Equity	Prospect Name	HC Type	Drill year
Barrow	WA-356-P / WA-536-P	65%	Carey South	Gas	2023
Barrow	WA-536-P	65%	Carey North	Gas	2025
Barrow	WA-49-L	65%	Gemtree	Gas	2023
Barrow	WA-49-L	65%	Penfolds	Gas	2024
Dampier	WA-5-L	16.70%	Castor Deep	Gas	2024
Exmouth Plateau	WA-404-P	100%	Armagnac	Gas	2024
Exmouth	WA-28-L	62%	Norton East	Gas	2022

The four assets in the Barrow sub basin, i.e. Carey South, Carey North, Gemtree and Penfolds, are located in the proximity of Brunello, Julimar, Pluto, Xena, and Iago gas producing fields, and are covered by 3D seismic data. The prospects target the Triassic age Mungaroo Formation, which has been proven to be productive in the area. The assets are considered to have relatively high chance of geologic success, with the remaining risks in specific prospects generally related to trap integrity and/or reservoir quality. Woodside plans to drill these assets in year 2023 to 2025, although the stated drill chance varied from 25% to 75%. The gas resources are generally envisioned as a backfill to the Wheatstone project, with tieback to the Brunello platform.

Castor Deep is located within the area of the North West Shelf gas producing fields, and targets the Late Triassic age sandstone reservoirs of the Mungaroo and Brigadier Formations. The prospect is covered by 3D seismic data and shows bright amplitudes at the reservoir levels. The chance of geologic success for the prospect is considered relatively high, with the reservoir effectiveness and trap integrity considered as the remaining risks. Currently, Woodside plans to drill the asset in 2024, with 25% chance of drill. The envisioned development is a pipeline to the nearby producing NWS platform.

Armagnac is a gas prospect identified through strong amplitude response in 3D seismic data. Located in the Exmouth Plateau, the prospect targets the Triassic age sandstone reservoir of the Mungaroo Formation, in a combined structural and stratigraphic trap. The chance of success of the prospect is elevated by the presence of strong seismic attributes. Woodside's current plan places the drill year for Armagnac at 2024, with 50% chance of drill. Several gas discoveries of similar type have been found within the same permit, but none of these have been developed.

Norton East, located in the Exmouth sub basin, is a gas prospect with a three-way dip closure trap identified through 3D seismic data. The prospect is located in the proximity of several currently producing oil and gas fields of the Greater Enfield area. The prospect targets several sandstone reservoirs of the Early Cretaceous and Late Jurassic, which have been found to be productive in the area. The chance of geologic success of the prospect is considered relatively high, with remaining risks in the reservoir quality and trap integrity. Woodside's current plan is to drill the prospect in 2022, with 25% chance of drill. The conceptual development plan is a subsea tieback to the nearest Greater Enfield facility.

5.2 Senegal

The SNE North oil prospect lies to the north of the Sangomar Field offshore Senegal. The Sangomar Phase 1 development is currently underway and the SNE North prospect is expected be drilled during the current drilling campaign (2H 2022). The prospect is assessed by Woodside to have a high chance of geologic success as hydrocarbons within the mapped closure have been established by the SNE North-1 exploration well which demonstrated the presence of gas in a separate accumulation to the Sangomar Field. The next well is designed to test the potential for an oil-leg below these gas bearing reservoirs.

The SNE North Prospect has been mapped using the recently reprocessed Maz 3D seismic data and the Prospective Resources estimates are based on the interpretation of these data. GaffneyCline has reviewed the Prospective Resources and associated chance of geologic success and finds them to be robust estimates.

If the exploration well is successful, it is anticipated that the discovery will be developed as a subsea tie-back to the Sangomar Field FPSO.

5.3 Congo

Woodside has a 42.5% working interest (50.0% paying interest) in deep water Block Marine XX offshore Congo, operated by TotalEnergies. The block was awarded following the 2016 Bid Round. Woodside has a 50% working interest. Woodside has an exploration well commitment and is currently planning to drill the Niamou Marine prospect in 2023 (drill chance 50%).

The Niamou Marine prospect is a large sub-salt closure mapped on 3D seismic data. In the maximum case, the mapped closure extends into Gabon's offshore acreage. The prospect is located in 2,400 m water depth.

Woodside has considered both oil and gas cases (50:50 chance factor), based on basin modelling and potential source rock kinetics. The gas case is evaluated as uneconomic, and the oil gas is marginally economic even at very high resource volumes.

The critical issue in the evaluation of the Niamou Marine prospect is reservoir quality and therefore recovery per well. In the current model the well count is high (reflecting the relatively low reservoir quality) and this with the water depth of the prospect.

The project currently fails to meet Woodside corporate metrics.

5.4 Korea

Woodside's Korean exploration portfolio comprises Blocks 8 and 6-1N, where Woodside holds 50% working interest. The Blocks contain two Leads located in the northern part of the Ulleung Basin, which is an immature, deepwater, Neogene back-arc basin, located east of the Korean peninsula. The leads are located in about 2,000 m water depth, some 50 km north of the currently producing gas field, Donghae-1. Of the two wells nearest to the leads (20 km away), one was a dry hole and one, Hongge-1, was a sub-commercial discovery, encountering gas within Middle Miocene sandstone reservoirs.

The Daege and Jibgae leads were identified based on 2008 vintage 2D and 2014 vintage 3D data; however, a new set of 3D seismic data was acquired in 2021 and is being integrated in the interpretation of the leads. The two leads are considered high risk and are at the immature stage of the exploration. Woodside's current plan places one well in each lead, with the Daege well given a 75% chance of drill and the Jibgae well a 25% chance of drill. The conceptual development plan involves a subsea tieback to a greenfield onshore domestic gas plant.

BHP Petroleum Assets

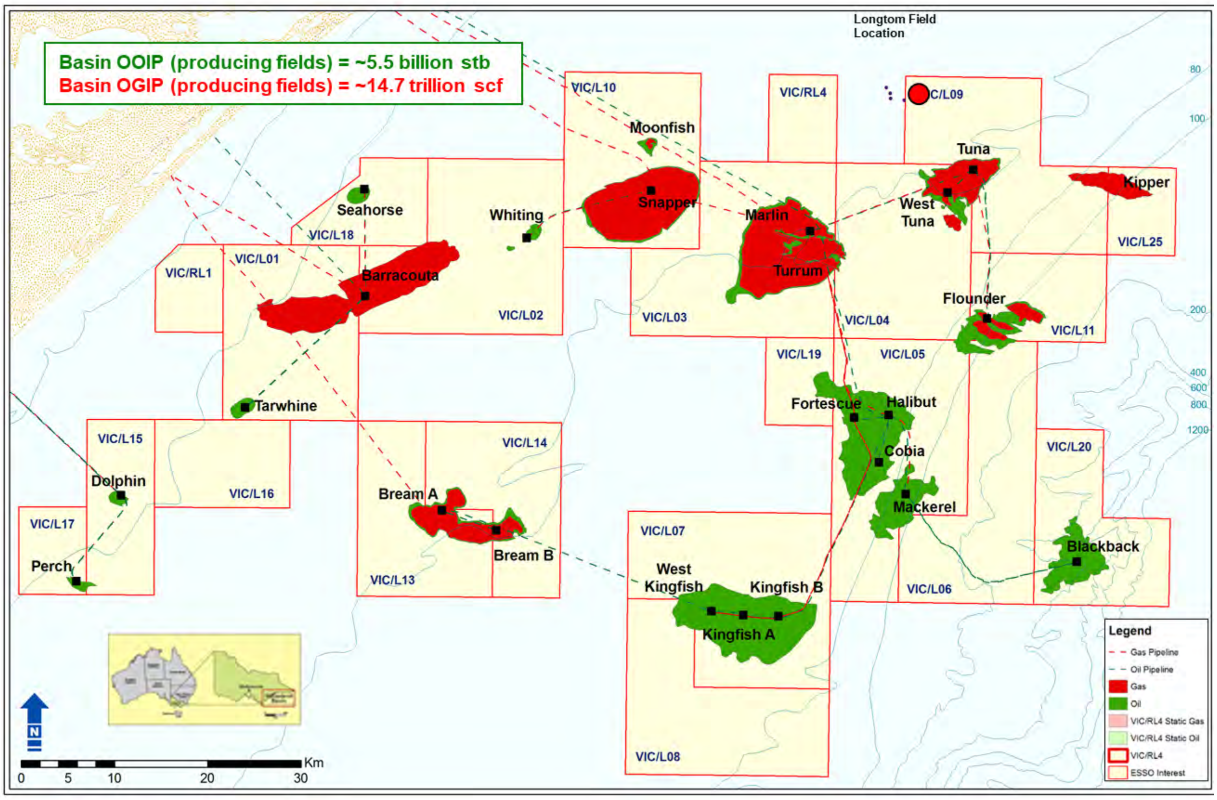
6 BHP Petroleum Australia

BHP Petroleum has interests in the NWS gas and oil projects, and in the Scarborough LNG project (including the Jupiter and Thebe fields). Woodside also has interests in these assets and they are described in Section 1.1 (NWS) and in Section 1.5 (Scarborough, Jupiter and Thebe), and are not repeated here. The remainder of BHP Petroleum's Australian assets are described below.

6.1 Bass Strait

The Bass Strait oil and gas fields (Figure 44) are located within the Gippsland basin, offshore the south-eastern margin of Eastern Victoria, Australia. BHP Petroleum has interests in a total of eleven gas fields, four of which have oil rims, and 13 oil fields.

Figure 44: Oil and Gas Fields of the Gippsland Basin

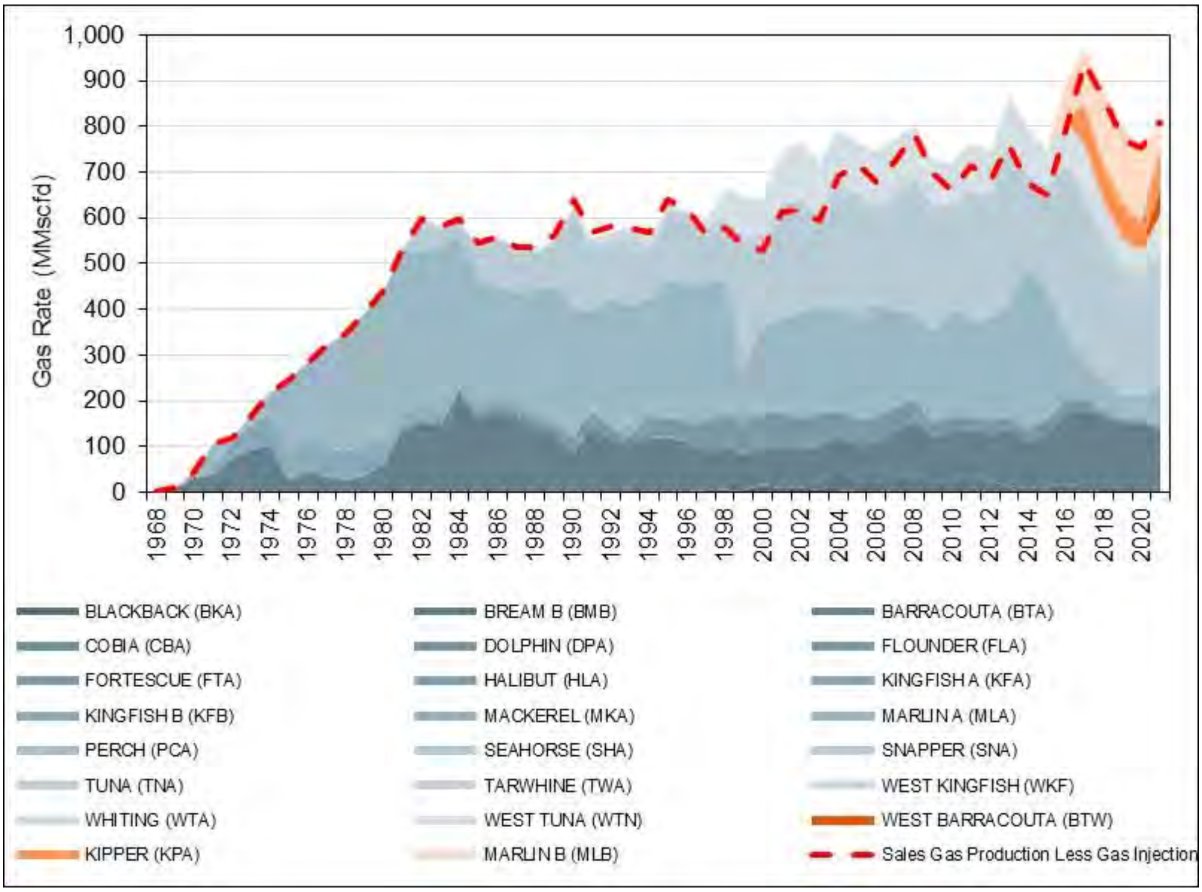


Source: BHP Petroleum

6.1.1 Field Description

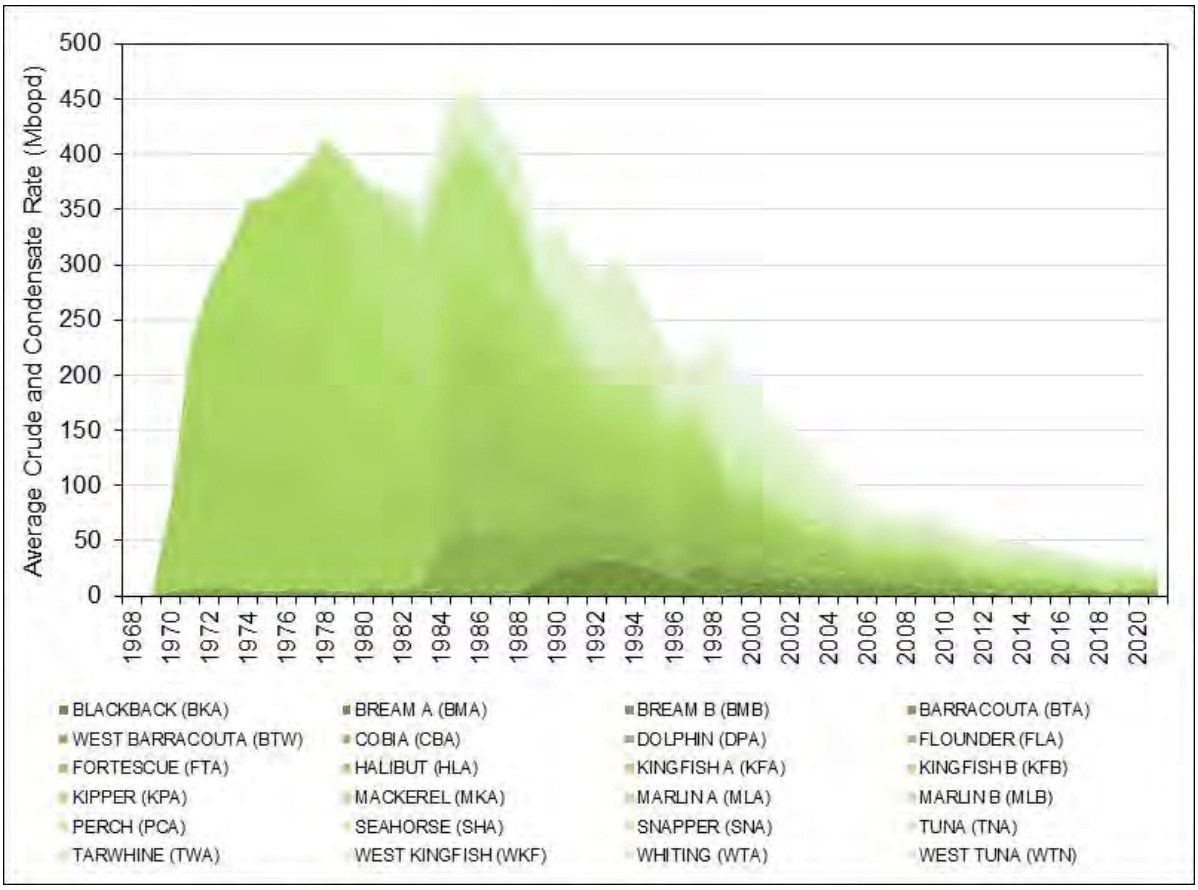
Based on the data provided by BHP Petroleum, during the latter part of 2021 the fields produced at aggregated rates of ~830 MMscfd of sales gas, 26 Mbpd of oil/condensate and 36 Mbpd of NGL, with the majority of current gas production coming from the Snapper, Barracouta, Tuna, Turrum and Kipper fields (Figure 45 and Figure 46). There is significant seasonal variation in gas demand in Victoria with greater gas demand in the winter months compared to the summer months.

Figure 45: Bass Strait Historical Gas Production



Source: GaffneyCline from BHP Petroleum data

Figure 46: Bass Strait Historical Oil and Condensate Production



Source: GaffneyCline from BHP Petroleum data

BHP Petroleum's Bass Strait assets can be grouped into five predominantly gas producing hubs (Barracouta, Snapper, Marlin/Turrum, Tuna/West Tuna & Kipper Hub), and a group of oil fields slightly further offshore (Figure 44). A list of BHP Petroleum's fields and projects is shown in Table 40. The list includes producing oil and gas fields and a large number of projects that are in various stages of evaluation and maturity, as well as several depleted fields. Seven additional depleted oil fields are not included in Table 40.

Reserves are attributed to the producing gas and oil fields. Four projects (North Turrum, Wirrah, Sweetlips and East Pilchard) are relatively mature Contingent Resources.

With the exception of Kipper, which is governed by the Kipper Unit Joint Venture in which BHP Petroleum has 32.5% interest, the rest of the fields are governed by the Gippsland Basin Joint Venture which consists of Esso (50%) and BHP Petroleum (50%) with Esso as the operator.

Table 40: Bass Strait Fields Summary (from BHP Petroleum)

Main Platform / Hub	Fields	Field Type	Development Status
Barracouta Hub	Barracouta	Producing Main Gas Field	Producing
	BTA West	Producing Main Gas Field	Producing
	BTA Deep Gas	Tight Deeper Sands of Main Field	Development Not Viable
	Whiptail	Barracouta Satellite Oil Field	Development Not Viable
	Mulloway	Barracouta Satellite Oil Field	Development Not Viable
	Tarwhine Prod	Barracouta Satellite Oil & Gas Field	Development Not Viable
	West Whiptail	Barracouta Satellite Oil Field	Development Not Viable
	Luderick	Barracouta Satellite Oil & Gas Field	Development Not Viable
Snapper Hub	Snapper	Producing Main Gas Field	Producing
	Snapper Deep	Tight Deeper Sands of Main Field	Development Not Viable
	Moonfish	Producing Oil & Gas Field	Producing
	Moonfish Gas N1.9	Producing Secondary Gas Field	Producing
	Moonfish W	Snapper Satellite Gas Field	Development Not Viable
	Wirrah	Snapper Satellite Oil & Gas Field	Development Pending
	Sweetlips	Snapper Satellite Gas Field	Development Pending
	Whiting	Snapper Satellite Oil & Gas Field	Development Uncertain
	Emperor	Snapper Satellite Oil & Gas Field	Development Not Viable
Marlin / Turrum Hub	Turrum	Producing Main Gas Field	Producing
	Turrum - Marlin N-1	Producing Secondary Gas Fields/Reservoirs	Producing
	North Turrum	Turrum Phase 3 (5 Well Development)	Development Pending
	SE Remora	Turrum Satellite Oil & Gas Field	Development Not Viable
	Remora	Turrum Satellite Oil & Gas Field	Development Not Viable
	Sunfish	Turrum Satellite Oil & Gas Field	Development Not Viable
Tuna / West Tuna Hub	Tuna M-1	Producing Main Gas Field	Producing
	Tuna Other	Producing Secondary Oil & Gas Fields	Producing
	Tuna-C-Gas	Tight Deeper Sands of Main Field	Development Not Viable
	SE Longtom	Tuna Satellite Gas Field	Development Not Viable
	Angelfish	Tuna Satellite Gas Field	Development Not Viable
	Flounder	Tuna Satellite Depleted Oil & Gas Field	Development Not Viable
Kipper Hub	Kipper	Producing Main Gas Field	Producing
	East-Pilchard	Kipper Satellite Gas Field	Development Unclarified
	Scallop	Kipper Satellite Oil & Gas Field	Development Not Viable
	Grunter	Kipper Satellite Oil & Gas Fields	Development Not Viable
Oil Fields	West Kingfish	Producing Oil Field	Producing Oil
	Cobia	Producing Oil Field	Producing Oil
	Halibut	Producing Oil Field	Producing Oil
	Central Fields		Development Not Viable
	Yellowtail	Cobia Satellite Oil Field	Development Not Viable
	Gudgeon	Cobia Satellite Oil Field	Development Not Viable

Produced wet gas is transported via pipeline to Esso's Longford gas plant in Gippsland, Victoria, where the gas is processed and dried. Sales gas (mainly methane and ethane) is sold to the domestic market. Condensate is knocked out at the offshore platforms where it is combined with crude produced from the Kingfish, Cobia and Fortescue fields and sent to the Longford crude stabilization plant. From Longford, stabilized crude & condensate and LPG are further piped via a 187 km long pipeline to the Long Island point facility at Hastings, Victoria, before being further processed and sold.

6.1.2 Field Development and Production Profiles

Reserves associated with most of the Bass Strait fields were based on production forecasts generated from BHP Petroleum's Bass Strait Network model, an integrated subsurface and surface network model that incorporates reservoir material balance and flow throughout the production system, accounting for production constraints from each part of the network. This is coupled to a plant model, tuned to match the liquid yields from the prior two years, to calculate forward estimates of NGLs and condensate.

GaffneyCline reviewed BHP Petroleum's Bass Strait Network and plant models and carried out its own verification runs to confirm appropriateness of the forecasts. GaffneyCline generated a set of production forecasts used as the basis for estimating Reserves.

Individual fields have been grouped into the five main producing hubs and other oil fields (Table 40). GaffneyCline carried out further checks specific to the individual major fields (Barracouta, Snapper N1, Turrum L, Tuna M-1 and Kipper).

Barracouta

The Barracouta N-1 gas field was the first offshore field discovered in Australia, in 1965, and gas production started in 1969. More recently, in 2021, West Barracouta was developed via a 2-well subsea tieback.

The main depositional environment is coastal braid plains comprising high NTG fluvial sands with interbedded shales and extensive coals, as well as beach/shoreface successions comprising high NTG shoreface sands with localized dolomitisation. The field features excellent reservoir properties, with mean porosity ~23 to 30%, mean permeabilities ranging from 1 to 10 D. Production is from a thick gas column (~140 m gross), with an oil rim (~8 m), supported with strong bottom water drive.

Gross cumulative production is ~2 Tscf of sales gas, 32 MMBbl of condensate and 88 MMBbl of NGLs, coming from 10 producing wells in Barracouta, and 2 subsea tiebacks in West Barracouta. Currently, most of (East) Barracouta has been produced and the gas that remains is mainly attic gas.

Recent drilling results in West Barracouta were better than expected, which resulted in an increase in the remaining gas in place from the pre-drill estimates of 164 Bscf (Low) and 225 Bscf (Best) to 246 Bscf (Low) and 437 Bscf (Best). There are no plans for future development in Barracouta or West Barracouta. Estimates of remaining gas in place and remaining recoverable volumes are summarized in Table 41.

GaffneyCline has reviewed the supporting technical work and these estimates appear reasonable.

Table 41: Barracouta N-1 Gas Field Remaining GIP and Remaining Recoverable Volumes

Reservoir	Category	Remaining GIP (Bscf)	Remaining Recoverable Gas (Bscf)
BTA N-1 (East)	Low	106	48
	Best	168	97
BTA N-1 (West)	Low	246	138
	Best	437	288

Notes:

1. GIP for BTA N-1 (East) only considered attic volumes above the GWC.
2. BTA N-1 (West) only came onstream in April 2021.

Snapper N-1/Moonfish

The Snapper N-1 gas field was discovered in 1968, and started production in 1981. A small satellite field to the north of Snapper called Moonfish was also developed from the Snapper platform.

The main depositional environment is Eocene aged amalgamated fluvial sandstones. The field features excellent reservoir properties, with mean porosity around 25%, mean permeability ranging from 1 to 10 D. Production is from a thick gas column (max. 200 m gross), with an oil rim (~6 to 7 m) and is supported by strong bottom water drive.

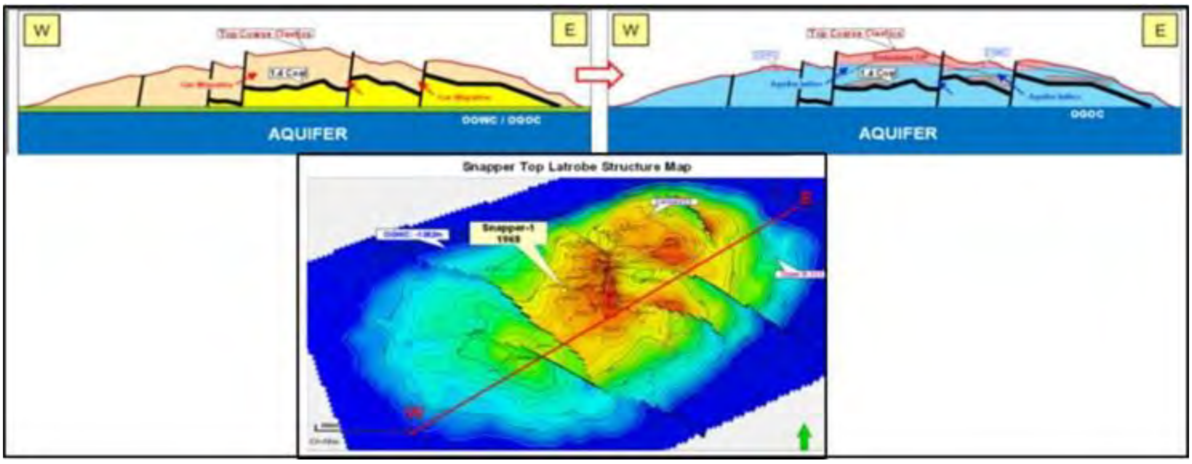
As of 1st July 2021, gross cumulative production is 2.57 Tscf of sales gas, 51.0 MMBbl of condensate and 93.9 MMBbl of NGLs, coming from 27 producing wells.

Similar to East Barracouta, most of the gas from the Snapper field has been produced and mostly attic gas remains in the N-1 upper sands. Reservoir monitoring has indicated that there are variable contacts across the field, along with some minor pockets of gas usually below coals. Figure 47 shows a schematic cross section of the field, which provides a visual indication of the movement and current interpretations of the gas water contact.

Snapper is a mature producing field with good coverage from 45 wells. There is also an abundance of historical pressure data, as well as GWC surveillance in recent years to help constrain the forecasting model. Uncertainties in the material balance model relate mostly to parameters such as trapped gas saturation and sweep efficiency. There are no plans for future development in Snapper.

Production forecasts are based on material balance models which feed into the integrated Bass Strait Network model. Remaining GIP and estimates of remaining recoverable volumes are summarized in Table 42. GaffneyCline has reviewed the supporting technical work and these estimates appear reasonable.

Figure 47: Snapper Field Schematic and Contact Movement



Source: BHP Petroleum modified by GaffneyCline

Table 42: Snapper Field GIIP, Remaining GIP and Remaining Recoverable Volumes as at 31st December 2021

Reservoir	Category	GIIP (Bscf)	Remaining GIP (Bscf)	Remaining Recoverable Gas (Bscf)
N+1 and Gurnard	Low	3,409	372	205
	Best	3,868	513	317

Turrum L

The Turrum L gas field was discovered in 1966, and started production in 1997 via two Marlin-A platform recompletes. In 2004, a five well Phase 1 oil development commenced production targeting the L500 oil sands. In 2015, the Marlin-B platform was completed as part of the greater Kipper-Tuna-Turrum development together with a five well Phase 2 development, targeting the main L105-L400 gas sands with four of the five wells. The other well targeted the L500 oil sands.

The main depositional environment is Paleocene aged fluvial channel and overbank deposits. The geological system is complex, consisting of stacked reservoir sands, multiple pressure zones and gas water contacts. The sands can broadly grouped into five intervals, namely L60-99, L100, L105-L400, L420 and L500. Of these, the L60-99, L105-400 and L500-510 are currently on production.

The field features highly variable reservoir properties ranging in quality from low/moderate to excellent, with porosity around 12 to 20% and permeability ranging from 50 to 1,500 mD. Production is from a thick gas column (~400 m gross for L105-L400 gas reservoirs, 80-100 m gross for the L500-L520 gas and oil reservoirs). Net-to-gross for the L105-L400 sands is low to moderate, around 15 to 40% net sand. The drive mechanism is depletion drive for the shallower gas sands, and moderate aquifer drive for the deeper oil and gas sands.

Gross cumulative production from the L105-400 reservoir is ~200 Bscf of sales gas, ~6 MMBbl of condensate and ~8 MMBbl of NGLs, coming from four producing gas wells. Gross cumulative production from the L500-510 reservoir is ~82.0 Bscf of free and solution gas, ~9 MMBbl of oil/condensate and ~4 MMBbl of NGLs. The L500-510 oil reservoir was producing until March 2020, after which gas cap blowdown commenced. Production is currently constrained to control sand production. The L60-99 reservoir recently came on stream and as of 31st December 2021 had produced 0.02 MMBbl of condensate, 0.03 MMBbl of NGL and 0.88 Bscf of gas.

Undeveloped Reserves are associated with the future installation of sand control. BHP Petroleum's current assumption is that three wells (B10, 15 &16) will be recompleted with 7" tubing during sand control installation in February 2023, which will then restart at high rates. Undeveloped Reserves include all volumes from 2,500 psi until abandonment since existing geomechanics work shows the onset of shear failure at around 2,500 psi. This is in line with actual field observations from the B4 well where sand was observed. Given that initial reservoir pressure was around 3,600 psia and the depletion drive nature of the field, there are significant volumes associated with production below the current 2,500 psi limit. Table 43 provides a summary of the incremental volumes associated with this sand control project for the main fault block. The Turrum sand control project appears to be firm with a possible six month deferral of the start-up timing associated with overall optimization of Gippsland gas production and plant capacity.

There are also additional workovers planned to install smaller tubing to manage liquid loading due to pressure depletion, which has had the impact of accelerating production and reducing the fuel/flare burden of Turrum. GaffneyCline has also reviewed the inputs and forecasts from BHP Petroleum's MBAL model for Turrum L105-400 and overall, the technical work appears reasonable.

Table 43: Turrum Field Estimates of Gas Recovery With and Without Sand Control as at 31st December 2021

Reservoir	Category	GIIP (Bscf)	Gross Produced Wet Gas (Bscf)	Gross Remaining Recoverable Gas (Bscf)	
				Without Sand Control	Incremental With Sand Control
Main Fault Block (B10, 15 &16)	Low	707	211	55.4	275.9
	Best	830	211	109.1	329.0

Note:

1. Excludes L130L sand.

Tuna M-1

The Tuna M-1 gas and oil field was discovered in 1968. The field commenced production from the oil rim in 1997 with 51 predominantly horizontal oil producers and gas injection in eight wells for pressure support. Subsequently, gas cap blowdown commenced in 2014.

The main depositional environment is marine shale grading upwards through lower shoreface, upper shoreface and estuarine units. The M sand is the main producing reservoir, which features excellent reservoir properties, with mean porosity around

24% and mean permeability ranging from 800 to 3,000 mD. Production is from an 80 m gas cap and an oil rim, originally 12 m thick, but now less than 1 m, assisted by strong edge/bottom water drive.

As of 1st July 2021, gross cumulative production was 194.5 Bscf of sales gas, 12.4 MMBbl of condensate and 25.7 MMBbl of NGLs. Currently, the field is producing mostly gas with minor oil.

Production forecasts are based on material balance models that feed into the Bass Strait Network model. GIIP and recoverable volumes from the tank model are summarized in Table 44.

Pressure and fluid contact data exists to help constrain the material balance forecast models. Even though there is a range of scatter observed in the pressure data, the overall trend is still quite evident. As for the fluid contact, there has been movement associated with pre-production gas cap expansion and gas injection prior to gas cap blowdown. The inputs and forecasts from BHP Petroleum's MBAL model for Tuna M-1 have been reviewed and the history match of pressure and fluid contact has been checked. Overall, the technical work appears reasonable.

Table 44: Tuna Field GIIP and Remaining Recoverable Volumes as at 31st December 2021

Reservoir	Category	GIIP (Bscf)	Produced Gas (Bscf)	Remaining Sales Gas (Bscf)
Tuna M-1	Low	567	175.8	215.4
	Best	667	175.8	281.0

Note:

1. Low and Best Estimate GIIPs are based on deterministic map based assessments. No current static model is available.

Kipper

The Kipper gas field was discovered in 1986. The field commenced production in 2017, tied back to the West Tuna platform.

The main depositional environment comprises coarse-grained braided fluvial deposits that are inter-bedded with flood plain mudstones, within the Golden Beach group. The field features good reservoir properties, with mean porosity around 16% and mean permeability ranging from <100 to 1,000 mD. Production is from a thick gas interval (~310 m gross intersected by Kipper-1), overlying a stratigraphically trapped, non-commercial, thin oil column. The drive mechanism is expected to be depletion drive.

As of 1st January 2021, gross cumulative production was 117.1 Bscf of sales gas, 3.1 MMBbl of condensate and 2.8 MMBbl of NGLs. As of September 2021, the field is producing at a rate of 123 MMscfd of gas, 1,521 bpd of condensate and 4,167 boepd of NGL from 2 wells (Kipper-A2 & Kipper-A4).

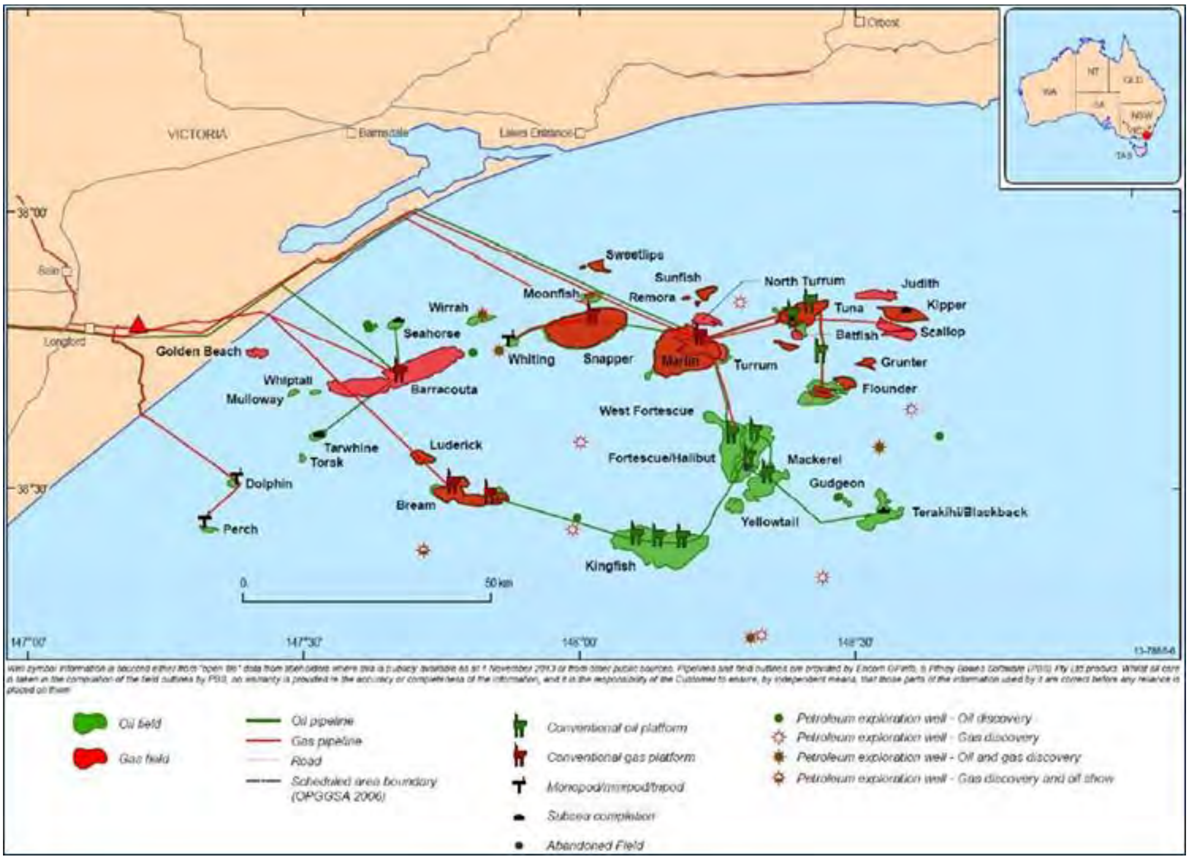
There are two main future development activities associated with Kipper. Phase 1B is associated with an infill well expected to be drilled in the next 5 years, mainly to accelerate production. The second development activity is the installation of compression facilities at West Tuna. The timing of compression is expected to be May 2024. Undeveloped Reserves are attributed to these projects.

GaffneyCline notes that BHP Petroleum's Reserve estimates align very closely with the Operator's own Reserve estimates. GaffneyCline reviewed the technical basis for estimating production profiles and Reserves and notes that the models have considered uncertainties relating to GIIP and reservoir connectivity as well as uncertainty in pressure associated with extrapolating wellhead pressure down to the reservoir datum. Overall, the technical work appears reasonable.

6.1.3 Facilities and Cost Estimates

The Bass Strait assets have been producing oil and gas since 1969. Thirteen oil fields and eleven gas fields have been developed with an integrated production system. Oil and gas production from nearly 300 active development wells is dewatered/dehydrated offshore and transported onshore in multiple gas and oil flowlines and pipelines. An overview of the Bass Strait development is shown in Figure 48. Fields and assets where BHP Petroleum holds no equity have been obscured for clarity.

Figure 48: Bass Strait Offshore Development Layout



Source: BHP Petroleum (modified by GaffneyCline)

All of the fields except Blackback are located in water depths between 40 and 100 m, developed mostly with conventional steel jackets. For some of the smaller tiebacks, mono-tower platforms or subsea tiebacks have been used. Two large, concrete gravity based platforms are installed. Table 45 shows the total wells and facilities inventory, onshore and offshore.

Table 45: Bass Strait Wells and Facilities Inventory

Category	Asset Type	Number
OFFSHORE		
Fields	Oil fields	13
	Gas Fields	7
	Gas Cap	4
Wells	Active wells	~300
	Inactive wells	~300
	E&A wells	~200
Facilities	Steel Jackets	16
	Concrete Gravity Base	2
	Monotowers	2
	Subsea	5
Flowlines & Umbilicals	Flowlines	Multiple
	Umbilicals	Multiple
ONSHORE		
Plants	Gas/oil processing	1
	NGL products	1
Pipelines	Pipelines	16 (922 km)

As noted above, the offshore facilities produce oil and gas to the onshore plants at Longford and Long Island. The Longford plant is a multi-train facility that conditions and compresses gas to sales specification, stabilizes crude, and separates Natural Gas Liquids (NGL) for further processing at the Long Island Point plant.

The Long Island Point plant, located 190 km from Longford, processes NGLs into ethane, propane and butane products for sale; and serves as a crude oil storage terminal for Bass Strait crude prior to domestic or export sales.

Overall facilities integrity is managed within a long-term (10 years) shut-down planning driven by annual planned shutdowns of Gas Plant 2 in the Longford Gas Plant of between 5 and 45 days/annum, generally planned for December. Within this shutdown window, offshore platform shutdowns are planned of 5 to 30 days duration depending on the maintenance and modifications workload required. Using this approach, the Operator has been able to deliver wintertime offshore platform availability (excluding planned shutdowns) of 75.3% up to 100% (averaging 93.4%) over the three year period 2018-2020. During this same period, all platforms were online and available to produce for 63.7% of the wintertime high demand period.

Through the Longford Gas Plant, the Bass Strait fields are connected to the Victoria and Eastern Australia Gas markets. Longford has the facilities to process and deliver gas to the domestic market. Through the Long Island Point facility, oil, condensate, propane, butane and ethane can be processed and delivered to domestic or international markets.

D&R planning and execution is in progress in the Bass Strait development. Currently D&R focus is on the legacy oil fields, which have ceased production, commencing with P&A of platform wells and legacy exploration wells. The Operator's D&R planning extends over the next 20 years, averaging over US$100 MM per year. D&R planning is being managed as an ongoing activity, integrated into the offshore operations planning.

GaffneyCline has reviewed cost forecasts provided by BHP Petroleum covering CAPEX, OPEX and D&R costs for the Bass Strait operations. GaffneyCline's review aligned the cost and production profiles and rebased all costs to a RT2022 basis. Where available, costs were checked against alternative available documentation and against historical cost levels. D&R costs were checked against the Operator's recent delivered costs, current estimates, and recent Australian experience.

Gross CAPEX for further development activities related to the Bass Strait Reserves case is estimated to be US$490 MM and gross CAPEX for development of the Contingent Resources case is estimated to be US$794 MM.

6.1.4 Contingent Resources

BHP Petroleum has a large portfolio of potential projects, but many are associated with small volumes of economically non-viable developments. Contingent Resources are assigned to four projects that are the most mature from a technical and economic viability perspective: North Turrum, Sweetlips, Wirrah and East Pilchard (Table 46).

Table 46: Bass Strait Gross 2C Contingent Resources as at 31st December 2021

Field	Oil and Condensate (MMBbl)	Gas (Bscf)	Development Status
Bass Strait - North Turrum Phase 3	10.3	129.0	Pending
Bass Strait - Sweetlips / Wirrah	22.3	107.2	Pending
Bass Strait - East Pilchard	3.5	40.9	Unclarified
Total	**36.1**	**277.1**	

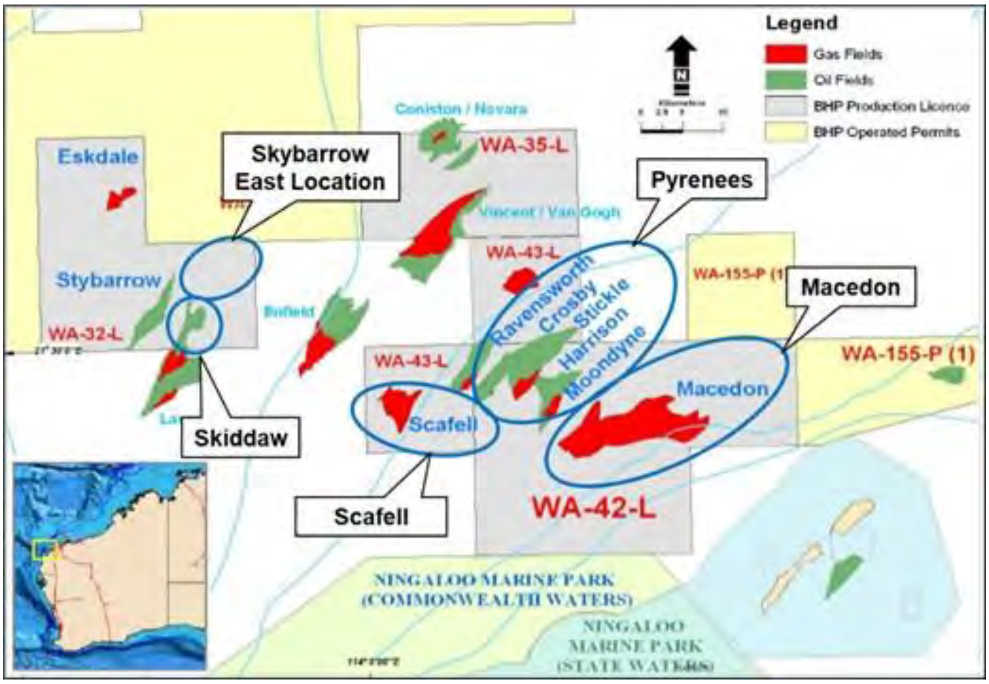
The North Turrum project is associated with Phase 3 development, which is a five well program from the Marlin B platform: three wells in North Turrum targeting acid gas bearing Latrobe L105-400 sands and two wells in Marlin 1-4 targeting acid gas bearing Latrobe L100-L400 sands. The plan is to utilize the recently acquired CGG multi-client seismic data to optimize well placement. The development could be combined with the Turrum sand control project in order to split costs. Planned start-up is in 2024. Sweetlips (10.9 km North of Snapper) and Wirrah (18 km West of Snapper) are satellite fields of the Snapper field. The project has been evaluated by the Operator, but is currently not in the approved plan. The current development concept is to tie back these nearfield gas discoveries to the Snapper platform, similar to what was recently done in West Barracouta. Such a tieback would allow for high deliverability sweet gas to help extend plateau production. The development is technically mature, but economically uncertain. Notional start-up date is late 2025.

East Pilchard is a gas field located south west of the Kipper field. The proposed development concept is a single well subsea development of the Upper 3 sands, tied back to Kipper. The development has some synergy with Kipper Phase 1B drilling (1 infill well). However, compared to North Turrum, Sweetlips and Wirrah, East Pilchard is less mature and has a relatively lower economic viability. There are also technical risks associated with reservoir connectivity uncertainties and thin sands, plus misalignment on the preferred development concept and project timing between BHP Petroleum and the Operator. Notional start-up date is in early 2026.

6.2 Macedon

Macedon is a dry gas field located in Block WA-42-L in the Exmouth Sub-basin, about 40 km north of Exmouth in Western Australia in water depth of 160 to 190 m. It has been developed with four subsea wells and gas is produced to the onshore Macedon gas plant, through a 90 km pipeline. First gas production was in 2013. Figure 49 shows the locations of Macedon and other nearby fields.

Figure 49: Location Map of Macedon, Pyrenees, Skybarrow, Skiddaw and Scafell



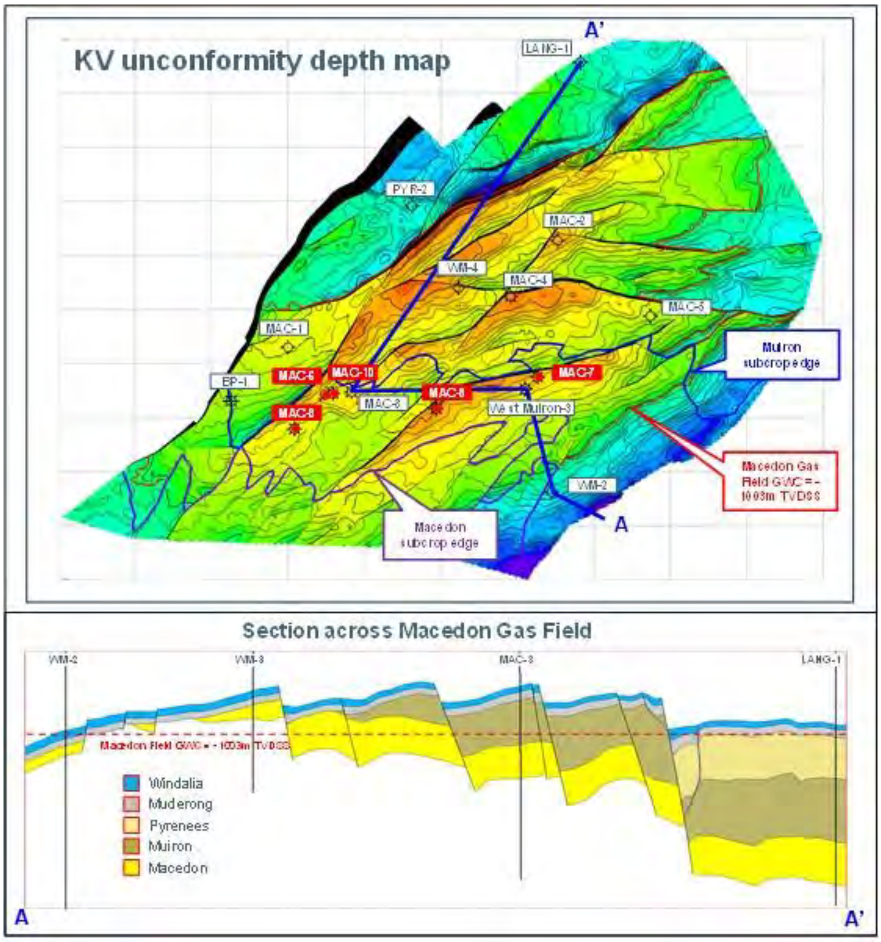
Source: BHP Petroleum

6.2.1 Field Description

Dry gas was discovered in the Macedon sandstone in 1992 by the West Muiron-3 well and the field was appraised by six wells between 1993 and 1994. Four production wells and one producer/injector well were drilled between 2009 and 2010 (the injector/producer Macedon-6 well had injected Pyrenees excess gas into Macedon and now produces Pyrenees fuel gas). The Macedon field is a large structural-stratigraphic feature consisting of several segments – notably three rotated fault blocks that form structural highs at the base of the regional Muderong Shale seal with the sandstone reservoirs sub-cropping the seal, creating a larger stratigraphic closure.

The depth structure map, along with a cross section, is shown in Figure 50. The reservoir is a high quality, stacked, slope turbidite sand, and has average NTG of 72%, porosity of 29% and 2,700 mD permeability. A secondary reservoir is provided by the Muiron member, which is a product of transgressive inner shelf or slope fan complex, and has average NTG of 35%, porosity of 23% and 60 mD permeability.

Figure 50: Macedon Depth Structure Map and Cross Section



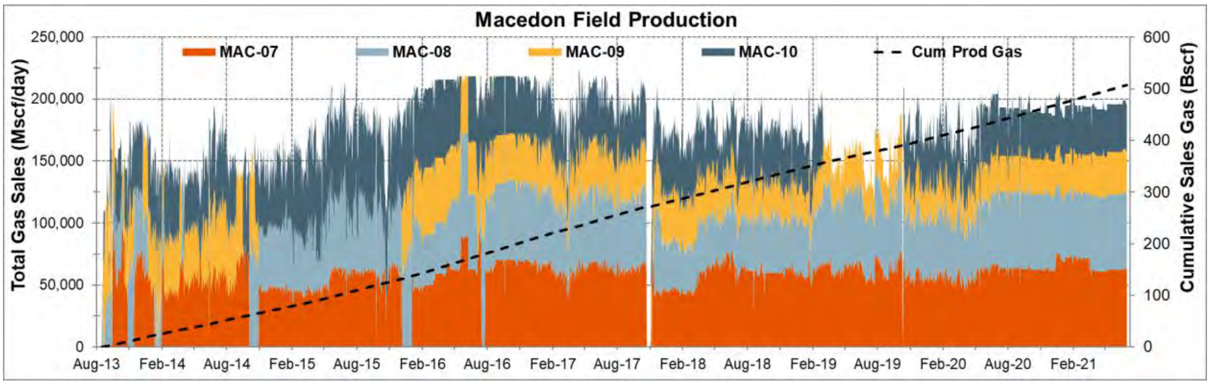
Source: BHP Petroleum

6.2.2 Field Development and Production Profiles

The Macedon development comprises four subsea wells (Macedon-7, 8, 9, and 10) located in the Central and Southern Field Segments, providing drainage to all segments of the reservoir. The Northern segment does not contain a well due to its low volumes and proximity to water. However, fault-seal studies suggest that this segment is not structurally isolated and can be drained by the development wells in the Central segment.

Peak production of some 220 MMscfd was achieved in 2016, with current production just below 200 MMscfd (Figure 51). The total raw gas and condensate production until 30th June 2021 are 518 Bscf (507 Bscf sales gas) and 33.6 MBbl, respectively. Total fuel and flare consumption is 10.3 Bscf. Macedon fuel burn rate is approximately 3.6 MMscfd based on historical trends.

Figure 51: Macedon Historical Production



Source: BHP Petroleum

Due to friability of the reservoir, sand control was required and open-hole gravel pack completions were installed in development wells. The completions provide a maximum allowable rate of 100 MMscfd per well.

GaffneyCline has reviewed the material balance (P/Z plot) provided by BHP Petroleum, including plots illustrating the history match of gas rate, bottom-hole and tubing-head pressures until mid-March 2021 and forecasts from numerical models. Overall, the technical work appears reasonable, and GaffneyCline has accepted the Low and Best estimate production forecasts prepared by BHP Petroleum for the purposes of estimating Reserves. The gross volumes are presented in Table 47 and production profiles are shown in Figure 52.

Currently, end of field life is determined by the minimum flowrate of 50 MMscfd, or the minimum arrival pressure at the Macedon plant (26 barg). A wet gas compression project is under consideration at the plant that would reduce the minimum arrival pressure to 15 bara. Additional fuel gas is supplied to the Pyrenees FPSO via the Macedon 6 well. Excess Pyrenees gas was injected into the Macedon reservoir for storage and to be recovered in the future.

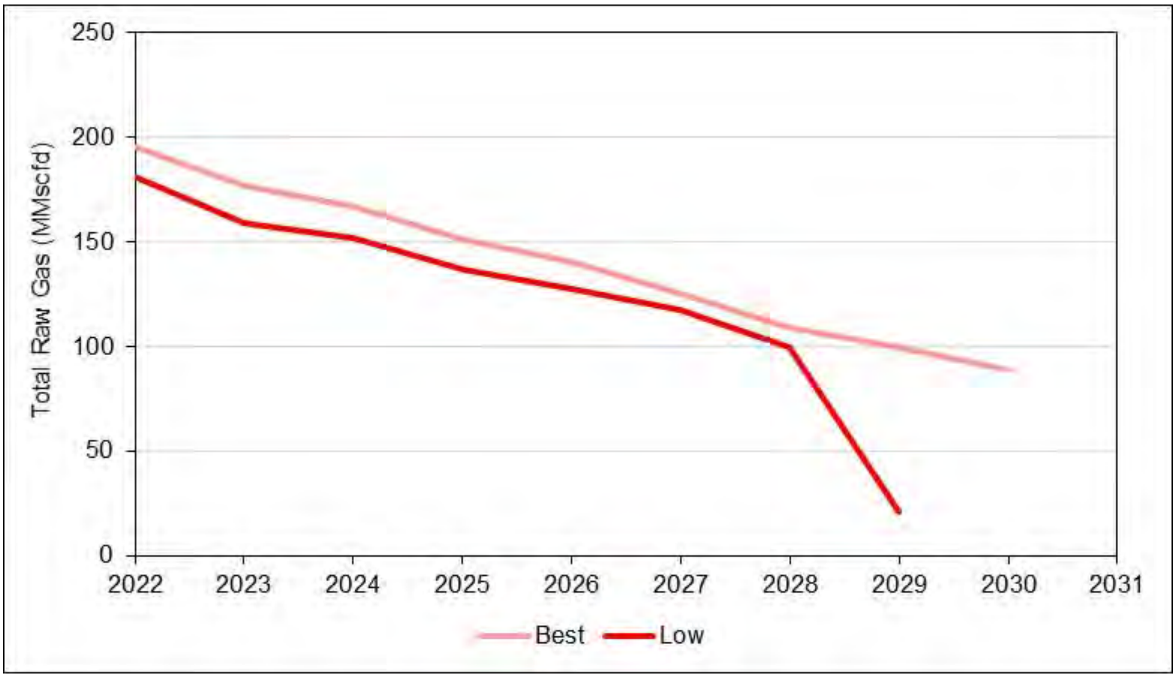
Table 47: Macedon Estimates of Gross Remaining Recoverable Gas as at 31st December 2021

Item	Remaining Recoverable Gas (Bscf)	
	Low Estimate	Best Estimate
Macedon Sales Gas	339	412
Macedon Fuel Gas	10	12
Pyrenees Fuel Gas from Macedon	14	34
Total	**363**	**457**

Note:

1. Pyrenees fuel from Macedon is not available for sale but is reported herein for completeness.

Figure 52: Macedon Gas Production Profiles



Source: GaffneyCline from BHP Petroleum Data

6.2.3 Facilities and Cost Estimates

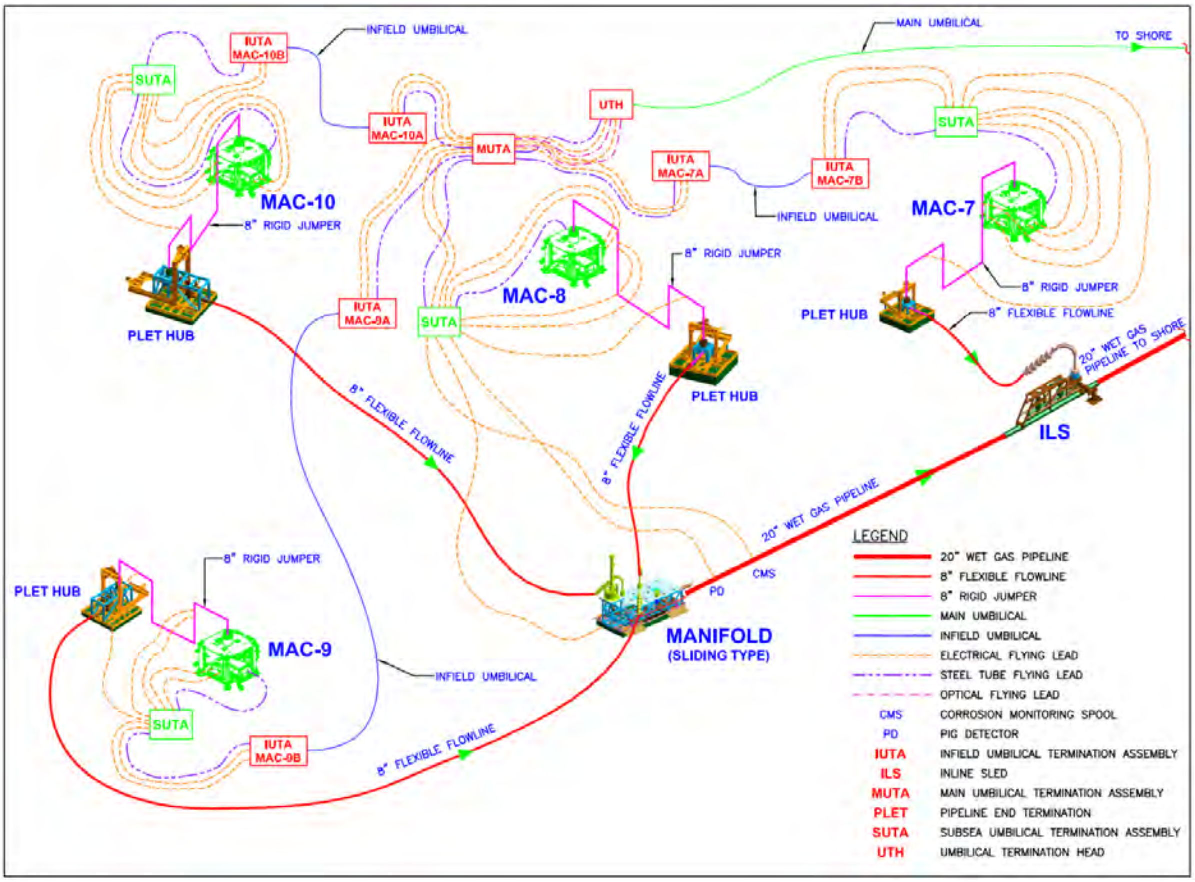
The Macedon plant is designed to process a maximum of 220 MMscfd of gas and delivers to the Western Australia domestic gas market via the Dampier to Bunbury Natural Gas Pipeline (DBNGP). The development is designed to be a reliable supplier of gas with production availability above 95%. The Macedon offshore configuration is shown in Figure 53.

Macedon has been in production since August 2013 with only one full shutdown in late 2017. Despite occasional problems with communications and controls with some of the subsea wells, overall system availability has exceeded 98%.

Macedon D&R activities are planned to commence two years prior to end of field life and be carried out over a 9-year period. This is realistic, typical of current industry D&R planning, and accepted by GaffneyCline.

GaffneyCline has reviewed cost forecasts provided by BHP Petroleum covering CAPEX, OPEX and D&R costs for the Macedon operations. Where available, costs were checked against alternative available documentation and against historical cost levels. D&R costs were checked against current estimates, and recent Australian experience.

Figure 53: Macedon Offshore Development Layout



Source: BHP Petroleum

6.2.4 Contingent Resources

BHP Petroleum's estimates of gross Contingent Resources are shown in Table 48. GaffneyCline has reviewed BHP Petroleum's analyses, including BHP Petroleum's dynamic simulation models, and has accepted BHP Petroleum's gross Contingent Resources. The Macedon Front End Compression project is the most mature, classified under PRMS as Development Pending. The two infill wells are relatively immature and are classified as Development Unclarified while the Black Pearl tie-back project is Not Viable.

Table 48: Macedon Gross 2C Contingent Resources as at 31st December 2021

Project	Development Status	Gas (Bscf)
Macedon Front End Compression	Pending	57
Muiron Infill Well	Unclarified	53
Macedon Infill Well	Unclarified	29
Black Pearl Tie-back	Not Viable	10
Total		**150**

6.3 Pyrenees

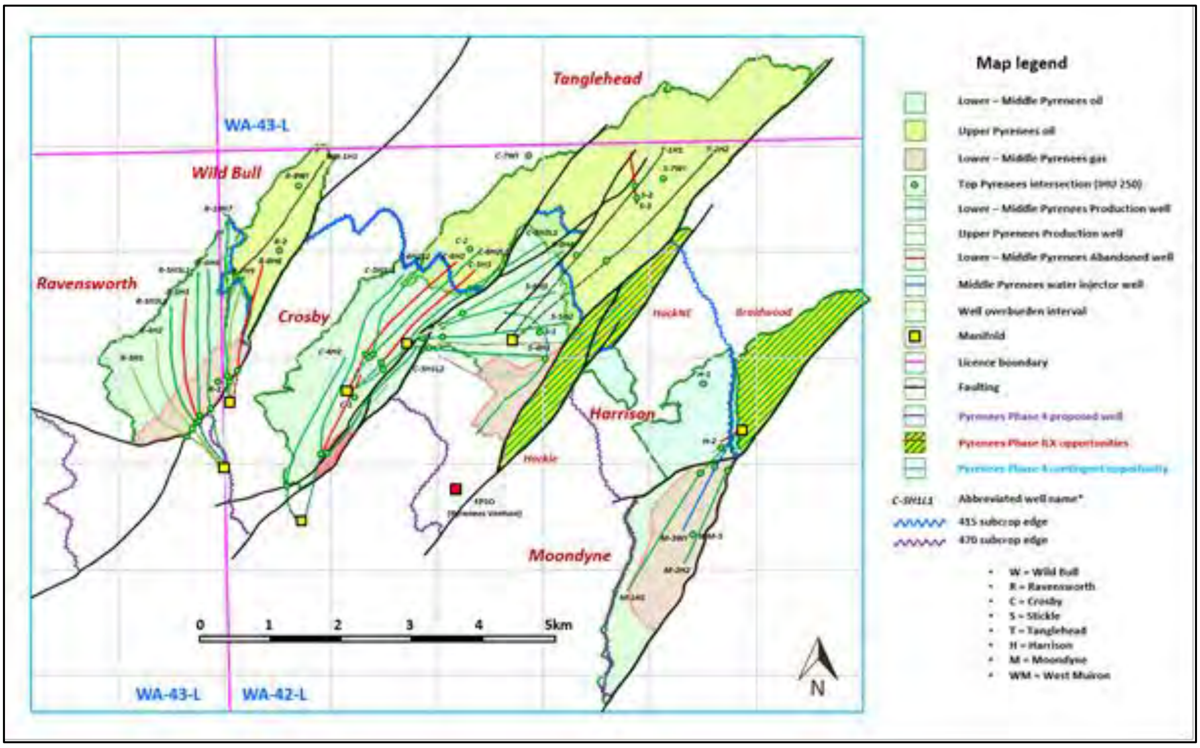
The Pyrenees oil development comprises a group of fields (Figure 49) located in 200 m water depth in the Exmouth Sub-basin, 40 km NW of Exmouth in Western Australia in Blocks WA-42-L (BHP Petroleum interest 71.43%) and WA-43-L (BHP Petroleum interest 39.999%). Production commenced in 2010 and the oil is processed on the Pyrenees Venture FPSO.

6.3.1 Field Description

The asset comprises several oil accumulations trapped in a series of stair-stepping, northeast-southwest trending, fault blocks, and in dipping reservoirs truncated by an unconformity. The main fault blocks are Ravensworth, Crosby, Stickle, and Harrison, but further stratigraphic separations divide the field into seven pools (Figure 54). Oil was first encountered in the field in 1993 by West Muiron-5 well, which penetrated the Middle Pyrenees Moondyne pool. In 2003, Ravensworth-1 and Crosby-1 found oil in the respective fault blocks, followed by Stickle-1 and Harrison-1 in 2004.

The Pyrenees reservoirs are the Early Cretaceous sands of the Barrow Group found at around 1,200 mss. The reservoirs have high quality, with NTG of over 90%, average porosity 28% and average permeability 4,500 mD. The sandstones are the products of a progradational, wave-dominated, shelf margin delta, with extensive shoreface deposits. The reservoirs are divided into three groups: Lower, Middle, and Upper Pyrenees. The oil is biodegraded with 19 deg API gravity.

Figure 54: Pyrenees Oil Pools and Well Locations



Source: BHP Petroleum

6.3.2 Field Development and Production Profiles

The initial development consisted of the subsea development of Ravensworth, Crosby and Stickle oil and gas fields. Development drilling started in January 2009 and production commenced in 2010. The first infill well, STI-8H4, came online in July 2012.

Phase 2 of the development was completed during 2014, which included the development of the Upper Pyrenees (Tanglehead and Wild Bull), with first oil in January 2014, and Moondyne fields, with first oil in April 2014.

The Phase 3 drilling campaign was executed during 2015 and 2016 and consisted of two new wells (STI-9H5 and RAV-10H7), one single lateral re-entry of an existing well (CRO-5H3) and three dual lateral re-entries of existing wells (RAV-5H3, CRO-6H4, and CRO-3H1).

The Pyrenees development comprises the following components:

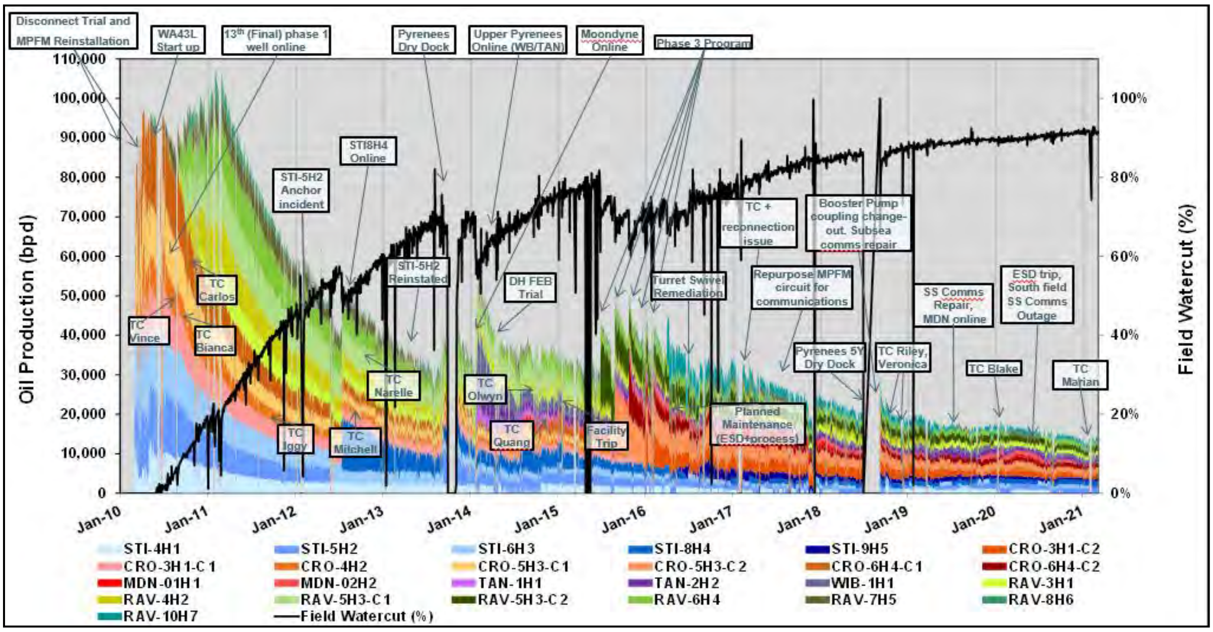
- Twenty-six subsea wells, made up of the following:
    - 21 production wells (seven in Ravensworth, four in Crosby, five in Stickle, one in Wild Bull, two in Tanglehead, and two in Moondyne).
    - Three vertical produced water disposal wells (one each in Ravensworth (failed), Crosby, and Stickle fields).

  - o One horizontal water disposal well that provides pressure support to the Moondyne field.
  - o One gas injection/production well (Macedon 6) in the nearby Macedon gas field.
- Flowlines from the subsea wells to subsea manifolds, and flowlines from subsea manifolds to an FPSO.

Historical production performance on a well-by-well basis is shown in Figure 55. To date, approximately 152 MMBbl of oil has been produced at Pyrenees.

A number of characteristics affect oil recovery from the Pyrenees fields including moderately viscous oil (8 to 11 cP), thin oil columns (0 to 37 m), high permeability and high NTG sands, and large active aquifer beneath most of the oil column. These attributes typically lend themselves to high field recoveries, a significant portion of which can be contained in characteristic long production “tails”. Estimates of recoverable volumes have been made by production analysis that are consistent with simulation-based estimates.

Figure 55: Pyrenees Production History



Source: BHP Petroleum

BHP Petroleum uses an Integrated Production Model (in the GAP software) to optimise forecasts within facility constraints. The GAP model is used by BHP Petroleum for both short and long-term forecasting. The producing wells and fields are constrained by a combination of network and facility limitations, specifically the network backpressure and facility water processing. Due to the fluid handling constraints, several wells are cycled while other wells require additional gas lift for flowline stability at the expense of other wells. It is expected these trends will continue in the future. Based on historical performance, well productivity and reservoir pressure tend to remain relatively constant over time. The Low and Base case forecast assumptions are shown in Table 49.

Table 49: Pyrenees Field Life Assumption

Item	Low Estimate	Best Estimate
Well Water Cut (WCT)	96%	Not imposed Typical 98%
End of Facility Life	FY2035	FY2035

GaffneyCline carried out a review of estimates of remaining recoverable volumes by analysing historical performance, using DCA for the main fields. Low and Best estimate forecasts were generated for the period from 1st July 2021 to 31st January 2028 (BHP Petroleum low estimate economic limit) and to 30th June 2036 (end of facility life for best estimate). GaffneyCline's remaining oil volume estimates are presented in Table 50.

Pyrenees fuel gas consumption averaged around 10 MMscfd until mid-2020. Since then, fuel and flare usage has reduced to approximately 8.5 MMscfd due to compressor restaging. These reductions have been included in the fuel forecast. As Pyrenees gas caps have been blown down and oil rate reduces, the remaining produced gas volume is no longer enough to power the facility. Gas produced from the Macedon field via Macedon-6 is used to make-up the difference required.

Table 50: GaffneyCline Estimated Gross Technical Remaining Oil Volumes by Field as at 31st December 2021

Field	Development Status	Produced Oil (MMBbl)	Remaining Recoverable Oil (MMBbl)	
			Low Estimate	Best Estimate
Crosby	Producing	43.8	5.0	9.3
Moondyne	Producing	2.7	0.9	1.2
Ravensworth	Producing	42.3	4.8	8.9
Stickle	Producing	39.5	6.0	9.8
Tanglehead	Producing	5.0	1.0	1.8
Wild Bull	Producing	3.1	0.3	0.7
Total		**136.4**	**18.0**	**31.7**

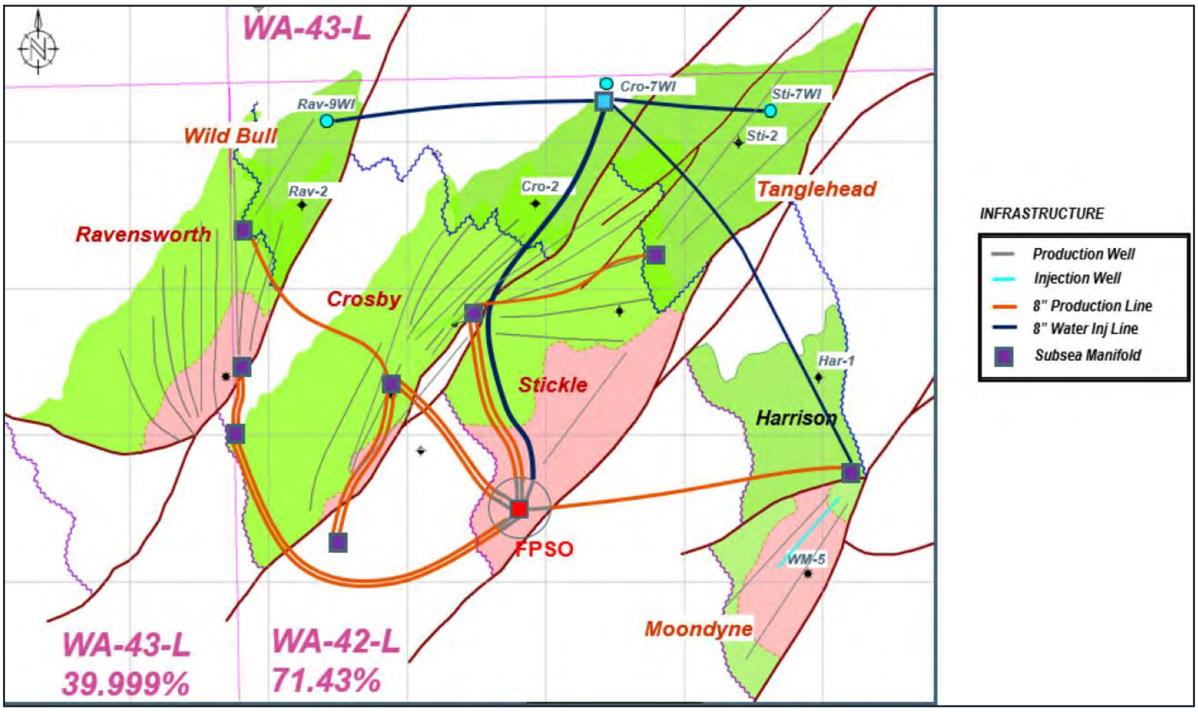
According to the WA-43-L tie-in agreement, all gas produced into the Pyrenees production network becomes the property of the WA-42-L joint venture. This affords BHP Petroleum rights to 71.43% of the total fuel gas. Fuel gas volumes incorporate the results of Phase 2 and Phase 3 drilling campaign.

6.3.3 Facilities and Cost Estimates

The Ravensworth, Wild Bull, Crosby, Tanglehead, Stickle, Harrison, and Moondyne Fields are developed with subsea wells tied back to the Pyrenees Venture FPSO (Figure 56). Oil is exported to the buyer's vessel from the Pyrenees Venture FPSO. Gas is used as fuel or reinjected into the Macedon field.

Since first oil in 2010, the FPSO has been regularly dry docked in 2014 and 2019, with the next scheduled dry docking expected in 2024, assuming a 5-year scheduled interval. Field production is constrained by the FPSO water handling limit, currently approximately 148 Mbwpd.

Figure 56: Pyrenees Venture Development Layout



Source: BHP Petroleum

The subsea system has experienced problems with communications failures. At an overall system level, the Operator tracks "deferment", that is, the oil production delayed because of unplanned facilities outages. Over the last three and a half years, deferment has averaged 937 bopd, or some 5.5%. This is consistent with the Operator's planned uptime for production forecasting. The primary cause of deferment is recorded as "weather", i.e. precautionary cyclone shutdowns.

Pyrenees D&R activities are planned to commence two years prior to end of field life and be carried out over a 9-year period. This is realistic, typical of current industry D&R planning, and accepted by GaffneyCline.

GaffneyCline has reviewed cost forecasts provided by BHP Petroleum covering CAPEX, OPEX and D&R costs for the Pyrenees operations. The Operator's D&R costs were adjusted in line with GaffneyCline's experience of current Australian D&R costs.

6.3.4 Contingent Resources

The 2C Contingent Resources are presented in Table 51. These projects are part of Phase 4 and have passed Gate 3 (Project Sanction) of BHP Petroleum's future opportunities timeline. They are currently classified as Contingent Resources Development Pending, although their migration to Reserves is imminent (subject to favourable economic evaluation). The remaining 2C Contingent Resources volumes are shown in Table 52. These are part of Pyrenees Phase 5 development plan, and are not included in BHP Petroleum's five-year plan. They are at various stages of maturity as shown in Table 52, but as a group have been classified Development Unclarified.

Table 51: GaffneyCline Gross 2C Contingent Resource for Pyrenees Phase 4 as at 31st December 2021

Field	Development Status	Oil (MMBbl)	Remarks
Crosby	Pending	2.7	Water Shutoff
Stickle	Pending	1.8	STI-4H1DL
Total		**4.5**	

Table 52: GaffneyCline Gross Contingent Resource for Pyrenees Phase 5 as at 31st December 2021

Field	Development Status	Oil (MMBbl)	Remarks
Crosby	Unclarified	3.0	CRO-4H2 DL
Moondyne	Not Viable	4.0	Infill Drilling
Ravensworth	On-Hold and Not Viable	3.3	RAV-8H6
Stickle	Unclarified	1.4	STI-6H1
Tanglehead	Unclarified	1.6	TAN-2H2 DL
Wild Bull	On-Hold	1.9	Wild Bull-2H2 SL
Harrison	On-Hold	3.5	HAR-3H1 TL
Total		**18.5**	

6.4 Scafell

The offshore Scafell gas field is located in the NW Shelf of Australia, approximately 120 km west of Onslow and 40 km north of Exmouth within the existing Pyrenees field production licence WA-43-L (Figure 49). BHP Petroleum is the operator of WA-43-L with a 39.999% interest; Santos holds a 31.501% interest and Inpex a 28.500% interest. The permit forming the production lease was originally granted in September 2009. The Scafell gas field will be developed and produced under the existing production licence WA-43L. Under the provisions of the Offshore Petroleum Act 2006, the duration of the licence is indefinite up until no petroleum recovery operations have been carried for 5 years.

6.4.1 Discussion

Scafell is a complex structural/stratigraphic trap approximately 3 km by 4 km in size and reservoir depth of ~1,300 to 1,500 mss in water depth of 282 m. The reservoir has excellent properties, with porosity of 25% and permeability between 300 and

1,800 mD encountered at the Scafell-1 location. Gas properties are expected to be similar to the adjacent Macedon gas field (lean and dry). Development of Scafell is planned to be a tie-back to the Macedon manifold and timing will depend on when the Macedon gas production comes off plateau or when there is an increase in WA domestic gas demand.

For Scafell BHP Petroleum has 2C gross Contingent Resources of 94.5 Bscf (sales gas plus fuel gas for Pyrenees oil field), classified as Development Not Viable. The development project has not been sanctioned and no recent progress has been made. The unitised development plan has not been finalized, and no gas contract has been signed.

6.5 Other Australian Assets

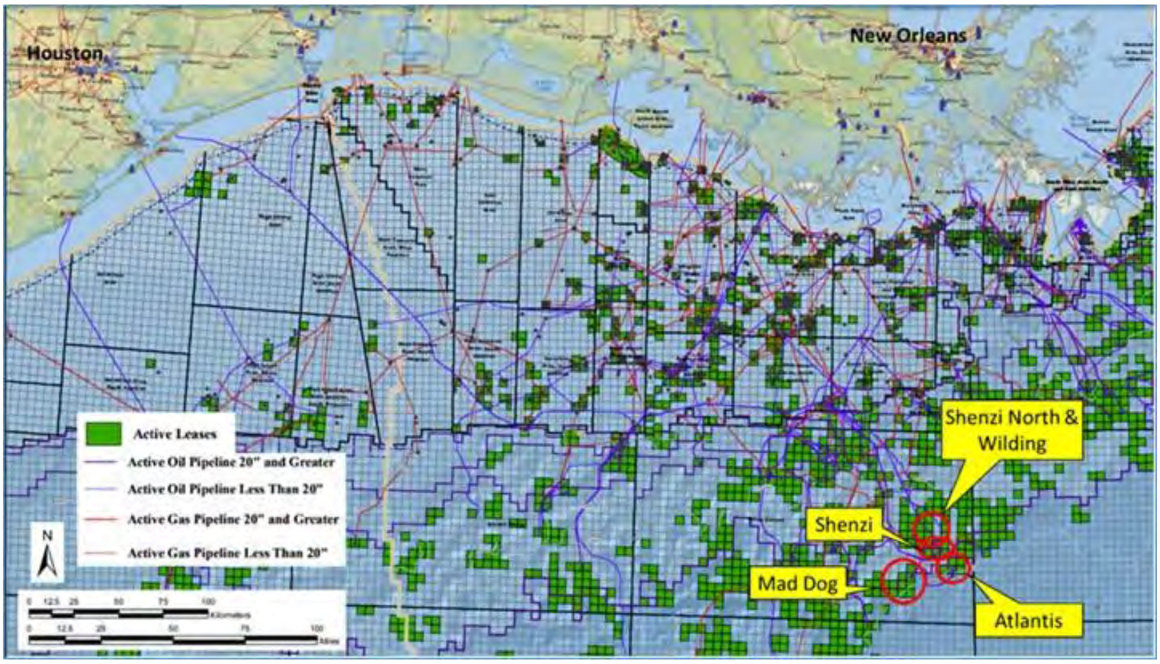
In addition to discovered and producing assets described in preceding sections, BHP Petroleum also has outstanding D&R obligations in respect of three fields, Minerva, Griffin, and Stybarrow that have ceased production, where decommissioning and restoration activities are in planning or in progress.

7 BHP Petroleum United States Gulf of Mexico

BHP Petroleum has interests in four developments in close proximity in the US GOM: Shenzi, Shenzi North and Wildling, Atlantis and Mad Dog (Figure 57).

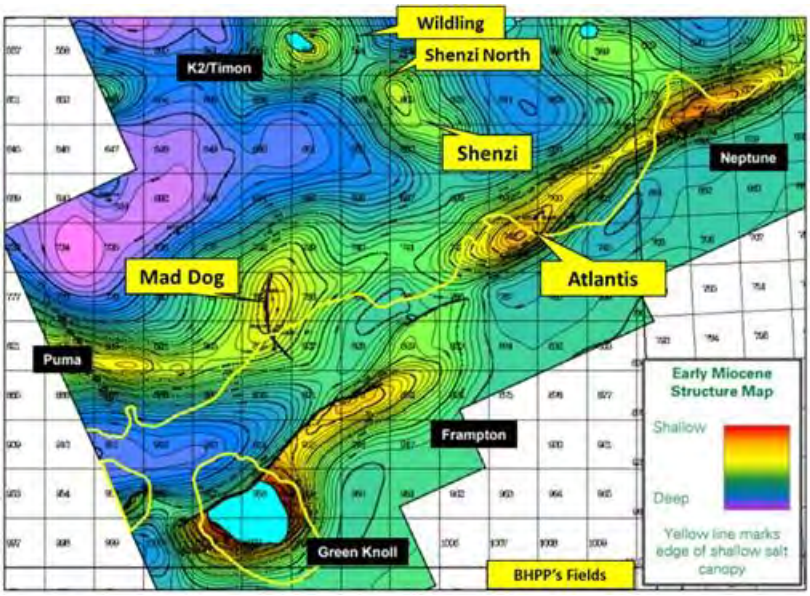
A depth structure map (Early Miocene) shows the relationship of the major structural highs and oil fields (Figure 58). The dominant features are a series of SW-NE trending, elongated, high-relief structures from Green Knoll in the south, through Frampton, Atlantis and Neptune in the NE. They are primarily compressional salt-cored anticlines that trend roughly parallel to the leading edge of the shallower, overthrust (allochthonous) salt body (yellow line on map). Landward of these high-relief structures are more subtle, four-way structural closures formed primarily as drape over remnant salt-cored areas; Puma-Mad Dog in the SW and Shenzi and K2 to the north.

Figure 57: Location Map of BHP Petroleum's Assets in US GOM



Source: Modified from BOEM (US Bureau of Ocean Energy Management (Visual-1-Active- Leases-and-Infrastructure_2.pdf as of May05, 2021)).

Figure 58: Early Miocene Structure Map



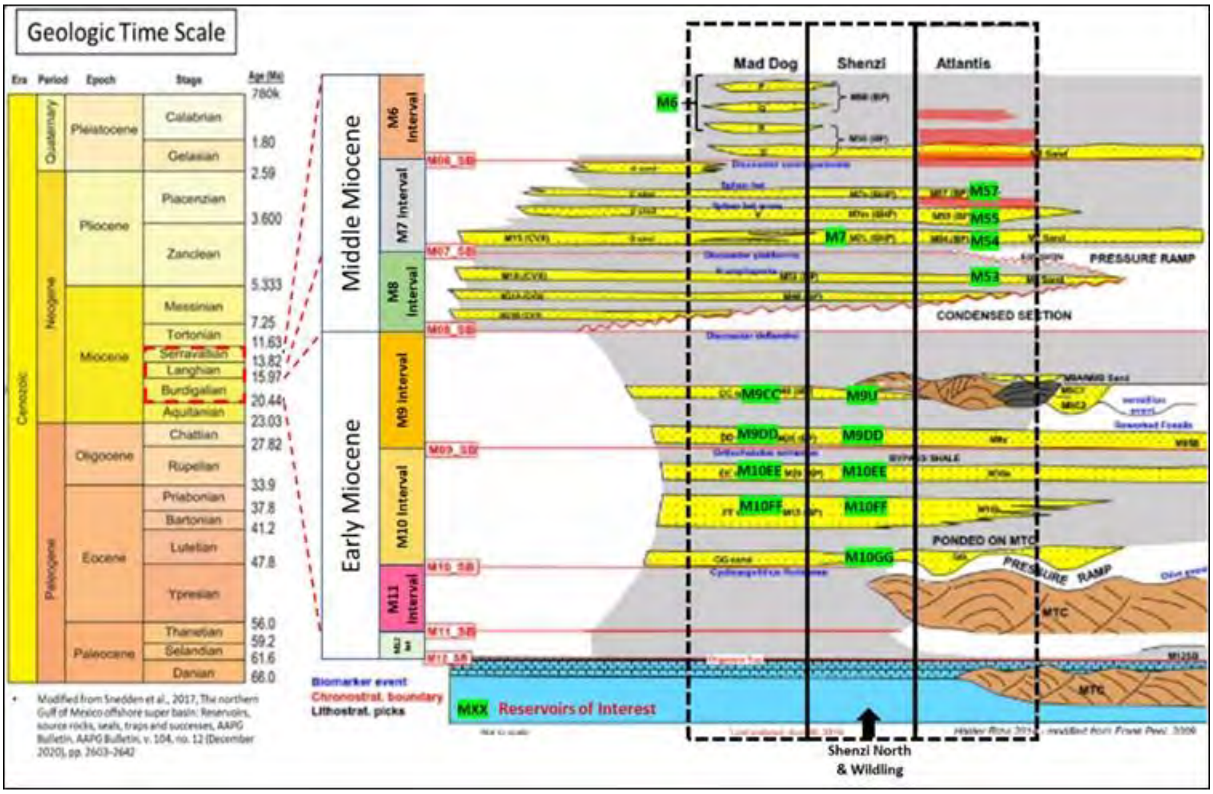
Source: Modified After: Walker, C. D., and G. A. Anderson, 2016, Simple and efficient representation of faults and fault transmissibility in a reservoir simulator: Case study from the Mad Dog Field, Gulf of Mexico: Gulf Coast Association of Geological Societies Transactions, v. 66, p. 1109–1116. http://www.gcags.org/exploreanddiscover/2016/00177_walker_and_anderson.pdf. 2016.

Seismic interpretation, supported by drilling, has demonstrated that underlying salt was actively moving upward, and at times laterally, during the deposition of the overlying sediments. This movement most importantly affected the Miocene sands. During and after the large-scale salt movement, extensional fault movement, contemporaneous with sediment deposition, caused significant, localized sand thickness. These crestal extensional faults, and the accompanying sediment thickness variations, cause compartmentalization seen in all the fields.

The BHP Petroleum fields are either north of, or straddle, the southern limit of allochthonous salt (yellow line in Figure 58), therefore either the whole or a significant portion of these fields are sub-salt. The presence of the shallow salt generates problems with seismic imaging, requiring latest seismic acquisition and processing technologies to ensure optimum fault and reservoir definitions.

A generalized stratigraphic column showing the nomenclature for the BHP Petroleum fields is shown in Figure 59 (Shenzi North and Wildling are similar to Shenzi). The primary reservoirs at Mad Dog, Shenzi, Shenzi North and Wildling are Early Miocene M9 and M10 deep-water turbidite fans. These sands are also present at Atlantis but are more shale-prone and are not development targets. At Atlantis, the primary reservoirs are the thick, blocky Middle Miocene M55 and M54 turbidite basin floor sheet fans. The age equivalent sand, the M7, is more channelized in Shenzi, Shenzi North and Wildling where it is a secondary reservoir target. The secondary reservoirs are Middle Miocene M57 and M53 intervals in Atlantis and the M6 in Mad Dog.

Figure 59: Geologic Time Scale, Stratigraphic Nomenclature of BHP Petroleum's GOM Fields



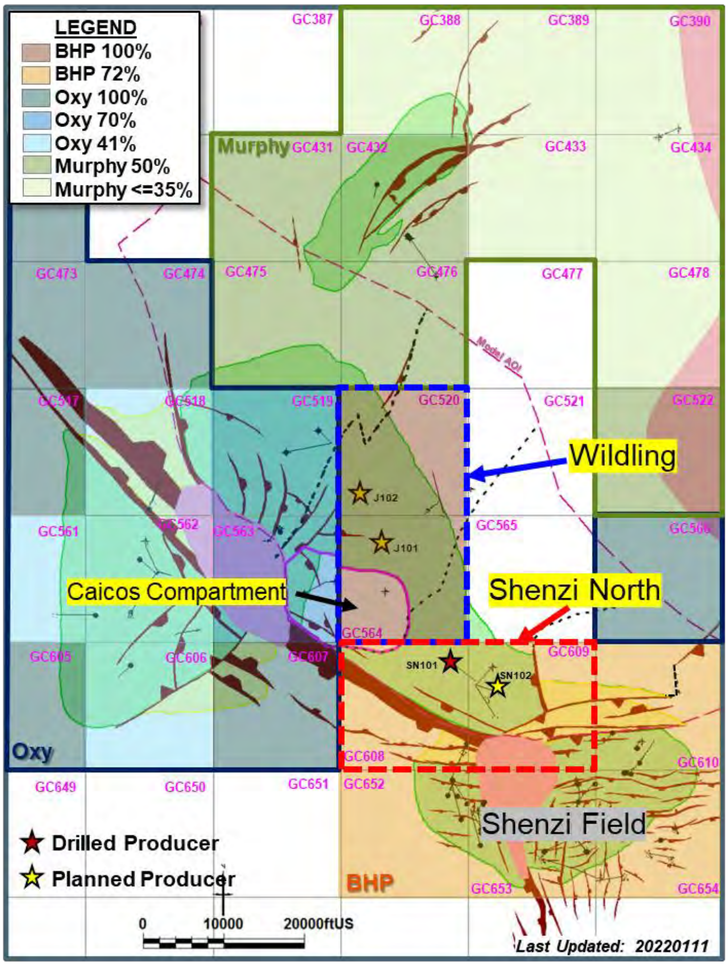
Source: GaffneyCline Modified from BHP Petroleum

BHP Petroleum has undertaken seismic interpretation, petrophysical analysis, static geological modelling, decline curve analysis and reservoir simulation for these fields, which were made available to GaffneyCline for review.

7.1 Shenzi

The Shenzi Field was discovered in 2002 in the Green Canyon area of the Gulf of Mexico in approximately 1,340 m water depth. It lies mainly in the 4-block area comprised of OCS blocks GC-610, 652, 653 and 654, and also partly extends into GC 608 and 609 (Figure 60). The reservoir depths are approx. 6,700 to 8,530 mss. The field is operated by BHP Petroleum with 72% WI and Repsol holds the remaining 28% WI.

Figure 60: Lease Ownership Status for Shenzi, Shenzi North and Wildling

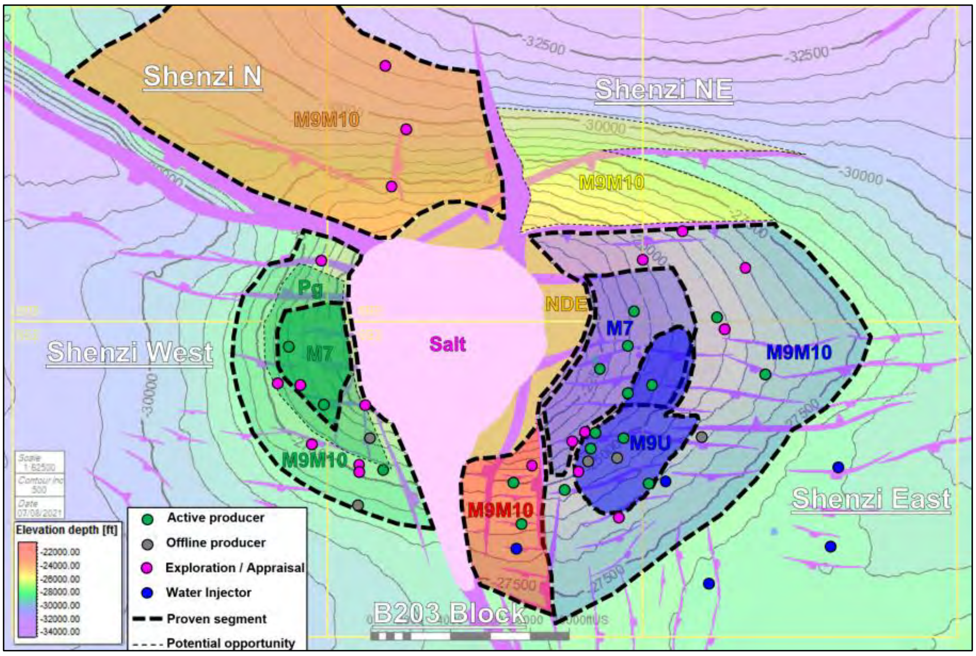


Source: BHP Petroleum

7.1.1 Field Background

The Shenzi structure is a large, salt-cored, four-way dip closure with a series of extensional faults that radiate out from the salt core shown in pink (Figure 61). Faults and salt-welds are shown in purple.

Figure 61: Shenzi Field Structure



Source: BHP Petroleum

Seismic and well information shows the Shenzi field to be compartmentalized according to geological structure (sealing faults, salt-welds, etc.) and stratigraphy. The two largest structural compartments are found on the west (Shenzi West) and east (Shenzi East). They are separated by the salt stock and welds, each with its own oil-water contact for the primary M9/M10 reservoirs.

In the south-east, well results show a smaller structural compartment, B203. The boundaries for this block (B203 Block) are defined to the west by a large seismically defined salt feeder/weld and structural normal fault, down thrown to the west that separates the segment from West Shenzi. It is compartmentalized to the east by structural normal faults that are mapped partially with seismic, as well as faults and missing section identified in wells and to the north by sand pinch out. The lack of pressure communication to the east is supported by pre-production pressure measurements, production history and well-based pressure gauge responses.

Outside of the Shenzi field are two additional structural compartments; Shenzi North (located northwest of the field) and the undrilled North-eastern compartment (Shenzi NE). The Shenzi North compartment has been drilled and is included in the Greater Wildling development project (Section 7.2).

In addition to the structural subdivisions, there are three stratigraphic producing intervals, one on the west side and three on the east side including the younger M9U and M7 reservoirs.

The M9U reservoir is an Early Miocene sand within the upper M9 sequence deposited as local channelized turbidite fan lobes that are highly deformed by mass transport processes. Based on well data, the M9U interval is of variable thickness and laterally discontinuous. Seismic data provide resolvable M9U reservoir edges on the western and northern parts of the structure. Over the rest of the structure, reservoir extent is determined by well control and a depositional environment model.

The M7 reservoir is a laterally extensive Middle Miocene amalgamated and channelized sheet sand complex. Well data indicate that the M7 sand thins toward the north onto what is interpreted to be a paleo-ridge. Additionally, seismic data indicate the interval thins from the east flank toward the current structural high associated with the salt diapir.

The Shenzi field is entirely covered by an allochthonous salt sheet resulting in a challenging seismic imaging environment. The original 3D seismic was acquired in 2002, followed by an additional acquisition in 2006 that was reprocessed in 2009 and 2014, resulting in improved interpretation that showed significant uplift in many areas, better salt definition, illumination of the east flank, and the interpretation of E-W trending reverse faults in the east flank.

In 2019, an ocean bottom node (OBN) seismic survey was acquired leading to the interpretation of new faulting regimes and building of new reservoir models. The resolution of the new OBN seismic dataset is an improvement over the previous data. Small throw faults are still difficult to identify. While the seismic resolution is improved, however, it is greater than the sand thickness (~30 m). Therefore, seismic interpretation needs to rely on mapping packages of reflections and not a single trough or peak that ties to a single sand. Assessment of lateral stratigraphic changes in the thickness of the sand bodies and delineation of slump features remain uncertain. Despite the relatively low resolution of the seismic data, the overall data quality is very good for sub-salt seismic. Overall, the resulting structure maps from seismic interpretation, tied back reasonably well to the available well data.

Well data comprising modern well logs, cores, formation pressure and fluid sample PVT data exist in the field. GaffneyCline reviewed available reservoir and fluid data. The reservoir units are predominantly clean sandstones at depths of about 6,650 to 8,670 mss, with average porosity range of 20% to 23%. The average permeability ranges from 20 to 500 mD. Shenzi is a highly under-saturated oil field with reservoirs pressure ranging from ~12,000 to ~14,900 psia and saturation pressure ~1,500 to 2,300 psia. Oil gravity is 30 to 34 °API, GOR is 250 to 550 scf/stb and viscosity is 1.1 to 1.2 cP.

7.1.2 Field Development

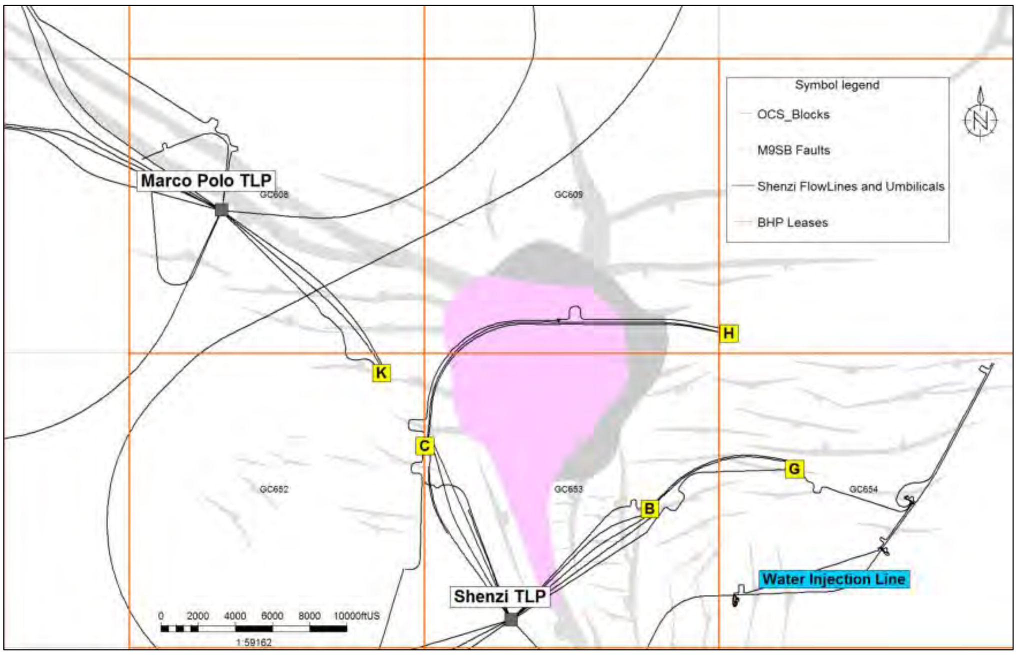
As of 31st October 2021, about 43 wells and side-tracks (excluding wells in the Shenzi North block), have been drilled in the Shenzi field, of which 20 wells are producers and five are water injectors (Figure 61). Eighteen of the 20 development wells are tied back to the Shenzi Tension Leg Platform (TLP) via manifolds B, G, C and H, with the remaining two tied back to the Marco Polo TLP via manifold K (Figure 62).

Production started in 2007 from wells in the South West fault block, producing to the Marco Polo production facility. Production from the other fault blocks to the Shenzi Tension Leg Platform (TLP) commenced in 2009.

The Shenzi TLP has a nameplate capacity of 100 Mbopd oil production and 125 Mbwpd water injection capacity. Gas lift capabilities are present and enabled at the B and the C manifolds. Sales oil and gas is exported through a third party operated Poseidon and CHOPS export pipeline system.

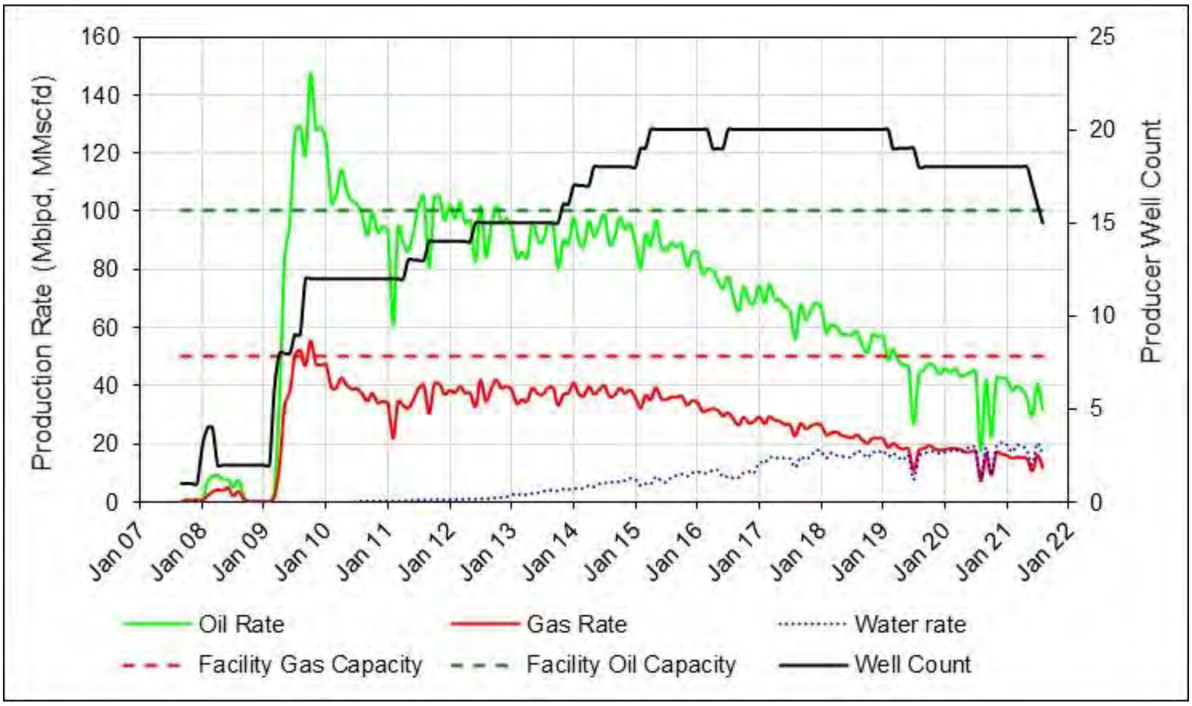
The production peaked above 100 Mbopd in 2009 but has since declined to around 42 Mbopd as of May 2021 (Figure 63). A water injection program was implemented with injection starting in May 2012. In addition, subsea multiphase pumping (SSMPP) capabilities is being implemented for the Shenzi TLP and expected to be operational in late 2022.

Figure 62: Shenzi Facility Overview



Source: BHP Petroleum

Figure 63: Shenzi Field Historical Production



Source: BHP Petroleum

Note:

1. Facility capacity of Shenzi TLP reflected on the plot, while production is both to the Shenzi and Marco Polo TLPs

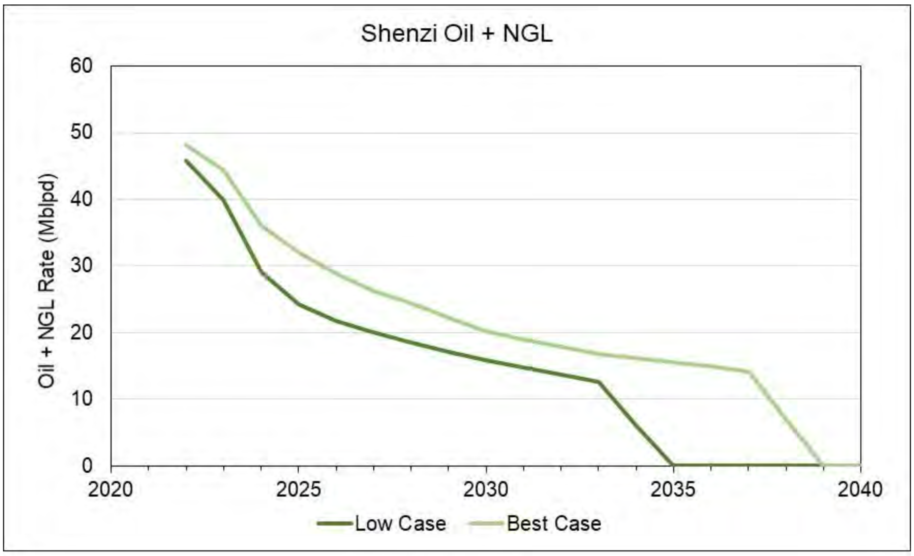
The M9/M10 sands are produced in a commingled fashion from all five zones; DD, EE12, EE, FF, and GG. The M9U and M7 reservoirs were developed as single zone frac-pack completions from stand-alone wells and have not been commingled with the M9/M10 reservoirs. The primary drive mechanism providing pressure support to production wells is aquifer influx. The East (M9/M10), and East (M9U) reservoirs have been developed with water injection for additional pressure support. The injectors have been drilled, completed and brought on stream after production had commenced. At the time of drilling, pressure depletion was observed in all the injection wells confirming connectivity to the oil producers.

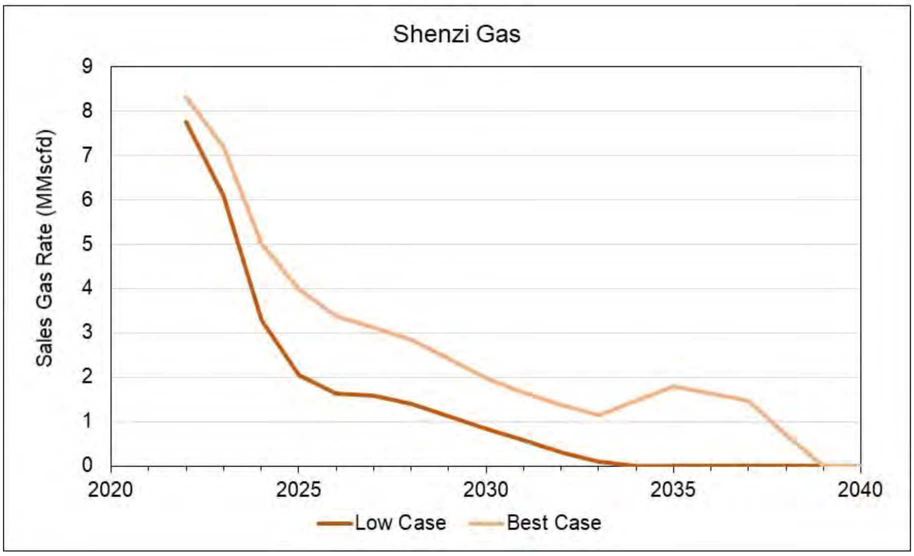
GaffneyCline reviewed the STOIIP, production forecasts and estimated recoverable volumes for the target compartments in the field from the static geological and simulation models (DCA only for the B203 block) provided by BHP Petroleum. In particular, GaffneyCline review the history match of the simulation models and where possible performed decline curve analysis of existing wells with long term production history to validate the simulation results. Overall, GaffneyCline found the production forecasts from the simulation models to be reasonable.

7.1.3 Resources Estimates

Reserves in the Shenzi field are attributed to current producing wells, two sanctioned development well side-tracks targeting the M9U compartment (with the first well put on production in 2021 and the second well expected to start producing in 2022) and the benefit of the SSMPP implementation (expected to be operational in 3Q 2022). The Low and Best estimate production profiles upon which the Reserves estimates are made are shown in Figure 64.

Figure 64: Shenzi Production Profiles for Reserves Cases





Source: GaffneyCline from BHP Petroleum Data

Contingent Resources are associated with unsanctioned future Shenzi East M9/M10 opportunities that include conversion of an existing producer to an injector, side-track of a watered-out producer in the B203 Block to the Shenzi East Block, and an additional pair of infill vertical producer/injection wells.

BHP Petroleum has identified additional potential opportunities beyond those listed above, including future infill wells, sidetracks or workovers, and facility design life extension that might offer upside potential in the future, but for which no Contingent

Resources have been attributed on the basis that they are not yet been adequately substantiated.

Estimated gross 2C Contingent Resources (Development Unclarified) for the combined group of three projects is 35 MMBbl of liquids and 9 Bscf of gas.

7.1.4 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

For the 1P and 2P Reserves, CAPEX is primarily allocated for two well sidetracks combined with the installation of a subsea multi-phase pumping system. CAPEX in the Contingent Resource case comprises of a series of well related projects to increase production, including new wells, side-tracks or well conversions. The BHP Petroleum CAPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience.

Gross CAPEX for development of the Shenzi Reserves case is estimated to be US$59 MM and gross CAPEX for development of the Shenzi Contingent Resources case is estimated to be US$439 MM.

The OPEX estimates for the Reserves and Contingent resources were evaluated by GaffneyCline, taking into consideration the planned activities and work programs outlined in the documentation. The total OPEX is broken down into lifting costs, processing and storage, workovers, transportation, and overhead costs. Of these cost components transportation and processing and storage are variable, proportional to the production rate.

The OPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted to account for changes in the variable OPEX components of the total OPEX resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

For the 1P and 2P Reserves cases and the Contingent Resources case, ABEX costs have been reviewed and adopted unchanged.

7.2 Shenzi North and Wildling

The Shenzi North and Wildling oil fields, which were discovered in 2015 and 2017 respectively, make up the greater Wildling development area, located directly north of the BHP Petroleum operated Shenzi development. The Shenzi North development is focused on GC608 and GC609 while the Wildling development is focused on the GC564 and GC520 blocks in the North (Figure 60). Both Shenzi North and Wildling are operated by BHP Petroleum with working interests of 72% and 100% respectively. Repsol holds the remaining 28% working interest in Shenzi North.

7.2.1 Field Description

The greater Wildling discovery consists of Miocene turbidite sandstone reservoirs charged by oil originating from the Jurassic-Tithonian source rocks. The field has a large footprint with complex trap edges that are not well defined. Greater Wildling was discovered and partly appraised with the Shenzi North well, which had three side-tracks, giving a total of four reservoir penetrations. The field was further appraised with the Caicos and Wildling-2 (two penetrations) wells. Well Winding-1 in GC521 was abandoned during drilling before reaching reservoir depth.

The original seismic interpretation of the greater Wildling area was from a re-processed 2018 CGG 25Hz RTM (Reverse Time Migration) as well as a Kirchhoff Pre-Stack Depth Migration (PSDM) product. BHP Petroleum has recently purchased a new Ocean Bottom Nodal (OBN) seismic data set that is being integrated into new maps in the area. Seismic resolution of the new OBN seismic dataset is an improvement over the previous data, however low frequency at target depths limits vertical resolution of the seismic especially in high signal to noise areas. Furthermore seismic character varies from well to well across the basin at the target M10U interval.

Based on pressure and fluid observations it is known that the Caicos area is isolated from both Wildling and Shenzi North areas within the main M10U horizon. Some uncertainty remains on the exact location of pressure/fluid boundaries between the wells.

The majority of the STOIIP and the expected ultimate recovery is contained within the primary target M10U reservoir sands. M10U is interpreted as being a lobe dominated system throughout most of the greater Wildling area. The secondary reservoirs (M7, M8 and M9) are interpreted to be channelized turbidites that are aerially discontinuous and have lower net to gross compared to the M10U sand. The secondary targets are assessed to have significantly smaller volumes compared to the primary M10U reservoir.

The primary M10U formation has been found at depths of 8,200 to 9,630 mss in the development area, with average porosity of ~15% and average permeability of about 32 to 50 mD. The greater Wildling area contains a highly under-saturated oil with reservoir pressure ~17,150 psia and saturation pressure ~1,788 psia. Oil gravity is 30 to 32 °API, GOR is 380 to 520 scf/stb and viscosity is 1.7 to 2.8 cP.

7.2.2 Field Development

The current conceptual development plan is a daisy-chained subsea tie-in to existing Shenzi production facilities and will benefit from the planned SSMPP for the Shenzi TLP. Shenzi North development comprises two producers, SN101 and SN102, in leases GC608 and GC609 respectively. Well SN101 was drilled late 2020 to early 2021. The proposed Wildling field development comprises two oil producers; Well J101 in lease GC564 and Well J102 in lease GC520.

The Shenzi North development entered Execution phase in 2021 after project sanction by BHP Petroleum in August 2021 and by Repsol in September 2021. The Wildling field development is currently in Definition phase, with project sanction possible in late 2022, depending on the results of drilling of the appraisal/development well J101.

Both the Shenzi North and Wildling projects target areas with large STOIIP and the expected recovery factors based on depletion drive are modest. BHP Petroleum is considering water injection as a possibility for future phases of development to improve recovery. Understanding of reservoir quality, connected volume and potential baffles gained from the production performance under depletion drive will help to plan a waterflood.

7.2.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

The Shenzi North and Wildling development plans each comprise of two well subsea tiebacks to the Shenzi tension leg platform, including manifolds, high integrity pressure protection systems, and multi-phase flow meters.

BHP Petroleum's CAPEX estimates for both Shenzi North and Wildling have been reviewed and appear to be credible, based on GaffneyCline's experience. Gross CAPEX for development of the Shenzi North Reserves case is estimated to be US$349 MM and gross CAPEX for development of the Wildling Contingent Resources case is estimated to be US$650 MM.

The OPEX estimates were evaluated by GaffneyCline, taking into consideration the planned activities and work programs outlined in the documentation. The total OPEX is broken down into lifting costs, processing and storage, workovers, transportation, and overhead costs. Of these cost components transportation and processing and storage are variable, proportional to the production rate.

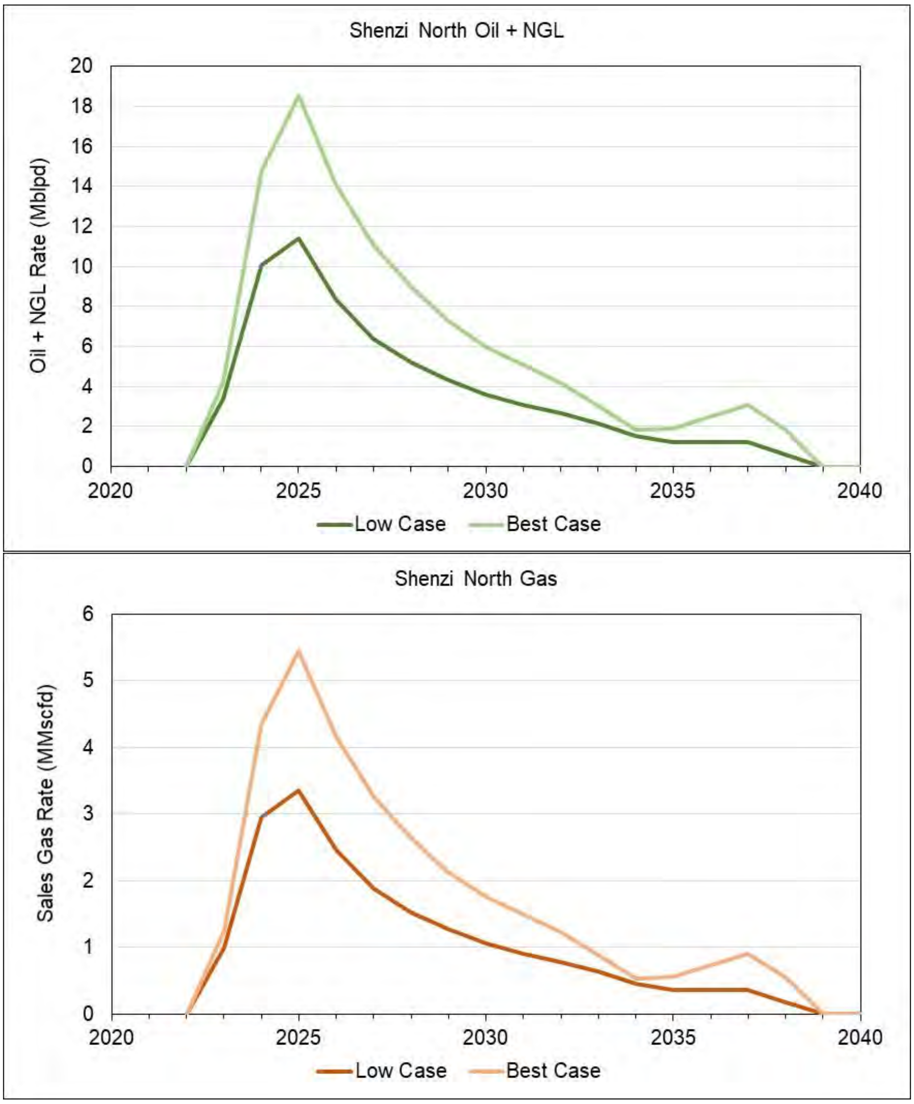
The OPEX costs have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted to account for changes in the variable OPEX components of the total OPEX resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

7.2.4 Resources Estimates

GaffneyCline reviewed the static geological and simulation models, sensitivity runs and analogue study that form the basis for the production forecast for the greater Wildling development project. Both the static and simulation models reflect reasonable best effort interpretations given the limited well data over a large area and uncertainty in reservoir quality, continuity, and deliverability. In absence of actual well test and production history, oil recovery per well in the K2 field to the West and Shenzi West segment to the south have been used to assess reasonableness of the estimated recoverable volumes per well in the Greater Wildling simulation models. However, GaffneyCline notes that there is still uncertainty in these estimates since the greater Wildling area is targeting the M10 formation at slightly deeper depths and lower porosity than the K2 and Shenzi West wells.

Reserves are attributed to two sanctioned development wells in Shenzi North: SN101 targeting the M10U and M9L reservoirs, and SN102 targeting M10U and M7U3 reservoirs. Both wells are expected to start production in 2024. The Low and Best estimate production profiles upon which the Reserves estimates are made are shown in Figure 65.

Figure 65: Shenzi North Production Profiles for Reserves Cases



Gross 2C Contingent Resources (Development Pending) of 37 MMBbl oil and 11 Bscf gas are attributed to Wildling. Additional Contingent Resources for water injection that are currently carried by BHPP as Development Not Viable are not reported here.

7.3 Atlantis

The Atlantis Field was discovered in 1998 in Gulf of Mexico Green Canyon Blocks 699, 742, 743 and 744 (Figure 57) in water depths of 1,370 to 2,130 m. The field is operated by BP (WI 56%) and BHP Petroleum holds 44% WI.

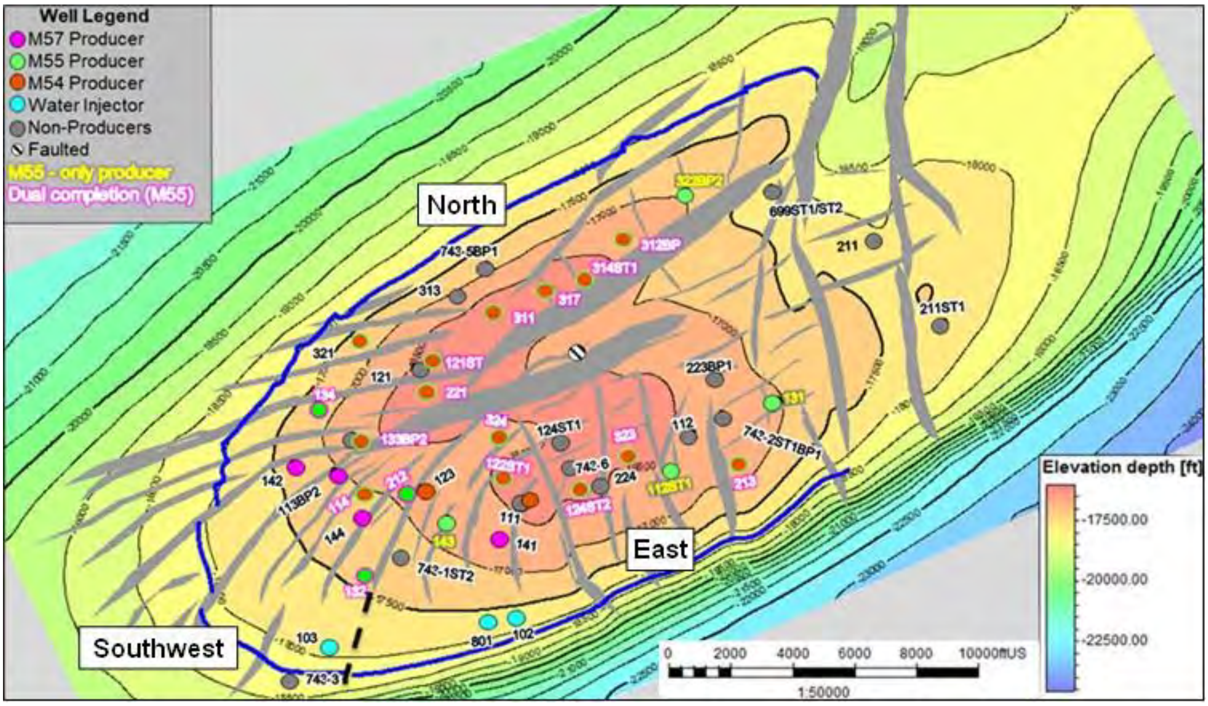
7.3.1 Field Description

The Atlantis structure is a large, southwest to northeast trending faulted anticline (Figure 66). Much of the field contains normal faults that radiate outward from the crest, subdividing the field in several structural compartments. The three major compartments are North, Southwest and East, though the field can be further subdivided into more compartments.

Atlantis straddles the southern limit of the overlying allochthonous salt in the subsurface and the resulting Sigsbee Escarpment. The salt canopy covers some 60% of the field impacting seismic quality with the best quality seismic in the south-west area of the field that is not under the salt canopy.

The original seismic dataset was a 2005-vintage rich-azimuth survey reprocessed several times to an RTM (Reverse Time Migration) as well as a Kirchhoff Pre-Stack Depth Migration (PSDM) product. Recently, new Ocean Bottom Nodal (OBN) seismic data set was acquired. The seismic had a dual purpose; first, to improve imaging of faults internal to the field to define possible flow barriers and second, for the purpose of generating 4-D (time lapse) seismic. The results of the 4-D seismic interpretation have been very beneficial in targeting future wells especially in the Southwest compartment.

Figure 66: Atlantis Top M55 Reservoir Structure Map



Source: BHP Petroleum

The objective intervals are the Middle Miocene age (M57, M55, M54 and M53) deep-water turbidite sandstone reservoirs encountered at depth ranging from 4,900 to 5,600 mss (Figure 67). These sands are interpreted as turbidite basin-floor sheet fans.

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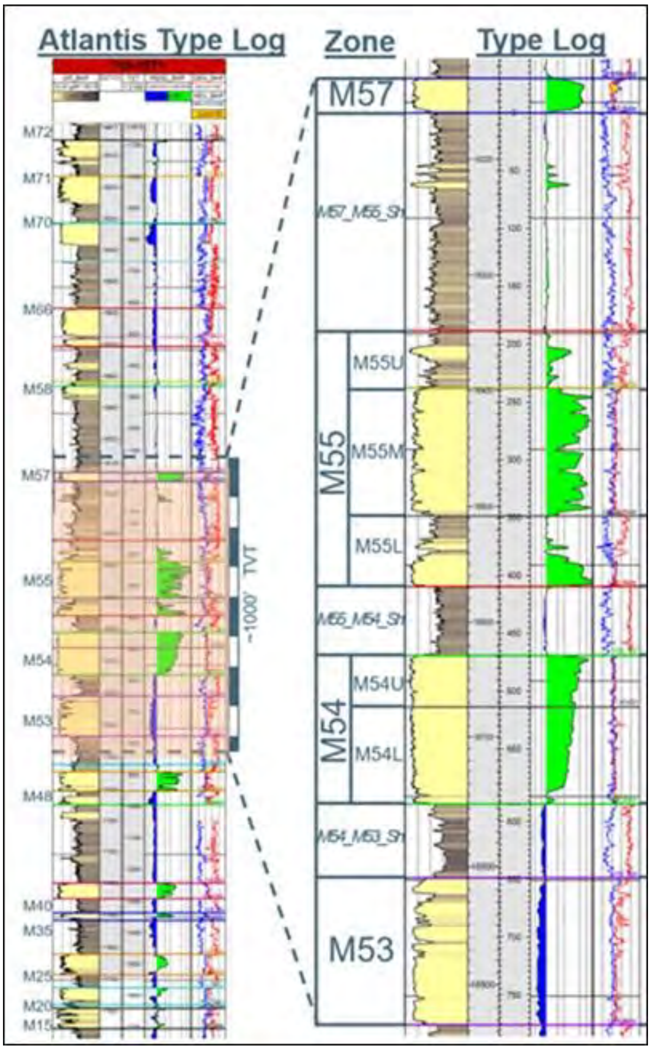
Other secondary reservoirs in the field are the lower Miocene (M48/M40) and deep Miocene (M35 to M15) sands that have been found to have hydrocarbons, predominantly higher viscosity oil than the Middle Miocene sands. Various gas bearing intervals have also been encountered.

Figure 67: Atlantis Type Log



Source: BHP Petroleum

MWD/LWD, wireline, static pressure, fluid data and whole cores (from some wells) have been obtained and show that sand and fluid quality are laterally consistent and predictable, unless faulted out. Well logs and core information indicate sands are high quality with average porosity of 27 to 30% and average permeability of 600 mD to 850 mD.

The M54 and M55 reservoirs contain under-saturated oil while the M57 fluid has a higher bubble point oil with free gas being found in various locations in the Southwest/East section of the field. In general oil gravity ranges from ~25 to 31° API and oil viscosity is 1.6 cP to 2.95 cP (excluding the Lower/Deep Miocene reservoirs).

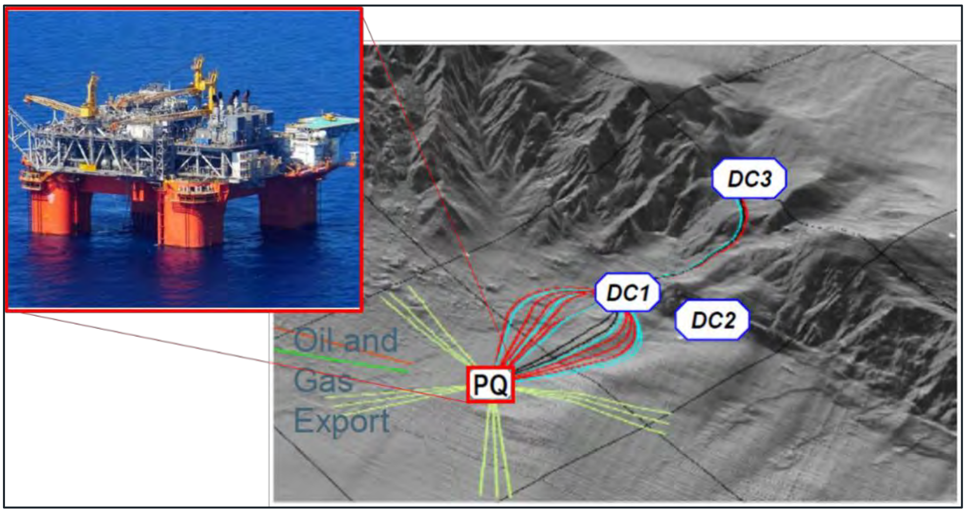
The associated 'wet gas' produced with the crude oil is further processed onshore to remove natural gas liquids (NGL) and condensate.

7.3.2 Field Development and Production Profiles

The Atlantis development concept comprise three drill centres that are connected to a moored semi-submersible PQ (production quarters) facility with subsea flowlines (Figure 68).

The production facility has oil and gas production handling capacities of 200 Mbopd and 180 MMscfd respectively. The facility is also designed for produced water handling and water injection capacities of 75 Mbwpd, however current produced water handling capacity is 40 Mbwpd and current water injection capacity is 50 Mbwpd. The facility has a design life up to 2039, and there are plans to extend the life to 2047.

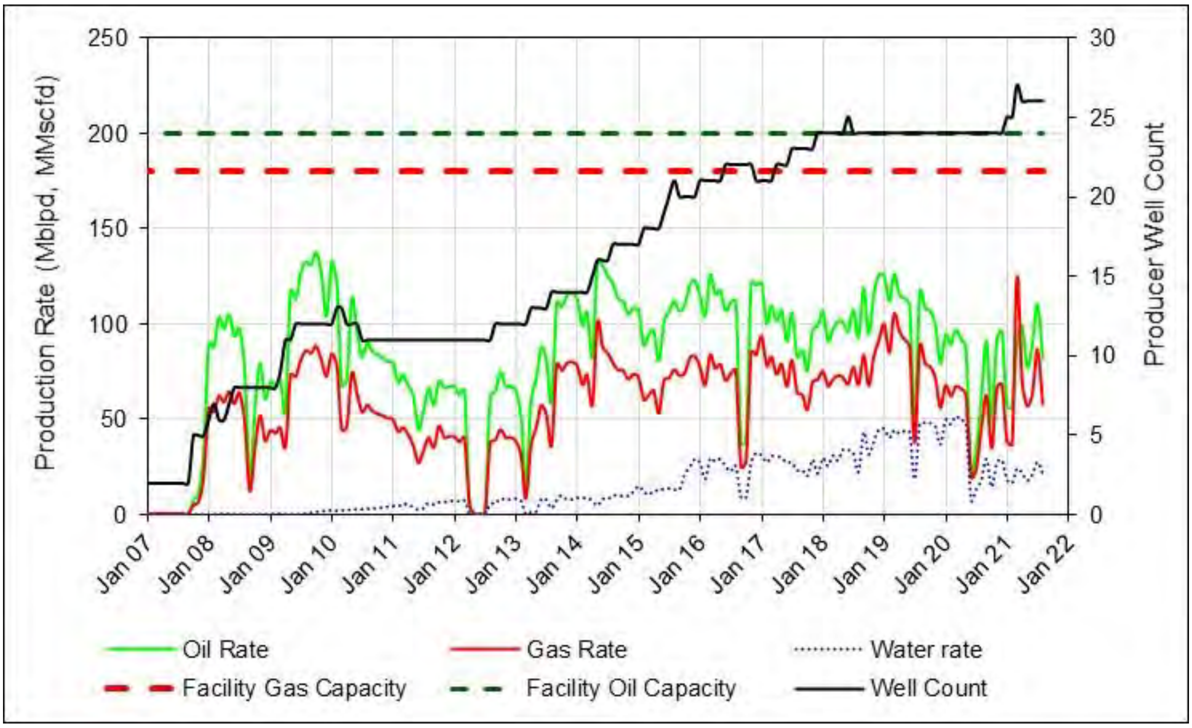
Figure 68: Atlantis Facility Overview



Source: BHP Petroleum

About 46 wells including side-tracks have been drilled in Atlantis, of which 29 are producers and three are water injectors (Figure 66); three producers and one injector are currently offline. Peak oil production of ~138 Mbopd occurred in 2009 and the production rate as of August 2021 was about 82 Mbopd (Figure 69).

Figure 69: Atlantis Historical Production



Source: BHP Petroleum

Oil and sales gas are exported through the Caesar and Cleopatra export pipeline system. BHP Petroleum equity is 25% in the Caesar pipeline and 22% in the Cleopatra pipeline.

The Atlantis field has been developed in a phased approach: Phase 1 development from 2009 to 2010 and Phase 2 from 2013 to 2017. Phase 3 development was sanctioned in February 2019 and the Phase 3 drilling/completion campaign began in October 2019 (expected to end Q1 2023), consisting of eight new wells targeting one or two intervals in M54/M55/M57 and two subsea 4-well manifolds. By September 2021, five of the eight Phase 3 wells had been drilled, with three being completed and put online and two requiring sidetracks. For one of the two wells requiring a sidetrack, the target location is not yet firm and estimates of potentially recoverable volumes are currently classified as Contingent Resources. Beyond Phase 3, continuous drilling (yet to be sanctioned) is assumed until 2029 to bring online 12 additional producers and five water injectors.

There is some uncertainty in the amount of future water injection well drilling and facility expansion due to the production evidence of strong aquifer support in the North and Southwest areas of the field. BP and BHP Petroleum believe that there is potential upside to be realized from water injection in East M54/M55 and the opportunity assessment is being progressed, as well as the M57 in the Southwest. This opportunity will require an increase in water injection capacity from the current 50 Mbwpd to slightly over 113 Mbwpd.

One of the future Phase 3 wells is planned to be a dual zone M57/M55 well, and another an M57 horizontal producer. After Phase 3, the M57 may be further developed by two injectors and two producers.

The M53 reservoir is completed in the North 312 well, as the lower interval in a smart completion with the M55/54 commingled in the upper completion. The M55/M54 completion is being produced in cycles due to low reservoir energy in the area. There is opportunity to produce the M53 sand when the M55/M54 completion is shut-in. Currently, two M53 wells are carried in Contingent Resources: one dual-zone M55/M53 well in the East and one dual-zone injector in the East.

There are currently no producers in the M40 and M48 reservoirs. A Phase 3 well found oil with higher viscosity than the Middle Miocene in one these reservoirs. There is no immediate plan to develop these reservoirs.

7.3.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation.

BHP Petroleum CAPEX estimates have been reviewed for each of the 1P, 2P and Contingent Resources cases.

For the 1P and 2P cases the CAPEX appears to be credible, based on GaffneyCline's experience of comparable scopes. Gross CAPEX for development of the Atlantis Reserves case is estimated to be US$624 MM.

The Contingent Resources CAPEX comprises of a series of projects including:

- DC322ST and WIX50 – a well sidetrack plus drilling of 2 new injector wells to utilise the current water injection capacity;
- DC1, DC2, and DC3 expansions, involving drilling a total of 11 new producer wells; and
- MFX-SSMPP, involving the drilling of 4 new injectors to increase water injection capacity and installation of subsea multiphase pumps to provide artificial lift, reducing manifold pressures and accelerating production.

The BHP Petroleum CAPEX estimates for each of the projects have been reviewed and appear to be credible, based on GaffneyCline's experience of comparable developments. Adjustments have been made to the CAPEX to reflect the removal of one of the four producers wells in the DC2 development (well G54), and one of the four producers wells in the DC3 development (well X54).

The OPEX estimates provided in the economic model and supporting documentation have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted in the 1P, 2P and Contingent Resources cases to account for changes in the variable OPEX components of the OPEX costs resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

Table 53: Atlantis Gross CAPEX Estimates for Contingent Resources

Item	CAPEX (US$MM)
DC322ST and WIX50 Development	227
DC1 – Development	221
DC2 – Development	253
DC3 – Development	259
MFX -SSMPP - Development	747
Total	**1,707**

7.3.4 Resources Estimates

Reserves in Atlantis are associated with existing producing wells and approved outstanding Phase 3 wells. GaffneyCline reviewed the simulation models that form the basis for the production forecast for these activities, in particular the history match to existing wells' production and pressure data, and found the models and forecasts to be reasonable. The Low and Best estimate production profiles upon which the Reserves estimates are made are shown in Figure 70.

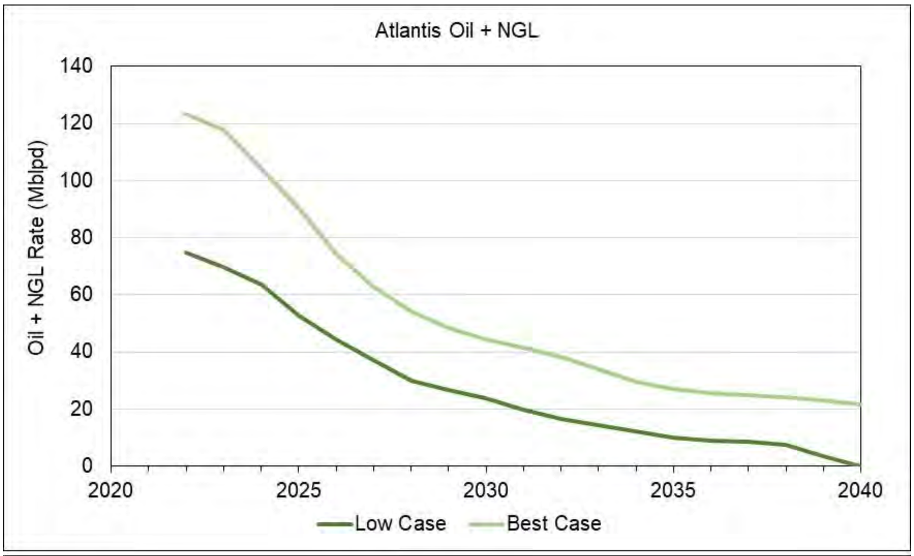
Contingent Resources are attributed mostly to asset development projects being actively worked on, but yet to be sanctioned (Table 54):

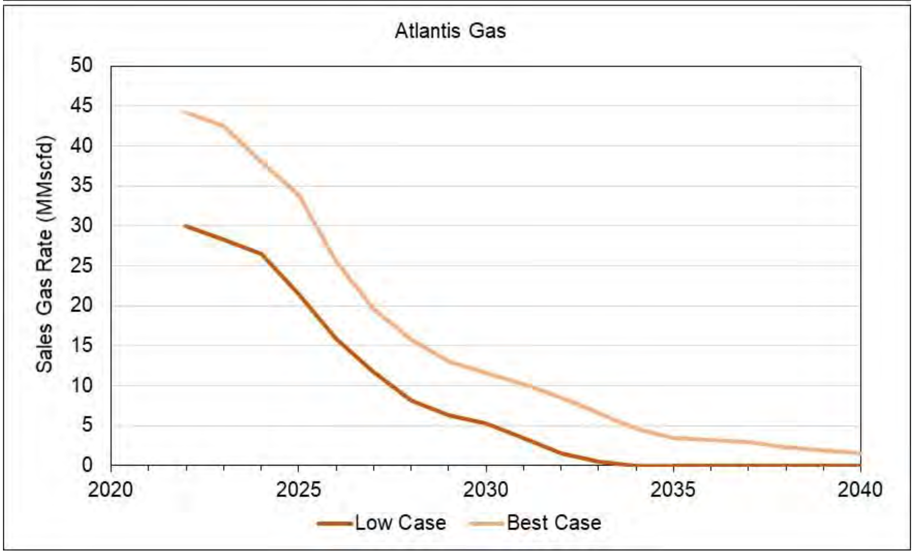
- One to two new water injection wells and a sidetrack of a failed producer to the central compartment targeting the M55/M53 reservoirs.
- Expansion of Drill Centre 1 with three new infill wells targeting the M57/M55/M54 reservoirs.
- Facilities expansion to incorporate subsea multiphase pumps (SSMPP) that will boost production as well as four new water injectors for the M57/M55/M54/M53 reservoirs.
- Expansion of Drill Centre 3 with four infill wells in reservoirs M55/M54.
- Expansion of Drill Centre 2 with four infill wells in reservoirs M55/M54.

GaffneyCline reviewed the profiles associated with these incremental activities and found most to be reasonable. However, for a variety of technical reasons, GaffneyCline made downward adjustments to the incremental volumes attributed to the G54 producer in the Southwest compartment, wells WI_Un54, X54 and Ve54 in the East compartment, and well nF54 in the North compartment.

GaffneyCline has not reported Contingent Resources for the Lower and Deep Miocene reservoirs that have been found to have high viscosity crude, or to potential late life shallow gas development and facility design life extension beyond 2047, all of which are currently considered not viable based on their preliminary technical and economic assessment.

Figure 70: Atlantis Production Profiles for Reserves Cases





Source: GaffneyCline from BHP Petroleum Data

Table 54: Atlantis Gross 2C Contingent Resources as at 31st December 2021

Project	Gross 2C Contingent Resources		Development Status
	Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Water injectors and a sidetrack producer	37.8	16.6	Unclarified
Expand Drill Centre 1 with three wells	40.0	16.1	Unclarified
SSMPP and four water injection wells	74.3	31.7	Unclarified
Expand Drill Centre 3 with four wells	22.2	10.3	Not Viable
Expand Drill Centre 2 with four wells	26.5	12.1	Not Viable

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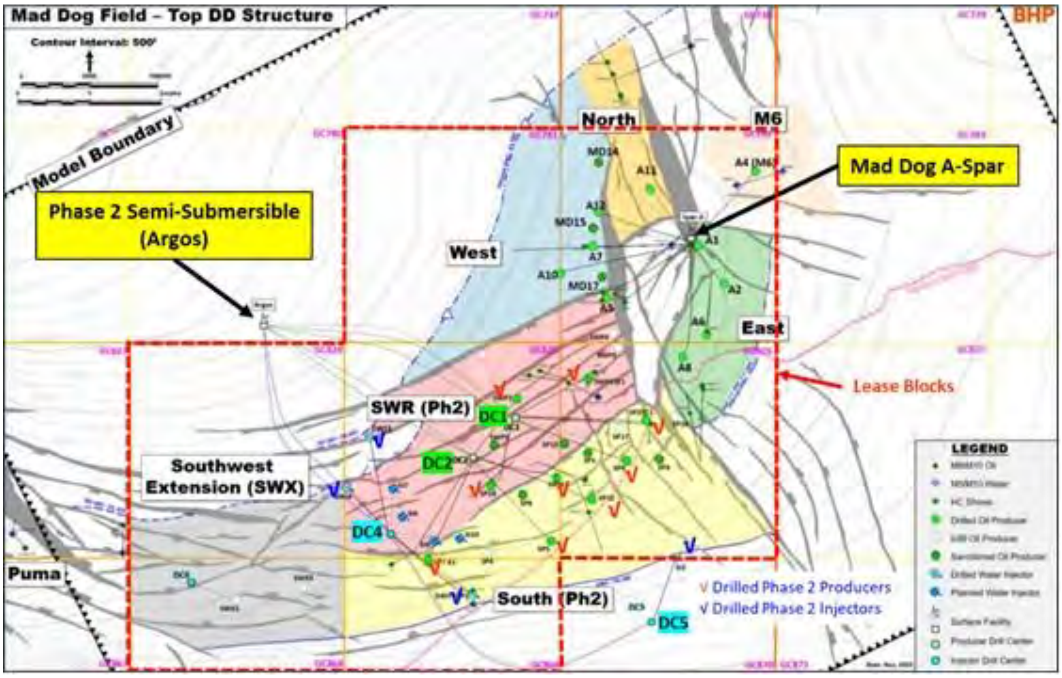
7.4 Mad Dog

The Mad Dog Green Canyon 826 Field was discovered in 1998 in the Gulf of Mexico in approximately 1,340 m water depth (Figure 57). The Mad Dog Lease area comprises seven blocks in the Green Canyon area; GC 781, 782, 824, 825, 826, 868 and 869 (Figure 71). The field is operated by BP (WI 60.5%) and BHP Petroleum and Chevron hold 23.9% and 15.6% WI respectively. First production occurred in January 2005. There are ten producing wells (Figure 71).

Figure 71: Mad Dog Field Overview, Structure Map, Wells and Facility Locations



Source: BHP Petroleum

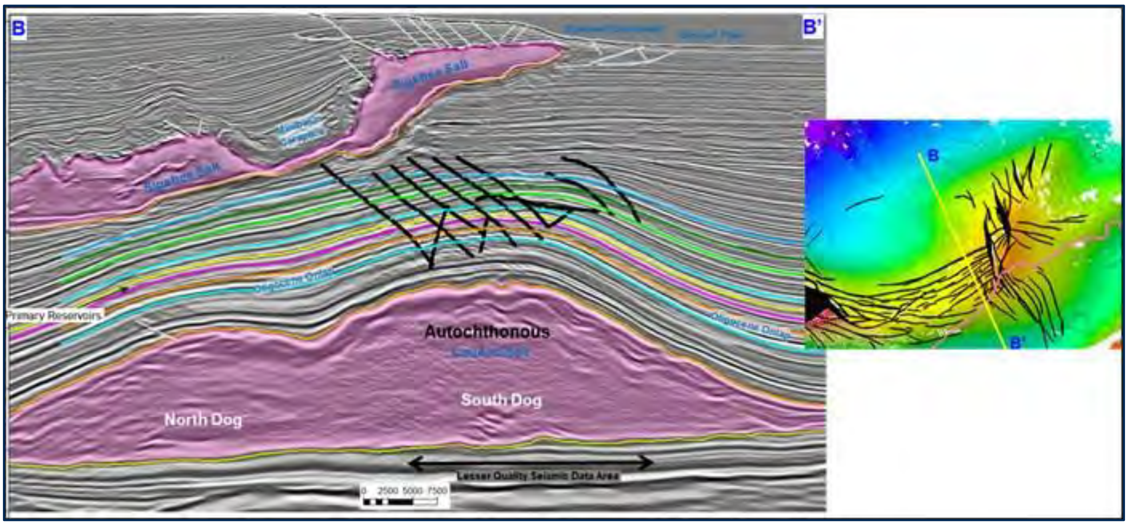
7.4.1 Field Description

The Mad Dog field is a large, north-south trending, faulted, compressional anticline in the Western Atwater Fold Belt with oil trapped in Middle (M6) and Lower Miocene (M9/M10) turbidite reservoirs. Over 75% of the field is overlain by the Sigsbee Salt; the Sigsbee salt limit (pink line in Figure 71) runs diagonally from SW to NE across the southern flank of the field.

The field contains a series of normal faults that radiate outward from the crest, subdividing the field into several structural compartments. The five major field compartments are East, North, West, Southwest Ridge (SWR) and South (Figure 71). The Southwest Extension (SWX) is an extension of the SWR and South compartments, though several other compartments could be interpreted.

The Mad Dog structure is supported by an autochthonous salt body (Figure 72), with associated extensional faults forming a crestal graben. In spite of being at the crest of the structure, the graben area does not have trapped hydrocarbons.

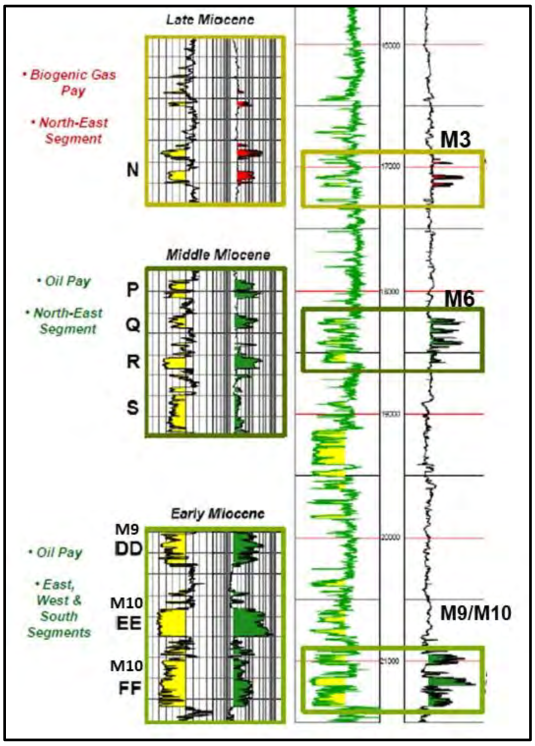
Figure 72: Seismic Cross Section through Mad Dog



Source: BHP Petroleum

A Mad Dog type log and the stratigraphic nomenclature used at Mad Dog field is shown in Figure 73.

Figure 73: Mad Dog Type Log



Source: Walker, C. D., and G. A. Anderson, 2016, Simple and efficient representation of faults and fault transmissibility in a reservoir simulator: Case study from the Mad Dog Field, Gulf of Mexico: GCAGS Explore & Discover Article #00177, http://www.gcags.org/exploreand discovery/2016/00177_walker_and_Anderson.pdf Gulf Coast Association of Geological Societies.

The primary reservoirs are thick, blocky Lower Miocene (M9/M10) sands, designated as M9DD, M10EE, and M10FF. At Mad Dog individual sands are often more than 30 m thick and are stacked/amalgamated into 100 to 120 m thick sand packages with good porosity of 24% to 27% and permeability of about 500 to 650 mD. The M9/M10 reservoirs are oil bearing in the East, West, North, South West Ridge and South segments of the structure. Some of the interbedded shales are likely to be continuous and may be flow barriers while others are limited in extent and may be flow baffles. Actual oil-water contacts (OWCs) for the Lower Miocene sands were intersected in two wells.

The Mad Dog Deep 2 well encountered an OWC in the M10 FF Sand in the south-eastern portion of the field. On the west side, an OWC was intersected in the M10 FF sands by the Mad Dog-11 down dip appraisal well. On the South side, an ODT was encountered in the Lower Miocene sands in the MDS-ST1 down dip appraisal well. The Northern appraisal wells (down dip) encountered oil in the M9 and oil and water in the M10. The A-11 North graben well drilled in 2016 encountered oil all the way to the base of the M9/M10 sand.

The oil in the M9/M10 is undersaturated with oil gravity ranging from 26.5 to 33° API and oil viscosity from 2.17cP to 7.61 cP.

The M9 CC sand, Upper Miocene (M3) and Middle Miocene (M6) are minor reservoirs. Oil has been encountered in the CC and M6 and gas has been encountered in the M3 reservoir.

The most significant geologic uncertainty associated with the Mad Dog Field is structural complexity (although sand quality is laterally consistent and predictable within the M9/M10 reservoirs). Faults were encountered in most of the wells drilled to date with evidence of some compartmentalization on a field level. The issues revolve around the sealing nature of these faults, the number and location of compartments, volumes within compartments and their connectivity to the aquifer.

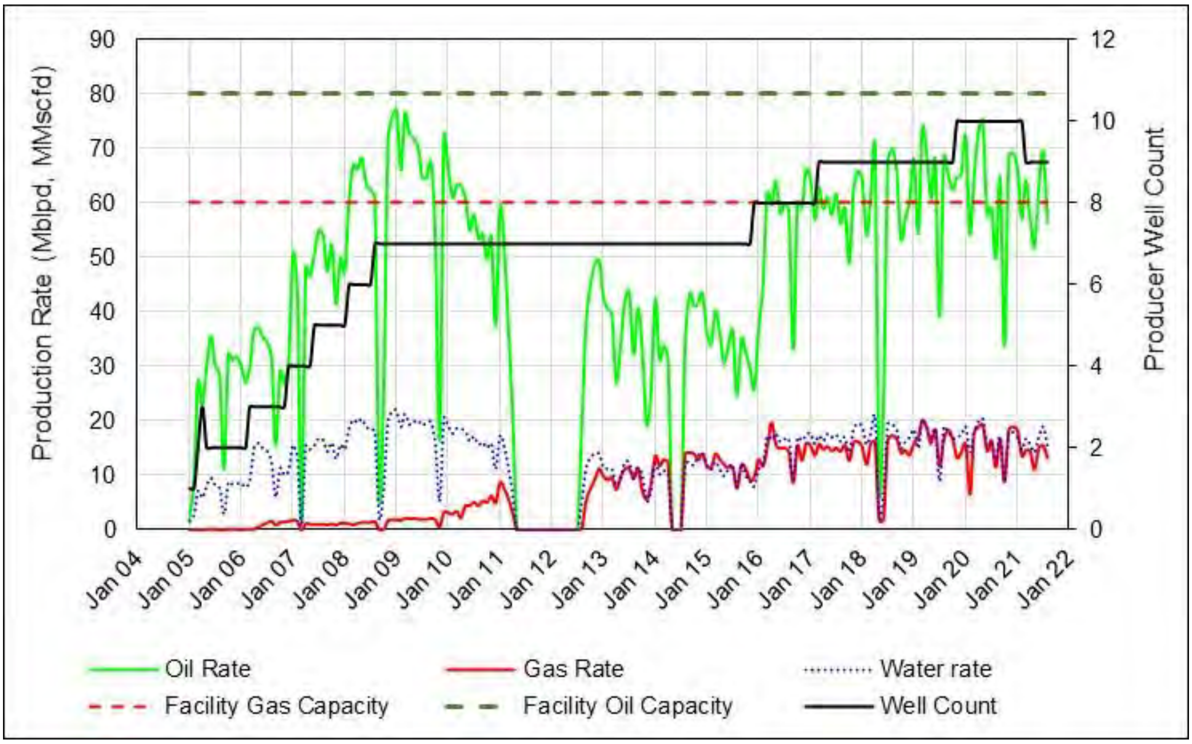
A wide-azimuth towed streamer (WATS) 3D Seismic survey was acquired in 2004-2005 and reprocessed several times between 2006 to 2010 using different migration algorithms with the final product based on using tilted transverse isotropic (TTI) migration. Interpretation of the TTI volume currently serves as the basis for fault placement, segment definition in the field and STOIIP estimation. Subsequent seismic volumes have not been used for any resources estimates but rather used to help validate the existing TTI-based geomodel. An Ocean Bottom Nodal (OBN) 3D seismic survey was acquired between 2017 and 2019. The interpretation from this OBN data (see an example in Figure 72) forms the basis for a recent update to the geological model and new simulation modelling still in progress.

7.4.2 Field Development

The Mad Dog A-Spar facility comprises a 16-slot (capable of 13 production wells), dry-tree, floating spar hull with integrated production and drilling capabilities. It is a production quarters (PQ) truss spar host with an original nameplate capacity of 80 Mbopd (upgraded to 100 Mbopd in 2016), 40 MMscfd of gas, and 50 Mbwpd. Currently, it has no water injection capability. An 8-well gas lift manifold was set in

April 2009. Mad Dog's historical production is shown in Figure 74. Current oil production rates are ~65 Mbopd, with watercut ~20%.

Figure 74: Mad Dog A-Spar Historical Production



Source: BHP Petroleum

The design life of many of the major components of the A-Spar facility is 20 to 30 years, putting the original design life to December 2024. BP has performed a number of studies to quantify both the work scope and CAPEX required to extend the life of the facility to recover the significant remaining potential. BP has adopted 2045 as the end of field life for their business planning purposes.

Oil and sales gas are exported through the Caesar and Cleopatra export pipeline system. BHP Petroleum equity is 25% in the Caesar pipeline and 22% in the Cleopatra pipeline.

The A-Spar development plan has three remaining wells to be drilled in the West segment and two future side-track opportunities (one in the East and the other in the West Segment). Drilling operations are planned to commence in February 2022.

The Phase 2 project, currently in progress, comprises a semisubmersible floating production facility 'Argos' with a name plate capacity of 110 Mbopd and 140 Mbwpd water injection. Fourteen producers and eight water injectors are initially planned from drill centres connected to the facility via subsea flowlines. Nine producers and four injectors in the Phase 2 development plan have been drilled of which six producers and one injector have been completed. Start-up of production is planned for the second quarter of 2022.

GaffneyCline reviewed the simulation models that form the basis for production forecast of the A-Spar existing and future wells, and Phase 2 development wells, and consider them to be reasonable. In particular, GaffneyCline reviewed the quality of the calibration of the models with production and pressure data.

7.4.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation. GaffneyCline has reviewed the CAPEX provided by BHP Petroleum for each of the 1P, 2P and 2C Contingent Resources cases for Mad Dog A-Spar and Mad Dog Phase 2.

Mad Dog A-Spar

For the 1P and 2P Reserves cases costs are related to the original A Spar development (Mad Dog A-Spar Base) and to the A Spar infill programme (Mad Dog Approved).

The Contingent Resources CAPEX costs comprise the following two projects:

- Expansion of the Phase 2 water injection to West and North segments; and
- A-Spar life extension and tie-back to Argos.

Gross CAPEX for development of the Mad Dog A-Spar Reserves case is estimated to be US$355 MM and gross CAPEX for development of the Mad Dog A-Spar Contingent Resources case is estimated to be US$376 MM.

Mad Dog Phase 2

For the 1P and 2P Reserves cases costs comprise of costs related to the second phase of development targeting the southern flank of the field with a semi-submersible floating production unit (Mad Dog Phase 2).

The Contingent Resources CAPEX estimates comprise of the following two projects:

- Infill drilling in the Phase 2 area; and
- Development of the South West Extension area between Mad Dog and Puma.

The BHP Petroleum CAPEX estimates for each of the projects have been reviewed and appear to be credible, based on GaffneyCline's experience of comparable developments.

Gross CAPEX for development of the Mad Dog Phase 2 Reserves case is estimated to be US$611 MM.

Gross CAPEX for development of the Mad Dog Phase 2 Contingent Resources case is estimated to be US$461 MM.

The OPEX costs provided in the economic model and supporting documentation have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted in the 1P, 2P and Contingent Resources cases to account for changes in the variable OPEX components of the OPEX costs resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

7.4.4 Resources Estimates

Reserves are attributed to Mad Dog for future production from existing infrastructure and wells, and for the implementation of Phase 2 with production schedule to start in 2022. The Low and Best estimate production profiles upon which the Reserves estimates are made are shown in Figure 75.

Contingent Resources (Table 55) are attributed to the following future projects:

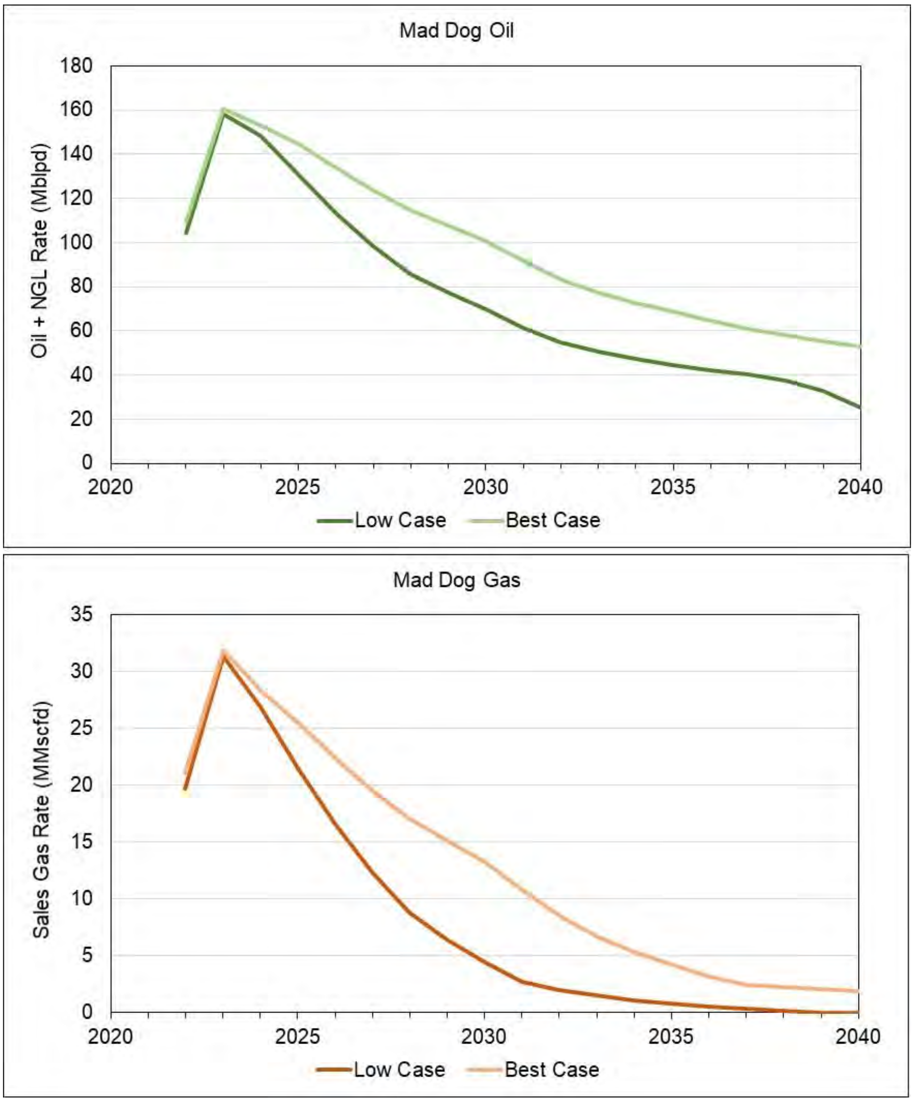
- Expansion of Phase 2 water injection system from 140 to 210 Mbwpd into the West and North segments benefiting A-Spar recovery. Low salinity water injection is planned with the intention of enhancing oil recovery by reducing the residual oil saturation. Decision Gate 2 (end Selection Stage) is expected to be passed early in 2022.
- Development of the South West Extension area between Mad Dog and Puma.
- Infill drilling to supplement the Phase 2 wells, and contingent on the outcome of Phase 2. Three wells are provisionally included in the plan.
- Additionally, Contingent Resources are attributed to extension of the A-spar beyond 2045.

Table 55: Mad Dog Gross 2C Contingent Resources as at 31st December 2021

Project	Gross 2C Contingent Resources		Development Status
	Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Expand Phase 2 water injection	66.7	1.6	Pending
South West Extension	86.7	10.8	Unclarified
Phase 2 supplementary infill drilling	101.6	5.1	Unclarified
A-Spar extension	38.7	-	Unclarified

BHP Petroleum has identified additional potential opportunities beyond those listed above, which might provide upside potential in the future, but for which no Contingent Resources have been attributed on the basis that they are not yet been adequately substantiated.

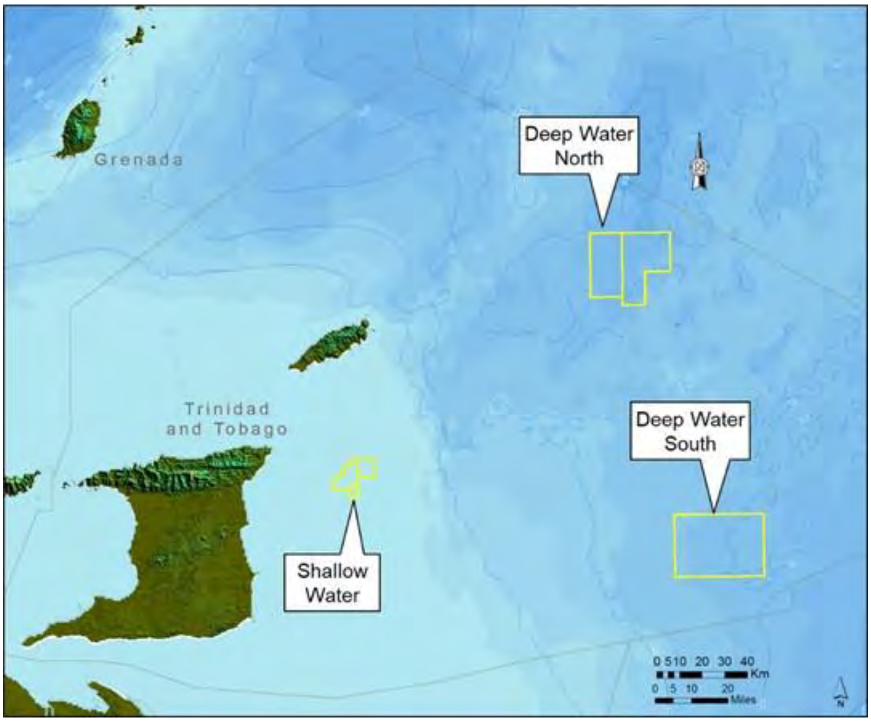
Figure 75: Mad Dog Production Profiles for Reserves Cases



8 BHP Petroleum Trinidad and Tobago

BHP Petroleum holds licences in three offshore areas: Shallow Water, Deep Water North and Deep Water South (Figure 76). The Shallow Water area contains producing oil and gas assets and undeveloped discoveries of the Greater Angostura Complex. The Deep Water North area contains the multi-field Calypso gas development currently under appraisal and the Deep Water South area contains gas discoveries currently under evaluation.

Figure 76: Location Map of BHP Petroleum's assets Offshore Trinidad and Tobago

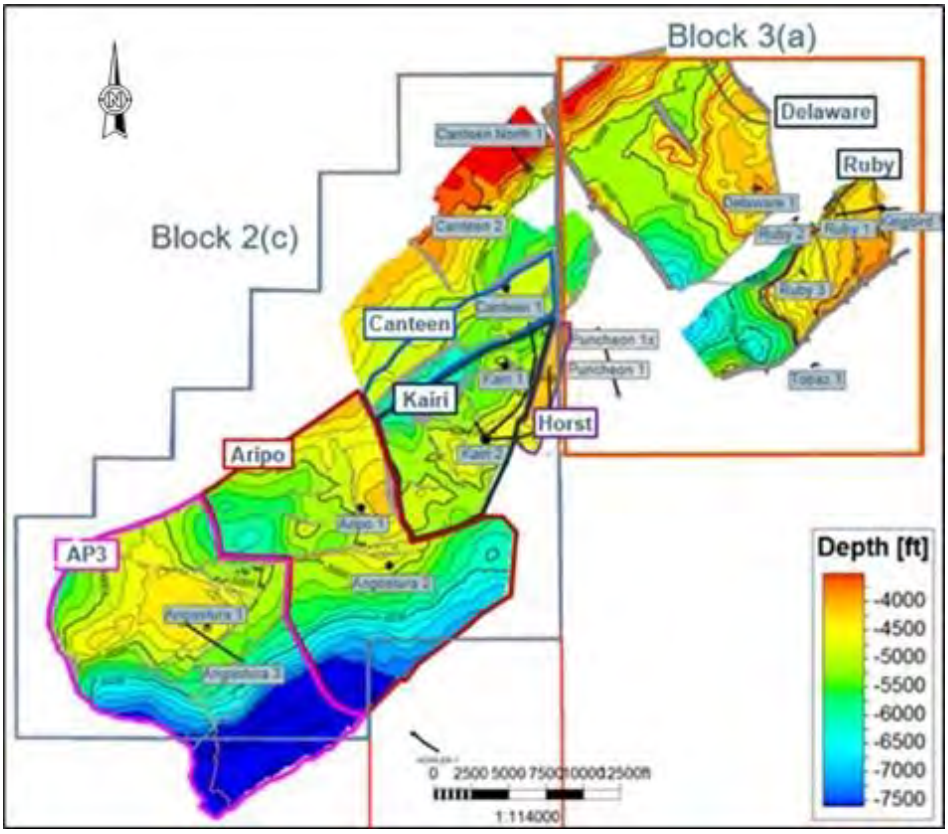


Source: BHP Petroleum

8.1 Shallow Water - Greater Angostura Complex

The shallow water Greater Angostura Complex comprises multiple accumulations located within Block 2(c) and Block 3(a) (Figure 77). Block 2c contains producing oil and gas assets (AP3, Aripo, Horst, Kairi and Canteen) and discoveries (Howler, Canteen North). Block 3(a) contain the Ruby (oil and gas) and Delaware (gas) fields, which came on stream in 2021. BHP Petroleum is the operator under a Production Sharing Contract (PSC) and holds a 45% working interest in the producing assets in Block 2(c) with partners National Gas Company of Trinidad and Tobago (30%) and Chaoyang (25%), and a 68.46% stake in Block 3(a) with the National Gas Company of Trinidad and Tobago as partner. BHP Petroleum has 64.3% working interest in the Howler discovery, which has been incorporated in Block 2(c) with its PSC terms, with Chaoyang as partner.

Figure 77: Location Map of Fields in Greater Angostura Complex



Source: BHP Petroleum

8.1.1 Field Description and Development History

The discovery well Angostura-1, intersected ~290 m of gas in Early Oligocene sands in Block 2(c) in 1999. Oil was discovered by Kairi-1 in 2001, also in Block 2(c). During the Exploration Phase of the Block 2(c) PSC, a total of four exploration and three appraisal wells were drilled, discovering significant oil and gas resources within a large, faulted structure in the same Oligocene sandstone reservoir. Oil rims in Kairi, Canteen and Horst fields have been developed and came on stream from 2005 to 2008. The Aripo and AP3 gas fields came on stream in 2011 and 2016 respectively.

During the Exploration Phase of the Block 3(a) PSC, five exploration and two appraisal wells were drilled. Gas was discovered in Delaware-1 in 2003 and oil in Ruby-1 in 2006. Declaration of Commerciality for Block 3(a) was in 2018 and development of Ruby and Delaware fields was sanctioned in 2019. Development drilling in Ruby started late in 2020 and production is to the Block 2(c) facilities. First oil production from Ruby started in May 2021 and first gas production from Delaware commenced in August 2021.

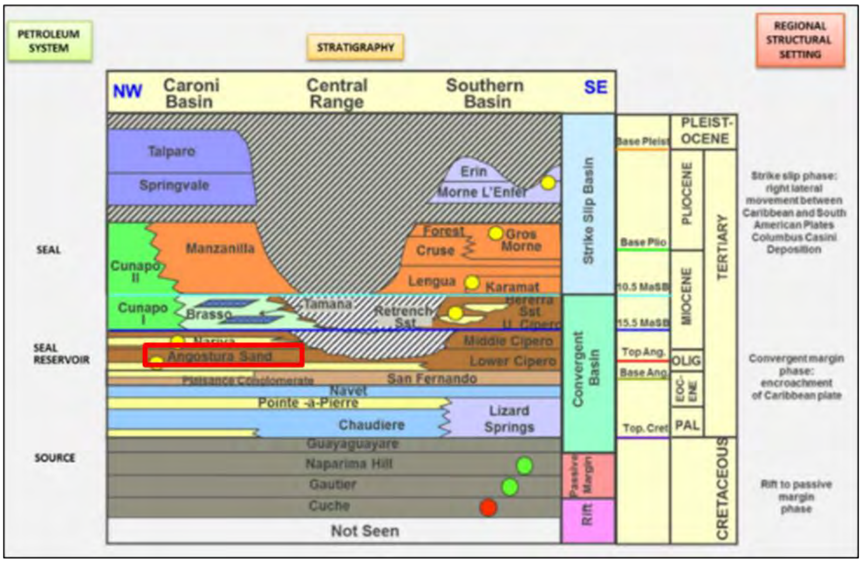
With the development of Ruby and Delaware fields in Block 3(a), the PSC for both Block 3(a) and Block 2(c) has been extended to 2031.

The broad antiformal feature of Greater Angostura is in an area with complex tectonic history and the faults in the field create an intricate structural picture. Major faults have compartmentalized the Greater Angostura structure into at least five or six separate production units. However, due to the high sand content and the large gross thickness, many of the intra-field faults are not completely sealing, but may act as partial flow barriers over the producing life of the field. Most of the tested fault blocks appear to contain different gas-oil and oil-water contacts, and between some blocks, different pressure regimes.

AP3 and Aripo have thin oil rims (11 m) with large gas caps. The Canteen-1 and Kairi compartments contain thicker, but separate, oil columns (96 and 133 m respectively) with gas caps. The Horst block has a 30 m oil rim with a large gas cap.

The fields produce from an Early to Middle Oligocene-aged sand formation named the Angostura Sandstone (Figure 78). It ranges in thickness from less than 100 m to over 450 m. The Angostura Sandstone is interpreted to be a turbidite-dominated gravity flow depositional system in the upper to mid-slope environments, either a fan delta-fed slope or a detached turbidite system, relatively close to its source area. The depositional model is described by a series of laterally coalescing, northwest derived shelf type fan deltas that are banked against a northeast-southwest trending thrust fault bordering an Oligocene 'Northwest Trinidad High.

Figure 78: Stratigraphic Column of Greater Angostura Complex



Source: BHP Petroleum

The structure was originally covered by a 3D OBC (Ocean Bottom Cable) seismic dataset obtained in 1997. The quality of these data and the complexity of the structure left a large amount of uncertainty in the mapping. Since then, several newer 3D seismic surveys (Angostura in 2001, Darien 2003, Emerald 2004) have been acquired and processed for better seismic imaging. The Angostura Field seismic survey was reprocessed and a PSDM volume was delivered in 2005 to improve resolution. In 2008 another reprocessing project was carried out utilizing the latest technologies.

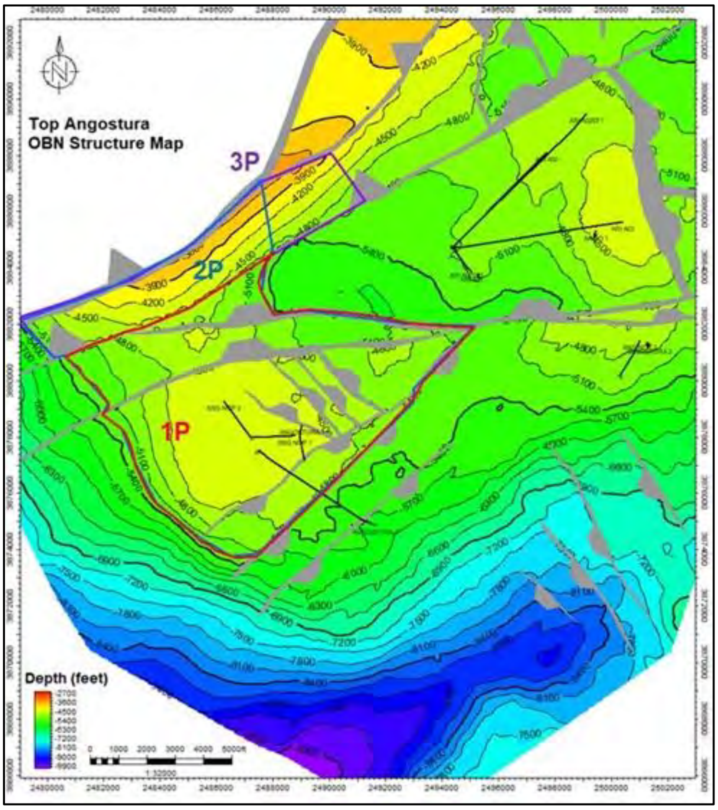
However, imaging remained a challenge and the ability to map top and base reservoir away from well control remained difficult.

The 2018 Trinidad OBN (Ocean Bottom Node) seismic survey was designed to improve imaging to inter alia plan the placement of the horizontal wells of the Ruby development. Processing used Full Waveform Inversion technology and allowed for higher confidence in defining reservoir extent.

AP3 Field (Block 2(c))

Six wells have been drilled in the AP3 Field. Angostura-1 was the discovery well and encountered a gas filled Angostura sandstone interval. Angostura-2 was an appraisal well drilled northeast of the discovery well and found a gas interval that was lower in pressure than the original well and a thin oil column (11 m) with water bearing sandstone below. The Angostura-3 appraisal well was drilled between the other two previous wells and encountered a thin gas section apparently connected to the discovery well, then faulted into a water bearing sand which looks to be the Angostura-2 reservoir. As part of the AP3 project, three development wells were drilled and completed. These are currently all on production. Dynamic data show larger GIIP than estimated by mapping seismic data around the wells. Connected GIIP has been estimated using multi-tank material balance and diagnostic plots. Low and Best estimate resources estimates are based on material balance and history matched reservoir simulation models respectively (Table 56).

Figure 79: Depth Structure Map of AP3 Field



Source: BHP Petroleum

Aripo Field (Block 2(c))

Four wells have been drilled in Aripo. Aripo-1 found gas bearing Angostura Sandstone with a thin oil column and water bearing sand. Pressures suggest a possible connection between the Angostura-2 eastern area and Aripo-1. Three development wells were drilled and completed. Pressure decline due to production from the Kairi field indicates communication between these fault blocks. Over 90% of the ultimate recovery has been produced. Resources estimates are based on well performance extrapolation using 500 psi abandonment pressure (Table 56).

Kairi Field (Block 2(c))

Kairi Field, discovered by Kairi-1 and appraised by Kairi-2 has been the predominant oil producing segment of the Angostura complex. To date 15 development wells have been drilled from the two wellhead platforms (excluding Kairi Horst). Eleven are horizontal or highly deviated oil producers and four are gas injection wells. Development drilling has confirmed the geologic complexity of the area. Additional faulting and different fluid contacts have been encountered in some of the wells. Low and Best estimate Resource estimates are based on DCA and reservoir simulation respectively (Table 56). More than 95% of the ultimate recovery has been produced.

Canteen Field (Block 2(c))

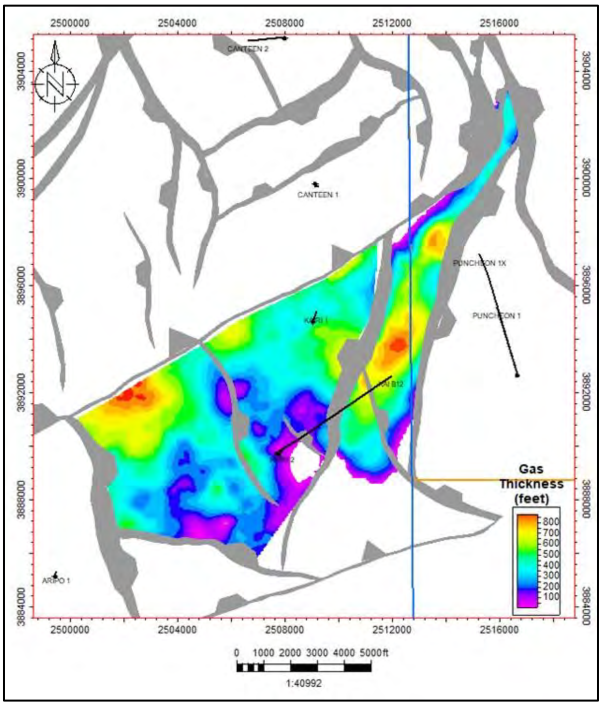
The Canteen oil accumulation was discovered by Canteen-1. Seven development wells were drilled: four horizontal oil producers and one deviated gas injection well in the main producing area of Canteen, and a gas injector to support a horizontal oil producer that was drilled into the western area. Low and Best estimate Resource estimates are based on DCA and reservoir simulation respectively (Table 56). More than 97% of the ultimate recovery has been produced.

Horst Field (Block 2(c))

A well drilled northeast from the Kairi-A platform in 2005 to test the Kairi Horst feature failed to find the Angostura Sandstone. In 2007, a second well from Kairi-B confirmed the presence of both oil and gas in the Horst block, encountering approximately 180 m of gross gas and 30 m of gross oil in the Angostura Sandstone. Pressures measured in the well, as well as different fluid contacts, show that the Kairi Horst is in a separate reservoir compartment from the other parts of the field. The well was completed as an oil producer, but later converted to a gas injector to support a horizontal oil producer drilled in 2011, which had gas breakthrough within half a year. Both wells have produced since 2014 at high GOR and are currently producing mainly gas.

Dynamic data show larger GIIP than estimated from mapping of OBN seismic data and this is likely due to connection to the Olistostrome (Figure 80). Low and Best estimate Resource estimates are based on DCA and reservoir simulation respectively (Table 56).

Figure 80: Hydrocarbon Pore Thickness Map of Olistostrome above Kairi and Horst Fields



Source: BHP Petroleum

Recovery Estimates for AP3, Aripo, Kari, Canteen and Horst

Reserves are attributed to the AP3, Aripo, Kari, Canteen and Horst fields. Estimates of recoverable volumes shown in Table 56 form the basis for the Reserves estimates.

Table 56: Estimates of Initially In Place and Recoverable Volumes for Angostura Projects

Commodity	Field	Initially in Place		Ultimate Recovery	
		Low	Best	Low	Best
Gas (Bscf)	AP3	560	650	459	544
	Aripo	505	518	386	406
	Kari	478	531	331	372
	Canteen	80	95	29	35
	Horst	240	280	181	217
	Block 2(c)	**1,863**	**2,074**	**1,387**	**1,574**
Liquids (MMBbl)	Kari	-	223	58.2	58.8
	Canteen	-	81	24.8	25.0
	Horst	-	9	0.7	0.7
	Condensate	-	-	0.7	0.8
	Block 2(c)	**-**	**313**	**84.4**	**85.3**

Note:

1. Volumes exclude estimates of fuel; no low estimates of oil initially in place are available.

Contingent Resources in the greater Angostura complex within Block 2(c) comprise gas in the Canteen North area (discovered by the Canteen North exploration well in 2011), the Howler area (discovered by the Howler exploration well in 2003), the Nariva age sands (gas discovered by the ANG-NOP-02 well in 2016) and additional gas production from the Canteen, Kairi, Aripo and Horst fields attributed to lowering field abandonment pressure below that currently assumed for the Reserves case.

Canteen North (Block 2(c))

Canteen North was discovered in 2011 north of the oil-bearing Canteen field. Gas was encountered in well-developed Olistostrome sands with a GWC in the upper Angostura thin beds. The thin beds are interpreted as a transgressive phase of the Angostura Sandstone. The majority of GIIP is in the Olistostrome sands (Table 57). Based on regional analogues and weak aquifer drive, ultimate recovery is estimated at 62 Bscf (65% recovery factor). Canteen North is one of the development opportunities in the area when gas ullage becomes available.

Table 57: Best Estimate Reservoir Properties and GIIP for Canteen North

Field / Reservoir	NTG (v/v)	Porosity (v/v)	Water Saturation (v/v)	GIIP (Bscf)
Olistostrome/thin beds	0.3	0.20	0.40	77
Angostura	0.7	0.18	0.22	19

Howler Field (Block 2(c))

The Howler-1 discovery well was drilled in Block 2(c) south of the Angostura Development Area and encountered hydrocarbons in the Naparima Hill carbonate reservoir, flowing gas during a drill-stem test (DST). After declaration of commerciality, the Howler area has been assimilated into Block 2(c).

The presence of matrix porosity with enhanced permeability from fractures is the main uncertainty and it is believed that an additional appraisal well will be required.

GIIP (Table 58) and recoverable gas from the Naparima Hill Formation have been estimated probabilistically. The base case assumes effective gas reservoir to be found down to 500 m below the end-of-thrust (ET) unconformity and the gas water contact (2,545 mss) at the intersection of the Howler gas gradient and Kairi-1 water gradient. The recovery factor (75%) assumes primary depletion through a network of natural fractures enhanced with compression. Analog fields, which produce from fractured and low porosity reservoirs, indicate a wide variation in well quality and recovery per well. Recovery per well ranges from 25 to 80 Bscf.

Table 58: Best Estimate Reservoir Properties and GIIP for Howler Field

Field / Reservoir	NTG (v/v)	Porosity (v/v)	Water Saturation (v/v)	Permeability (mD)	GIIP (Bscf)
Naparima Hill	0.85	0.15	0.65	10	364

Significant uncertainty requires further study prior to drilling any additional appraisal wells. Recoverable volumes are in Contingent Resources and classified as Not Viable as development is uneconomic at prevailing costs and gas prices.

Delaware Field (Block 3(a))

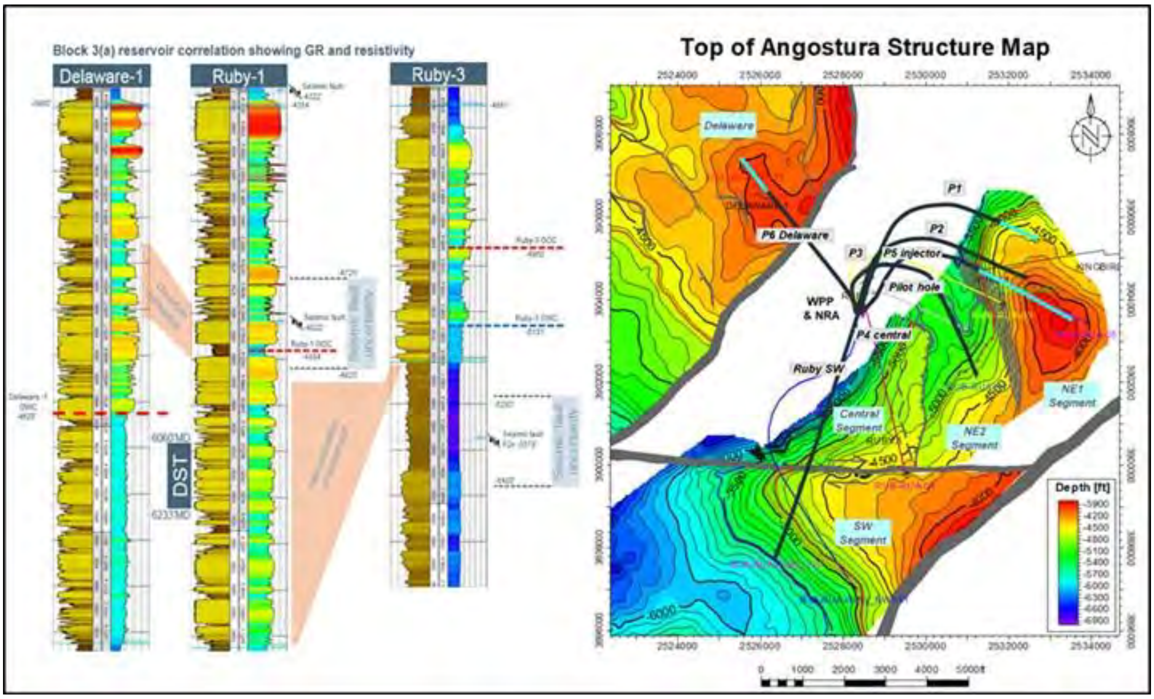
The Delaware-1 well was drilled in 2003 at the crest of the Delaware thrust sheet, which dips to the NNW (Figure 81), discovering gas. One deviated gas producer has been drilled. Estimates of recoverable volumes based on reservoir simulation are shown in Table 59.

Ruby Field (Block 3(a))

The Ruby-1 exploration (2006) and Ruby- 3 appraisal (2016) wells found oil and gas in commercial quantities. However, the Ruby-3 well found an oil-water contact and gas-oil contact shallower than the oil-down-to and gas-oil contact in the initial Ruby-1 well, indicating compartmentalization. Reservoir sand properties are good, with porosity ranging from 12 to 23% (average about 15%) and permeability ranging from tens of milli-Darcies to over 5 Darcy (average around 240 mD). The NTG ranges from 50% to 75% with average about 67%.

Development wells were drilled in 2020 and 2021. The development plan involves four horizontal wells with an injector for pressure maintenance, later followed by gas cap blow down when ullage for sales gas becomes available. Long horizontal reservoir sections (~600 m) are drilled with an orientation designed to maximize contact with stratigraphy and mitigate potential compartmentalization risk.

Figure 81: Type Logs and Structure of Delaware and Ruby Fields



Source: BHP Petroleum

The pilot development well into the NE2 segment drilled in 2021 delivered unexpected results, encountering the top Angostura 120 m deeper than prognosed, with a thinner sand and FWL shallower than the lowest known hydrocarbon depth in the NE1 segment intersected by Ruby-1. The exploration well into the SW segment encountered the Angostura sandstone deeper than prognosed and water bearing. Estimates of ultimate recovery (Table 59) are based on reservoir simulation utilising the OBN seismic, results of the development wells and initial production performance.

Table 59: Estimates of Gross Ultimate Recovery for Delaware and Ruby Fields

Field/Fluid	Low Estimate			Best Estimate		
	HCIIP	Ultimate Recovery	RF (%)	HCIIP	Ultimate Recovery	RF (%)
Ruby oil (MMBbl)	18.5	3.2	17	25.9	4.1	16
Ruby gas (Bscf)	64.6	17.6	27	101.1	33.9	34
Delaware gas (Bscf)	56.3	23.4	42	66.3	29.9	45

8.1.2 Field Development and Production Profiles

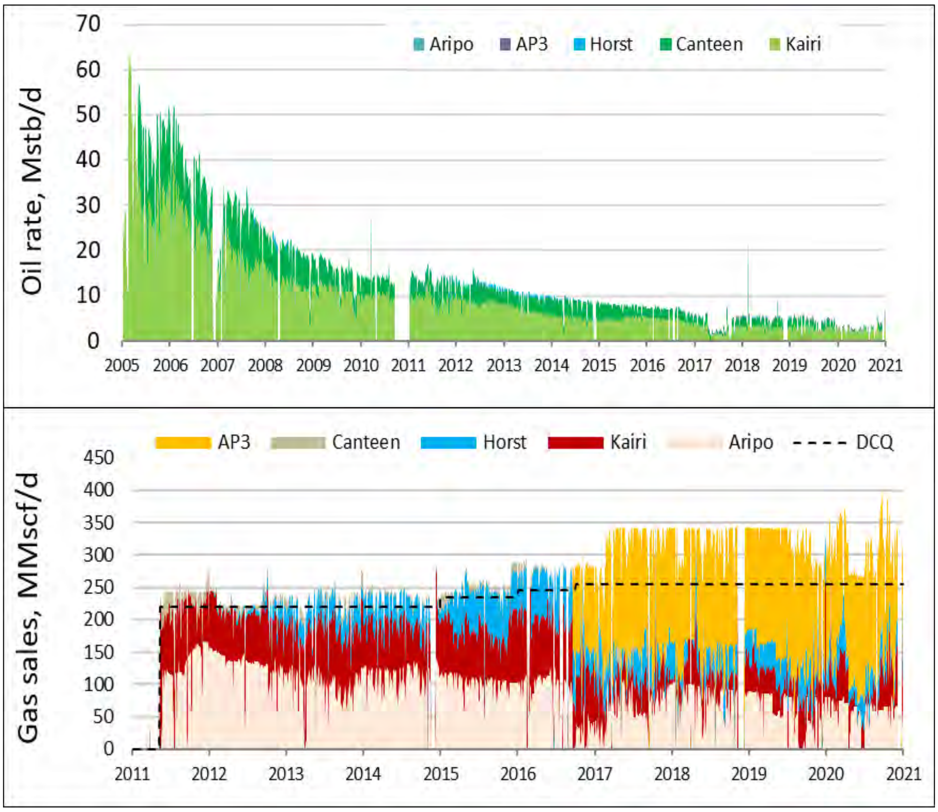
Development of the Angostura oil (Kairi, Canteen and Horst) was sanctioned in February 2003 and drilling began in October 2003, with oil production starting in January 2005 from Kairi. The oil development utilizes horizontal and highly deviated producing wells and deviated gas injection wells, drilled from three fixed wellhead platforms. Produced gas is re-injection into the gas caps for pressure maintenance. In late life a gas cap blow down is planned. The wells produce to a fixed central production platform (CPP) that is bridge connected to one of the wellhead platforms. The central facility hosts living quarters, gas compression equipment for re-injection, and the production facilities necessary to deliver stabilized crude to onshore storage facilities at Galeota Point on the southeast coast of Trinidad. Oil is exported via a catenary anchor leg mooring (CALM) buoy and tanker loadings. Produced gas, less fuel requirements, is re-injected. Produced water is treated and discharged into the sea.

In August 2008, the Angostura Gas Project (AGP) was sanctioned. The development comprises three dedicated gas wells Aripo and provides additional facilities on a new gas export platform (GEP) necessary to produce, process, and deliver natural gas from the gas caps of Kairi, Canteen, Horst and Aripo to the Natural Gas Company of Trinidad and Tobago (NGC) for the domestic market. Under the sales agreement, NGC takes delivery of the gas at an offshore sales delivery point at the GEP. The gas export pipelines, export risers and associated infrastructure are owned, operated, and maintained by NGC. Development of AP3 was sanctioned in 2014 and consisted of 3 subsea gas wells tied back to GEP.

The fields are believed to have limited aquifer support. Pressure data acquired after production commenced indicate communication through the aquifer in the Greater Angostura structure. Faults appear to have low sealing capacity and although compartmentalization causes baffling to flow, communication across faults occurs with differential pressure depletion.

As of June 2021, 31 development wells have been drilled in Block 2(c): 17 horizontal or highly deviated oil wells and eight deviated gas injection wells in Kairi, Canteen and Horst fields, and six dedicated gas producers in Aripo and AP3. Current oil production is ~3,500 bopd coming mainly from Kairi and Canteen. The AP3 and Aripo fields are currently producing the bulk of the total gas sales of ~340 MMscfd (Figure 82), with Horst, Kairi and Canteen fields contributing the remaining sales gas. The combined complex has produced an estimated 80 MMBbl of oil through June 2021 and a total of 967 Bscf of natural gas has been sold.

Figure 82: Historical Production from Greater Angostura Complex



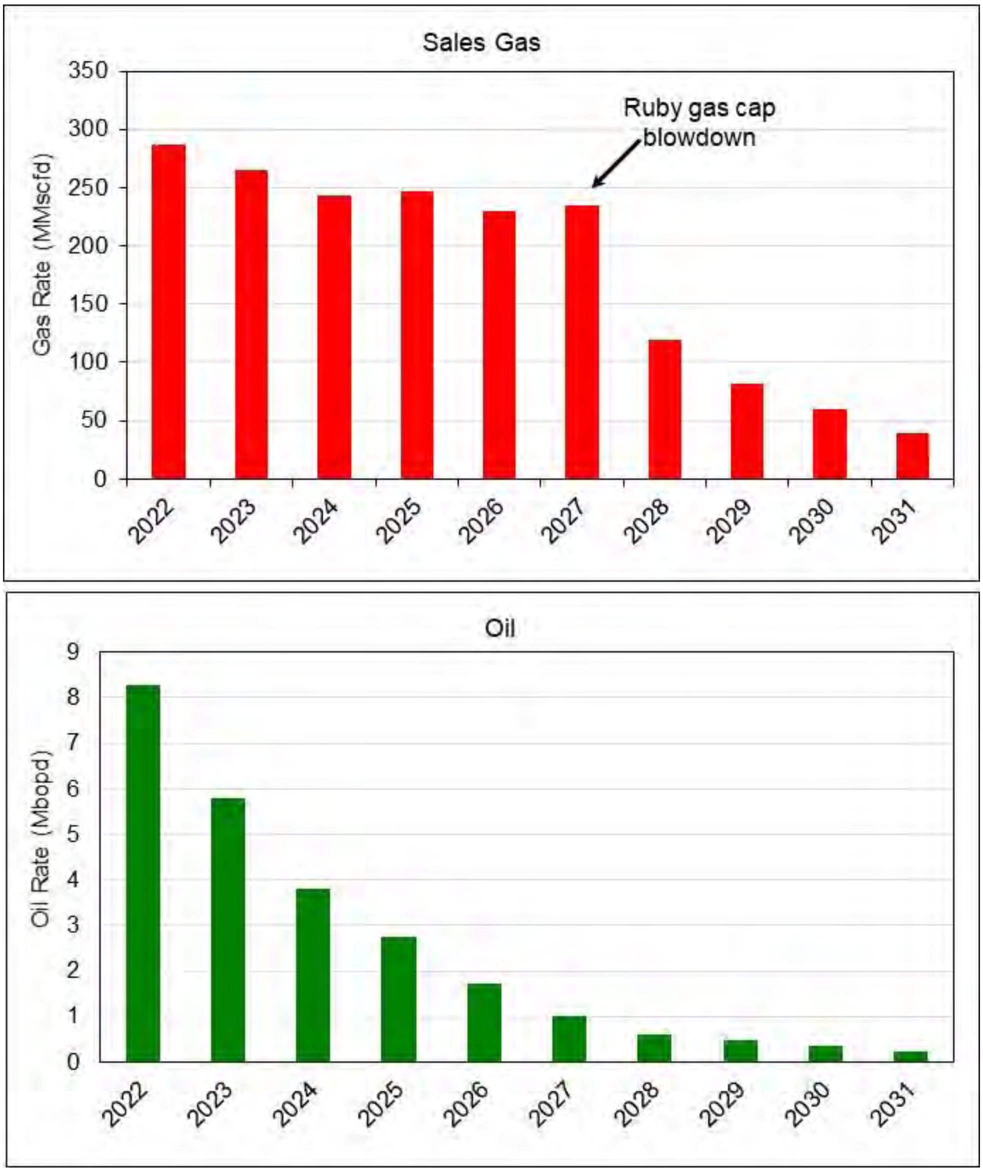
Source: BHP Petroleum

The Ruby/Delaware development of 2020 comprises six wells; four horizontal oil producers and one horizontal gas injection well in Ruby and one deviated gas producer in Delaware. Wells are drilled from a single, unmanned wellhead protector platform (WPP) tied back to the existing Block 2(c) processing facilities (CPP) via 3 flowlines: a production flowline from WPP to CPP for Ruby, an injection flowline from CPP to WPP and a production flowline from WPP to GEP for Delaware. Produced gas will be re-injected in Block 3(a) or exported as sales gas. Metering and allocation instrumentation have been installed on the CPP to distinguish new production from Block 3(a) from existing production in Block 2(c).

The nominal capacity of the processing facilities on the CPP is 100 Mbopd with a gas-handling limit of 350 MMscfd. The expected maximum current daily production rate from the field is ~6 Mbopd and 340 MMscfd of gas. All the gas that is not used for sales, fuel and flare is re-injected into the eight gas injection wells in Canteen, Kairi and Ruby. Current daily injection target is approximately 160 MMscfd.

Figure 83 shows overall production profiles for Block 2(c) (AP3, Aripo, Horst, Canteen, Kairi fields) and Block 3(a) (Ruby and Delaware fields) combined.

Figure 83: Production Forecasts for Block 2(c) and Block 3(a) Combined



Source: GaffneyCline modified from BHP Petroleum data

8.1.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

For both Block 2(c) and Block 3(a), the 1P and 2P Reserves CAPEX comprises of risk reduction and improvement costs, but no significant facilities expenditure. The BHP Petroleum CAPEX estimates have been reviewed and appear to be credible, and have been adopted unchanged.

Gross CAPEX for development of the Reserves case is estimated to be US$68 MM.

The OPEX for the 1P and 2P Reserves is broken down into fixed operating overhead costs, lifting costs and processing and storage. The OPEX estimates have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted to account for changes in the variable OPEX components of the total OPEX resulting from differences between BHP Petroleum's production profiles and GaffneyCline's profiles, and allocation of the total OPEX adjusted between 2(c) and 3(a) based on the relative production rates.

8.1.4 Resources Estimates

Reserves are attributed to the AP3, Aripo, Kairi, Canteen, Horst, Ruby and Delaware fields. Coupled simulation models are used to forecast performance of the Canteen, Kairi, Horst, Aripo and AP3 fields together. The forecast assumption is that 255 MMscfd will be produced from Block 2(c) leaving an ullage of 85 MMscfd for gas from Block 3(a) Ruby/Delaware fields.

Contingent Resources in Block 2(c) include volumes that are associated with the Canteen North and Howler discoveries and production associated with the Canteen, Kairi, Horst and Aripo fields at lower abandonment pressure than currently assumed. In 2016, a gas discovery was made in the Nariva age sands during the drilling of the ANG-NOP-02 well. All these Contingent Resource volumes are classified as Not Viable as no plans exist to mature these development opportunities.

Table 60: Gross 2C Contingent Resources for Block 2(c) as at 31st December 2021

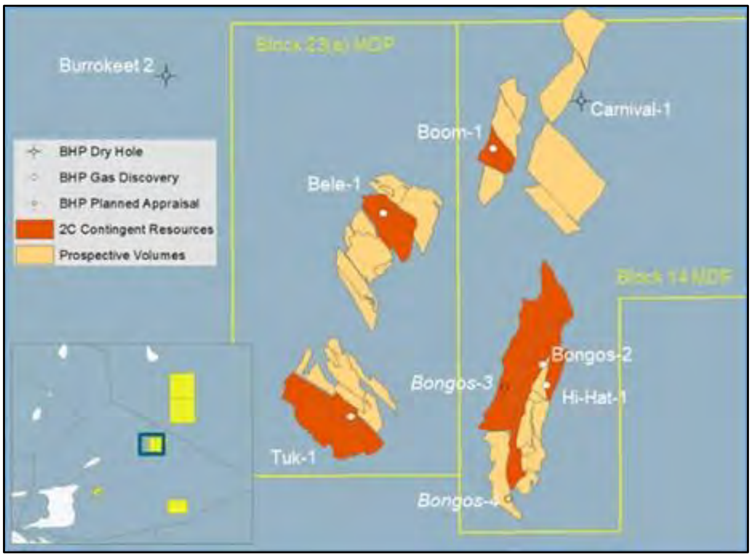
Field	2C Contingent Resources	
	Gas (Bscf)	Condensate (MMBbl)
Canteen North	62	-
Howler	274	1.6
Nariva	9	-
Lower Abandonment Pressure	25	-
Total	**370**	**1.6**

8.2 Deep Water North – Calypso Development

The Deep Water North area covers Blocks 23(a) and 14 (Figure 84), approximately 170 km northeast of the island of Tobago with a water depth of 2,000 m. BHP Petroleum is the operator and has a 70% working interest with BP as partner. BHP Petroleum drilled seven exploration wells and made five discoveries (Bongos, Bele, Tuk, Hi-Hat, Boom), with the

Burrokeet and Carnival wells being unsuccessful. The discoveries are expected to be developed in a single development referred to as Calypso.

Figure 84: Location Map of Deep Water North Calypso Development



Source: BHP Petroleum

8.2.1 Field Description

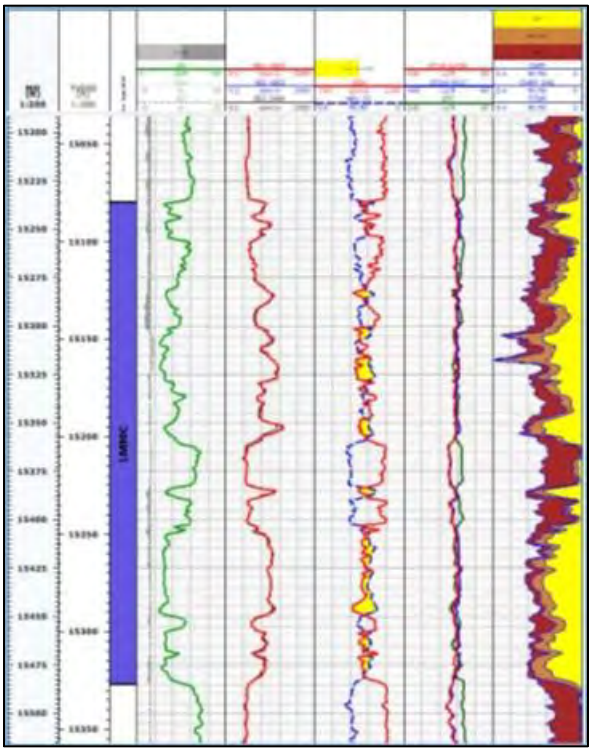
Bongos was discovered in 2018 and contains thermogenic gas in a shallow PO2 and deeper LM90C reservoir. Exploration wells were drilled in 2019 in the Bele, Tuk, Hi-Hat and Boom prospects. Mixed thermogenic and biogenic gas was discovered in Bele and Tuk in the PO15 and PO2 reservoirs, and thermogenic gas was found in the PO2 reservoir in Hi-Hat and the LM97 reservoir in Boom. Two appraisal wells have been drilled in the Bongos field in 2021.

Seismic data were acquired in 2014. A complete suite of wireline logs and comprehensive set of side-wall core data, pressure and fluid samples were acquired in the exploration wells. Whole core data was collected in two side-tracks of the Bele-1 well. A type log for the Bongos LM90 sandstone reservoir is shown in Figure 85.

Following reinterpretation of 2018 reprocessed seismic data and updated petrophysical models, static geomodels were built and used for dynamic simulation to assess resource for Bongos, Bele and Tuk. Three separate models were built (Bongos PO2, Bongos LM90C and Bele/Tuk PO15/PO2).

Gaffney Cline

Figure 85: Composite Type Logs Bongos Field (Well Bongos 2)



Source: BHP Petroleum.

The Bongos PO2 sands are interpreted to be stacked amalgamated sheet sands, likely deposited toward the margin of a channelized lobe sequence. The lower portion of the Bongos LM90C is interpreted to be stacked amalgamated sands, likely deposited toward the margin of a channelized lobe sequence. In the upper portion, the LM90C sands are interpreted to be stacked axial/off-axial channel fill sands capped by a series of levee deposits, and finally, by a mass transport complex (MTC).

The Bele and Tuk PO15 and PO2 sands are interpreted to be stacked amalgamated sheet sands, likely deposited toward the axial portion of a channelized lobe sequence. The Hi-Hat PO2.250 sand is interpreted to be an internal levee to the PO2.250/200 meandering channel. The lower and upper portions of the Boom LM97 sands are interpreted to be stacked amalgamated sands, likely deposited toward the axial portion of a channelized lobe sequence, that have been modified locally by an overlying MTC.

The data used for the integrated reservoir interpretation of the area entailed all available logs and the 3D seismic reprocessed 2018 full stack volume including six well penetrations, detailed well correlations, reservoir facies from log and core, and pressure information for both PO2 and LM90C reservoir sections. Seismic interpretation was used to determine the extent of hydrocarbon traps, faults and compartmentalization, gas water contacts (from combination of structural contour maps and evidence of seismic amplitude conformance), gross rock volume, geomorphology of the gross depositional environment and the approximate extent and thickness of the main reservoirs.

Average reservoir properties show high porosity of 25% or more, while permeability is variable between reservoirs and fields, with some reservoirs having low values (20 to 30 mD) while others have permeability measuring hundreds of milli-Darcies. Net reservoir varies between 30 m and 200 m.

Gas samples as well as water samples were collected during the exploration phase and PVT analysis indicates that the gas encountered in the reservoirs is dry with high methane content ranging from 96% to 99% for the shallowest reservoir (Bele PO15 at 3,350 mss) and no H_2S. The Bongos LM90C has a low condensate yield (CGR of 2 Bbl/MMscf). The reservoir pressure ranges from 5,600 psia to 10,000 psia and reservoir temperature from 137°F to 167°F.

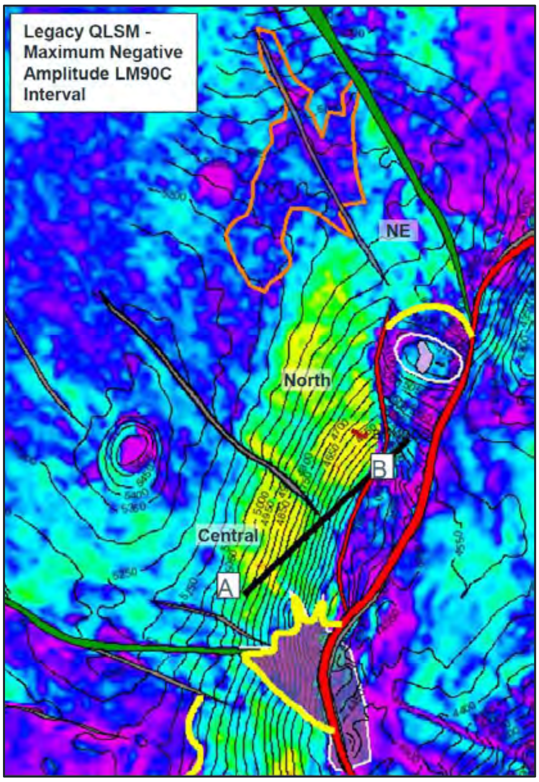
MDT pressures from the Bongos and Boom fields indicate pressure equilibrium at initial conditions in all wells that intersected the LM90C interval. No GWC has been encountered in the wells (GDT is 4,672 mss). The seismic derived GWC from DHI analysis (Figure 86) is 5,160 mss, which corresponds closely to a pressure derived FWL assuming gas pressure in Bongos LM90C and pressures taken in the water bearing LM90C in Boom field (FWL of 5,190 mss). This equates to a gas column of ~610 m. Appraisal well Bongos-3 encountered hydrocarbons approximately 30 m shallower than expected from seismic data and found slightly better reservoir properties.

In the Bongos field, analysis of dip closure, major faults (thrust faults, normal faults) and erosional truncation suggests that three areas of the LM90C reservoir can be distinguished (South, Central, North, and North-East) (Figure 86). However, juxtaposition of formations across faults according to interpretation of fault throw suggest that these three areas can potentially be combined into a single North Segment, considered discovered by the Bongos-2 well. Bongos-4 was drilled in the South segment and encountered hydrocarbons approximately 30 m shallower than expected from seismic data. The seismic amplitude was confirmed by the well although the extent of the anomaly to the south of the well is smaller than the mapped closure.

The 200 and 300/400 zones in the PO2 sand of the Bongos field are not in pressure equilibrium and no GWC has been encountered (GDTs are 3,795 mss and 3,909 mss respectively). The seismic derived GWCs are 3,974 mss and 4,000 mss respectively resulting in gas columns of ~213 m and 120 m. The extent of the interpreted 200 and 300 zone accumulations is bounded by dip closure, stratigraphic truncation, and the major thrust fault. The 200 zone is divided into two segments based on seismic. Based on the seismic derived GWCs, it can be concluded that the aquifers from LM90C and PO2 are not connected (2,500 psi pressure offset) in the Bongos field.

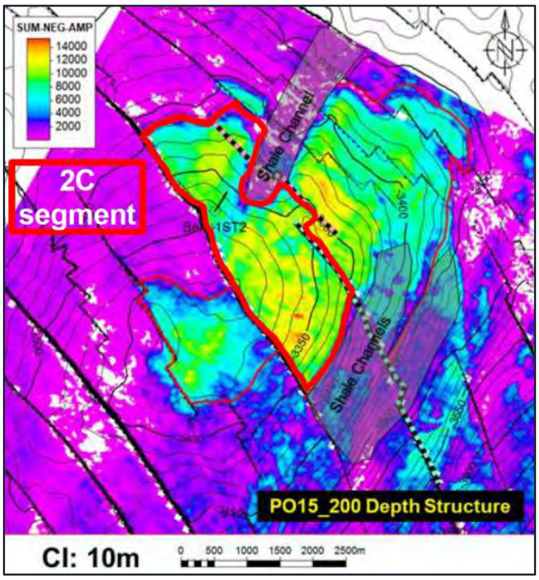
In the Bele field, the three gas bearing zones in the PO15 sand are in pressure equilibrium at initial conditions. The main compartment penetrated by well Bele-1 is bounded by faults, a shale channel and the GWC evidenced by seismic conformance (Figure 87). A GWC has been encountered in Bele-1 well in the PO2 sand, zone 300 at 3,776 mss and corresponds well with the MDT derived FWL. The 100, 200 and 300 zones in the PO2 sand are in pressure equilibrium but the water bearing zone 400 is not in pressure equilibrium and MDT pressures show a 25 psi offset. The main compartment is bounded by sealing faults and the GWC.

Figure 86: Bongos LM90C Regions



Source: BHP Petroleum

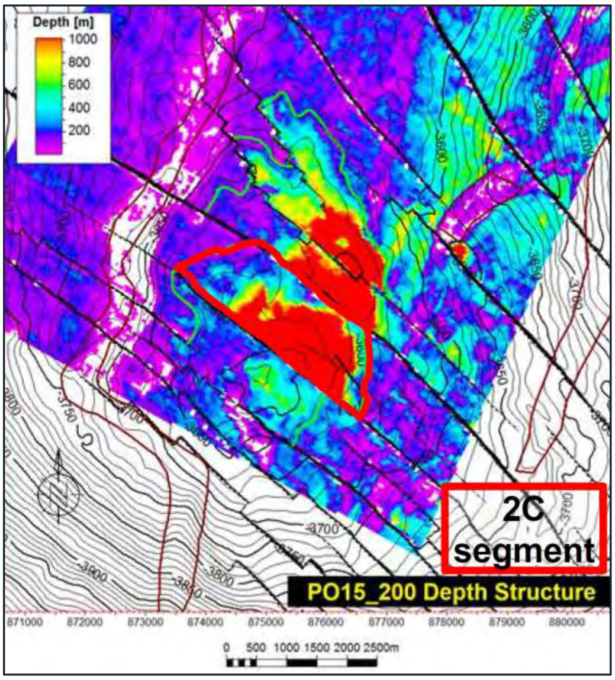
Figure 87: Bele PO15 Discovered Polygon



Source: BHP Petroleum

In the Tuk field a GWC has been encountered in the PO15 sand zone 200 at 3,600 mss and this corresponds well with the MDT derived FWL. MDT pressures in the 300 zone indicate a slight offset of 3 psi from the 200 zone and it is likely, but not certain, that they are in pressure equilibrium. Based on DHI analysis, two compartments are distinguished, bounded by the GWC and faults. Only the southern block has been penetrated by a well (discovered), whereas the northern block is prospective (Figure 88).

Figure 88: Tuk PO15 Discovered Polygon

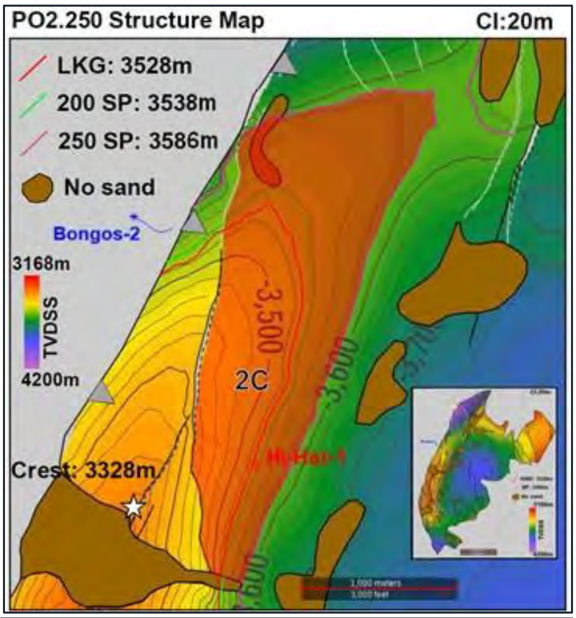


Source: BHP Petroleum

The PO2.200 and PO2.300 are both gas bearing sands. Thin laminated sands were found in the upper section of the 200 zone. The PO2.400 is interpreted as a gas bearing shaly sand with a GWC at 4,238 mss. MDT pressures indicate that zone 200 and 300 are in pressure equilibrium, whereas zone 400 shows a 40 psi offset when a seismic derived GWC is assumed for the 200/300 zone. The southern and northern area are separated by a sealing fault (Figure 88). The southern segment is interpreted to have a shared GWC across faults based on DHI analysis.

The Hi-Hat structure is a stratigraphic trap created by overlying younger channels, limited to the west by the major thrust fault separating Bongos from Hi-Hat (Figure 89), and with a down-dip limit defined as the structural spill point of the PO2.250 sand. Gas was found to the base of the PO2.250 sand and PO2.300 was fully water bearing. A FWL of 3,528 mss is inferred from MDT pressures, which is the same depth as the base of the PO2.250 sand. However, the GWC in the PO2.250 sand is interpreted to be controlled by the present-day structural spill point of the northern Hi-Hat PO2.250 segment (3,586 mss).

Figure 89: Hi-Hat PO2.250 Structure

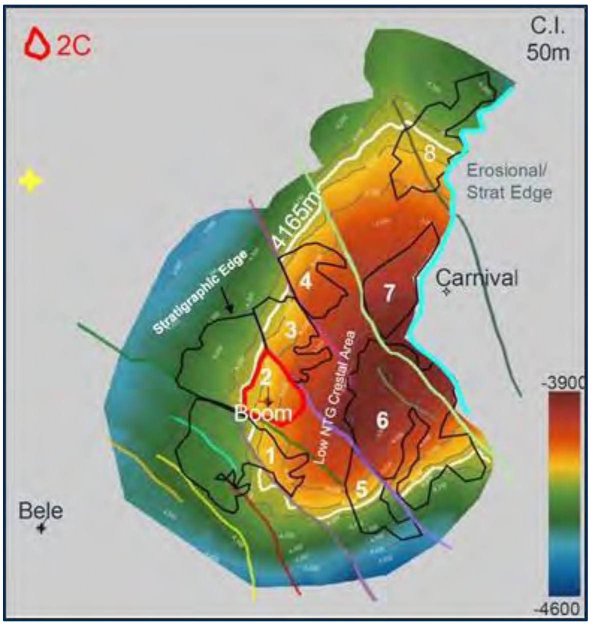


Source: BHP Petroleum

A GWC was encountered in Boom-1 well close to the base of the LM97 lower sand at 4,165 mss. MDT pressure indicate that the upper and lower sand lobes are in pressure equilibrium. One valid pressure was taken in the water at the base of LM97 lower sand, supporting the observed GWC. Seismic interpretation shows that the Boom structure is compartmentalised, bounded by faults, the GWC, a stratigraphic edge, a low NTG crestal area due to stratigraphic pinch-out, and an erosional/stratigraphic edge in the NE (LM97 not present in Carnival well). E-W connectivity is unlikely.

GIIP has been estimated using static models (Bongos, Bele and Tuk) or probabilistic (GeoX software) models (Boom and Hi-Hat) built from the comprehensive seismic and drilling derived dataset acquired to date. Best estimate estimates of GIIP for the compartments and reservoirs that have been intersected by exploration/appraisal wells and are therefore considered discovered are shown in Table 62.

Figure 90: Boom LM97 Structure



Source: BHP Petroleum

8.2.2 Field Development Plan

A semi-submersible FPU centrally located between the Bele, Bongos and Tuk fields, with a production capacity of 800 MMscfd gas, 4 Mbwpd of produced water and arrival pressure of 600 psi is one of the development concepts under consideration and has been used to estimate recoverable volumes. Wells will be produced via a daisy chain to the FPU. Gas export options including a pipeline to shore and selling to the Trinidad and Tobago domestic market and to LNG export are being considered.

The FPU development concept assumes 16 wells in the Bongos LM90C, Bele and Tuk reservoirs with single zone completions. Ten of these development wells are in penetrated and discovered fault blocks (Contingent Resources Unclarified) and six wells in adjacent un-penetrated blocks (Prospective Resources). Currently the discovered Bongos PO2, Boom and Hi-Hat reservoirs are excluded from the FPU development concept. BHP Petroleum is currently anticipating a possible start-up date for Calypso area development in the late 2020s.

8.2.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

Overall CAPEX is subdivided into each of the main development items comprising wells, facilities and pipelines. Each of these CAPEX elements has been reviewed and appears credible, based on GaffneyCline's experience of comparable developments. CAPEX is shown in Table 61.

Table 61: Calypso Gross CAPEX Estimates for Contingent Resources

Item	CAPEX (US$MM)
Appraisal Wells	145
Development Wells	1,527
Facilities	2,461
Pipelines	548
Total	**4,681**

The overall annual OPEX estimate for the development has been reviewed by GaffneyCline, taking into consideration the planned development. The OPEX profiles have been adjusted in the Contingent case to account for changes in the expected variable OPEX components of the overall OPEX resulting from differences between the BHP Petroleum production profiles compared with the GaffneyCline profiles.

8.2.4 Resources Estimates

Recoverable volumes for discovered and prospective reservoirs selected for development in Bongos, Bele and Tuk (Table 62) were estimated based on dynamic simulation models. For Hi-Hat and Boom, which are not currently included in the FPU concept, recovery factors were derived using type curves from Bele and Bongos, adjusted for permeability and pressure differences.

Estimated recovery factors ranging from 44% to 71% are comparable to those of fields with analogous reservoir connectivity and moderate aquifer support. The recovery factor in Bele PO15 (44%) is lower than the other fields because only one well is assumed for a connected GIIP of 437 Bscf. The ultimate recovery per well is in the range 100 to 600 Bscf, except for the development well in Hi-Hat (18 Bscf).

The following Resources are attributed:

- Gas Contingent Resources are attributed to the discovered reservoirs that are included in the development and will be penetrated by at least one development well. Gross 2C Contingent Resources: 3,692 Bscf of gas (Development Unclarified).
- Gas Contingent Resources are attributed to the discovered reservoirs that are not currently included in the development. Gross 2C Contingent Resources: 418 Bscf of gas (Development Not Viable).
- Gas Prospective Resources are attributed to low risk prospects that are provisionally included in the development concept. Gross 2U Prospective Resources: 1,024 Bscf of gas.

Besides the “high graded” Prospective Resources that are included in the provisional development plan, numerous other prospective targets have been identified in the area which offer upside potential.

Following the drilling of the two appraisal wells in 2021 volumes in the Bongos South block are now considered discovered and preliminary results of the appraisal wells have been included in the estimation of their Contingent Resources.

Further technical evaluations and feasibility studies are planned to mature the Calypso development.

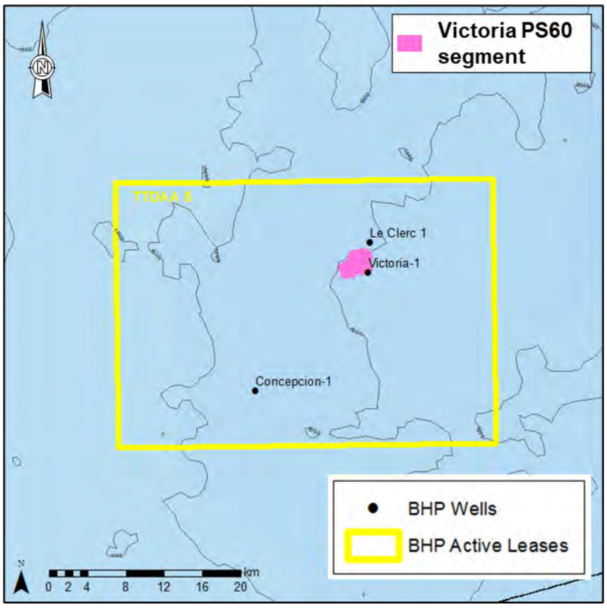
Table 62: GIIP and Estimates of Recoverable Volumes for Calypso Reservoirs as at 31st December 2021

Field / Reservoir	Block	GIIP (Bscf)	No. of Development Wells (Base Case)	Gross Recoverable Gas (Bscf)	Classification
Bongos PO2	N	460	-	281	Contingent Not Viable
Bongos LM90C	C, N, NE	2,543	3	1,761	Contingent Unclarified
	S	966	1	601	Contingent Unclarified
Bele PO15	Main	437	1	193	Contingent Unclarified
	NE	455	1	194	Prospective
Bele PO2	Main	306	1	176	Contingent Unclarified
	NE	174	1	89	Prospective
	SW (D)	366	1	315	Prospective
	SW (F)	213	1	148	Prospective
Tuk PO15	S	124	1	86	Contingent Unclarified
Tuk PO2	S	1,228	3	875	Contingent Unclarified
	N	471	2	278	Prospective
Hi-Hat PO2		29	-	18	Contingent Not Viable
Boom LM97	2	188	-	119	Contingent Not Viable
Base Case Total (Contingent)			**10**	**3,692**	**Contingent Unclarified**
Base Case Total (Prospective)			**6**	**1,024**	**Prospective**
Other Contingent Total			**-**	**418**	**Contingent Not Viable**

8.3 Deep Water South – Magellan

The Deep-Water South area, also called Magellan, covers Block TTDAA 5. BHP Petroleum signed a PSC in 2013 for exploration in TTDAA5, approximately 200 km east of the island of Trinidad with water depth of 1,800 m (Figure 91). BHP Petroleum is operator and has a 65% working interest with Shell as partner (BG farmed-in in 2014 and BG was later acquired by Shell). BHP Petroleum made two discoveries with exploration wells Victoria-1 and LeClerc-1, whereas the Concepcion-1 exploration well was unsuccessful.

Figure 91: Location Map of the Victoria and LeClerc Discoveries, TTDAA Block 5



Source: BHP Petroleum

8.3.1 Field Description

LeClerc was discovered in 2016 and contains dry biogenic gas in the Pliocene PO20 and PO2 reservoirs. In 2018, an exploration well was drilled in Victoria prospect and encountered dry biogenic gas in the Pleistocene PS60 reservoir and found low residual gas saturations in the deeper PS54, PS57 and PO94 sands. The Pliocene is characterized mostly by deep water turbidites and basin floor fan systems, while the Pleistocene comprises leveed-channel and channelized lobe complexes

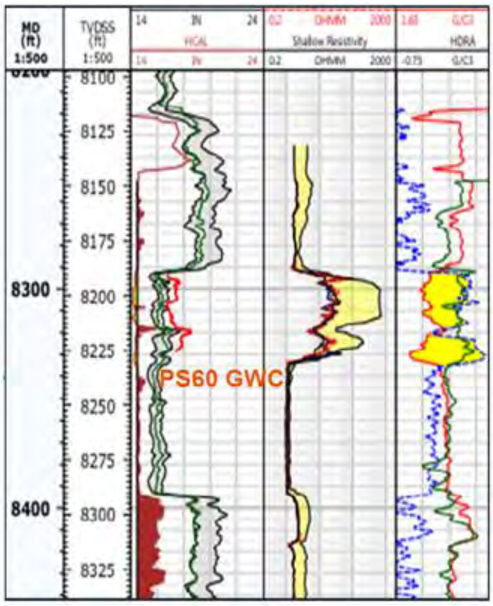
A complete suite of wireline logs, MDT pressure data and fluid samples were acquired in the exploration wells. Side-wall core data were acquired in LeClerc-1 and whole core data was collected in Victoria-1. BHP Petroleum acquired a proprietary narrow-azimuth 3D seismic survey over the Trinidad and Tobago TTDAA-5 and TTDAA-6 licences area in 2014 and a Pre-Stack Depth Migration (PSDM) was completed in 2015. Subsequent reprocessing of the data in 2017 provided an improved velocity model and imaging. Coloured-inversion (CI) and fluid volumes were produced from the 2017 PSDM to aid in structural interpretation and predict the presence of hydrocarbons.

Interpretation from seismic data as well as the GWC penetrated in the Victoria-1 well form the basis of the segment definition and GIIP estimates (2017 reprocessed data was not used for resource estimates). Top and base horizons for the reservoirs were mapped on the reflectivity and CI volumes and were used to define the segment definition of the reservoirs. Amplitude extractions performed on the CI and fluid volumes were used to determine the sand extents and the GWC's for each reservoir.

Type logs for the PS60 reservoir (Figure 92), PO20 and PO2 (Figure 93) show the sands to be blocky and good quality. Average reservoir properties are good, with porosities of 20 to 30% or more and permeability up to several hundred milli-Darcies.

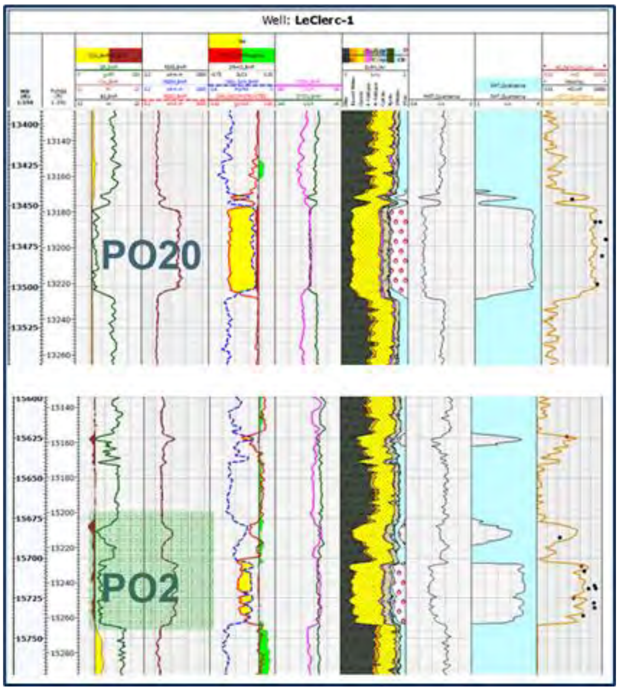
The Victoria PS60 reservoir is at a depth of ~2,500 mss, with pressure of ~3,790 psi and temperature of ~73 degF. The LeClerc PO20 and PO2 reservoirs are deeper, at ~4,020 mss and ~4,640 mss respectively, with pressures of ~7,410 and 7,980 psi and temperatures of ~149 and ~173 degF.

Figure 92: Composite Type Log Victoria PS60



Source: BHP Petroleum

Figure 93: Composite Type Log of LeClerc PO20 and PO2 Reservoirs

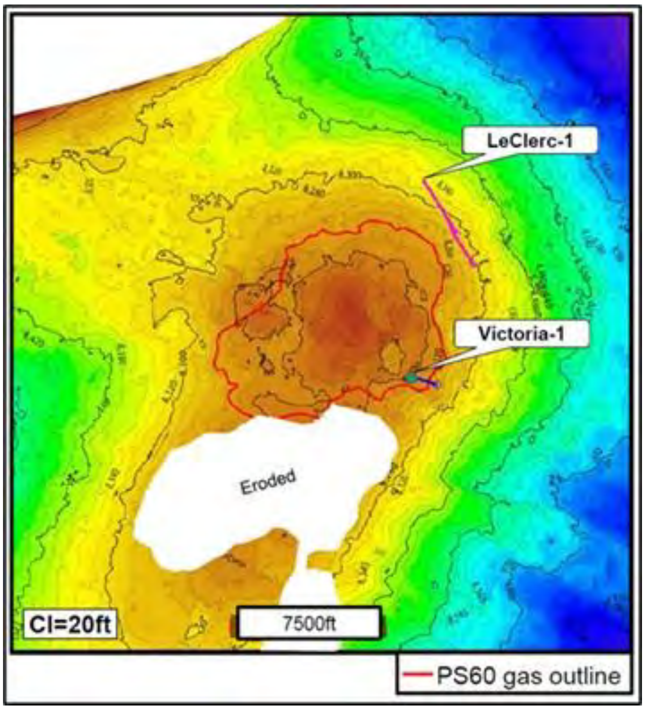


Source: BHP Petroleum

Multiple gas samples (both wells) and water samples (Victoria-1) were collected, and PVT analysis indicates that the gas encountered in the reservoirs is dry with high methane content of 99% and no H2S. Water salinity in Victoria PS60 is 34,000 ppm.

The Victoria-1 well penetrated the gas water contact in the PS60 at a depth 2,508 mss, a depth supported by the interpretation of MDT pressures. The gross rock volume is defined by the structural closure of the gas water contact and top surface of the PS60 as defined by the seismic interpretation (Figure 94). The contact conforms to structure except for the southeast quadrant which is interpreted to be eroded and the northwest quadrant which is interpreted to be a stratigraphic edge.

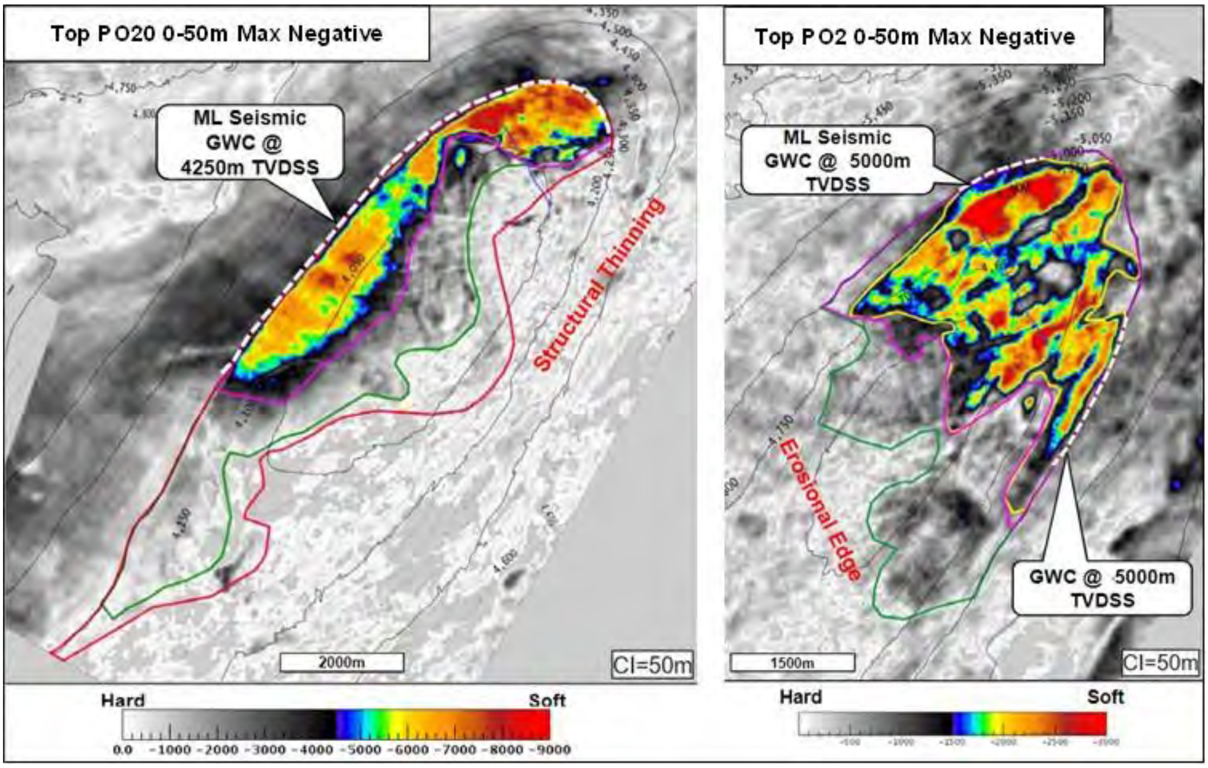
Figure 94: Victoria PS60 Top Structure and Seismic Amplitude Map



Source: BHP Petroleum

In the LeClerc field, the PO20 and PO2 sands were found fully gas bearing and no GWC has been encountered. However, the structure is well imaged and both reservoirs have distinct, depth conforming seismic amplitude shutoffs (Figure 95), which give an indication of the GWC.

Figure 95: LeClerc PO20 and PO2 Seismic Amplitude Maps



Source: BHP Petroleum

8.3.2 Conceptual Field Development Plan

Current development concepts under consideration involve subsea wells at LeClerc and Victoria tied back to a semi-submersible host in deep water with export line to shore, or tied back to a host platform or directly to shore (~250 km). Currently, discovered volumes are below the threshold for economic development and are classified as Development Not Viable.

8.3.3 Resources Estimates

Based on the seismic interpretations of the basin, it is likely that the aquifers are active and large. Recovery factors have been estimated using analytical methods on the assumption that the drive mechanism would be a combination of aquifer influx and pressure depletion. This approach takes account of reservoir swept by water encroachment, the trapped residual gas saturation and pressure behind the flood front, abandonment pressure in depleted un-swept gas zones and reservoir connectivity.

Recovery factor ranges from 48% to 59% (Table 63) are reasonable and comparable to the lower end of the range for analogue fields with moderate to strong aquifer support. LeClerc PO2 sand is expected to have a lower connectivity than LeClerc PO20 and Victoria PS60. The Victoria recovery factor is lower than LeClerc PO20 as the PS60 reservoir is much shallower with lower reservoir pressure. Further, a tie-back development will have higher abandonment pressures than deep water development with a stand-alone host.

Total gross gas 2C Contingent Resources (Development Not Viable) of 482 Bscf have been attributed to the discoveries.

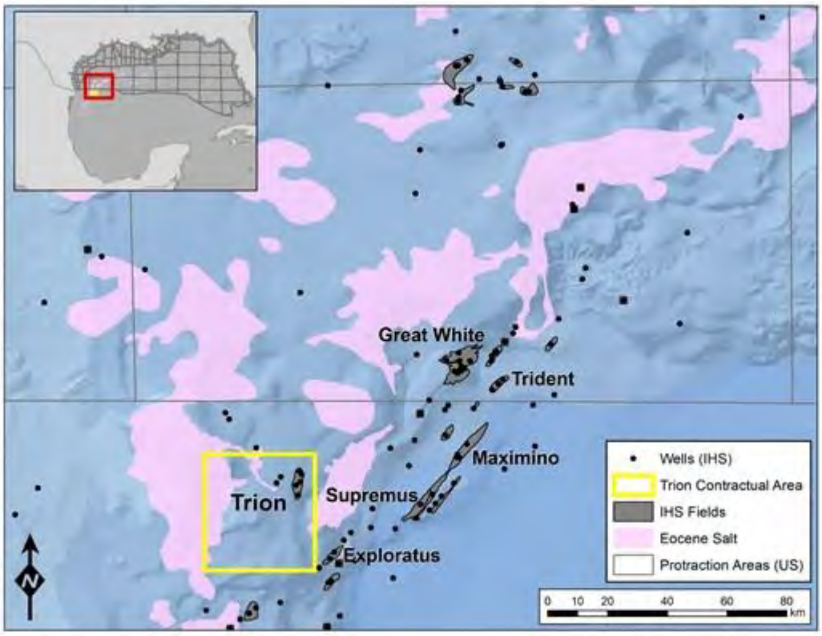
Table 63: Estimated GIIP and Gross 2C Gas Contingent Resources for LeClerc and Victoria as at 31st December 2021

Field / Reservoir	GIIP (Bscf)	Recovery Factor (%)	2C Gas Contingent Resources (Bscf)
LeClerc PO20	391	59	231
LeClerc PO2	194	48	94
Victoria PS60	313	50	157
Magellan Total	**898**		**482**

9 BHP Petroleum Mexico

BHP Petroleum holds a 60% participating interest in the Trion Contractual Area located in the deep-water Gulf of Mexico offshore Mexico, and is also the operator. PEMEX Exploration & Production Mexico holds the remaining 40% interest. The initial lease term runs to March 2052 with potential for lease extensions pending government approval.

Figure 96: Location Map of Trion Field



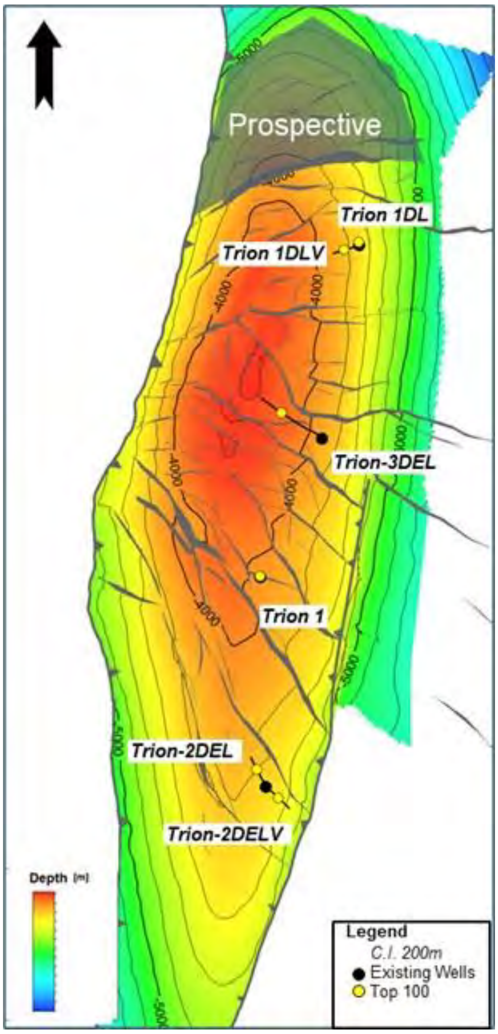
Source: BHP Petroleum

9.1 Trion

9.1.1 Field Background

Trion was discovered by Pemex in 2012 with the Trion -1 exploration well (Figure 97) in water depth of ~2,500 m. Pemex appraised the field with well Trion-1DL and side-track Trion-1DLV. BHP Petroleum appraised the field further with wells Trion-2DEL and side-track Trion-2DELV, and Trion-3DEL. Two Eocene age reservoirs have been delineated; the overlying 100 Fan, which contains the bulk of the oil, and the 350 Fan. The four wells provide good coverage of the field in a north to south direction, but are all located east of the central line, and provide little data on east-west variation in reservoir presence and quality, which is based on interpretation of the 3D seismic data. The majority of the estimated resources are on the east side of the field with limited development expected on the west side.

Figure 97: Depth Structure Map of Top 100 Fan



Source: BHP Petroleum

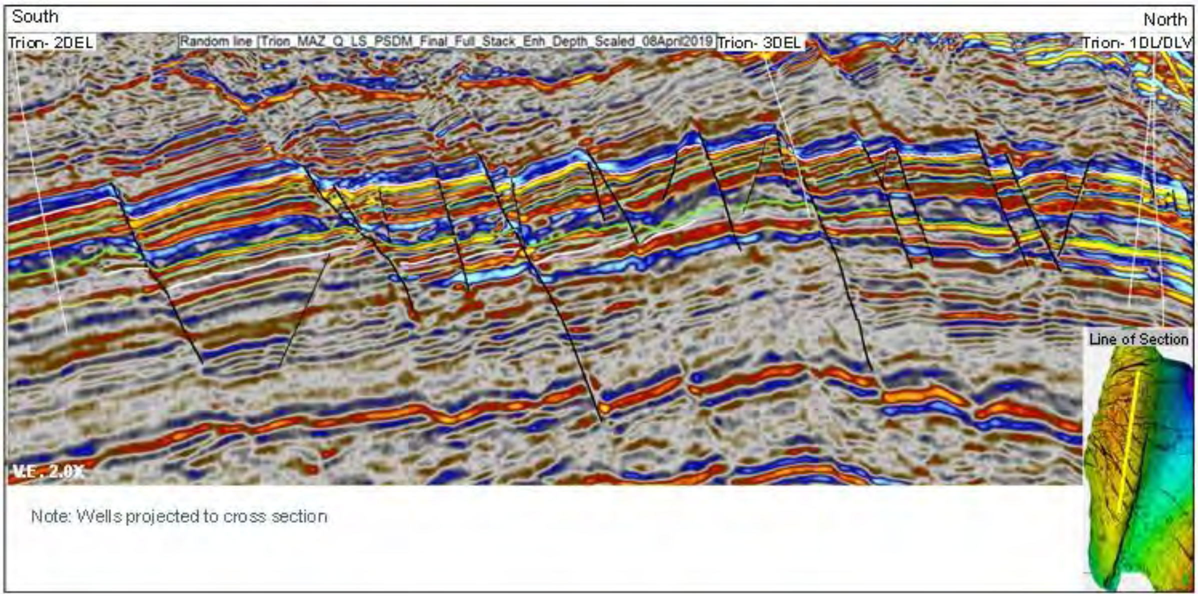
A comprehensive suite of wireline logs has been acquired in all wells. Whole cores were obtained in Trion-1, Trion-1DL and Trion-2DEL/V, and sidewall cores were recovered from Trion-1, Trion-2DEL/V and Trion-3DEL. A DST was carried out in Trion-1DLV, "mini-DSTs" using a dual packer configuration were carried out in Trion-1, and Interval Pressure Transient Testing (IPTT), using a Saturn tool (Saturn 3D Radial Probe) was carried out in Trion-2DEL/V and Trion-3DEL. A comprehensive set of fluid samples has been acquired.

Three dimensional seismic surveys were acquired in 2012 (wide azimuth) and in 2017 (wide and narrow azimuth). A multi-azimuth reprocessing project of these two datasets was undertaken in 2019. In 2020-2021 a 3D ocean bottom node (OBN) survey was acquired, which has greatly enhanced definition in the crest and west of the structure where seismic imaging had previously been poorer due to a shallow anomaly. BHP Petroleum is still in the process of interpreting the OBN dataset and it is likely that the information will lead to refinements of the development plan, although the focus of the development is on the eastern side of the structure where good seismic data existed prior to the OBN.

Seismic and well data have been used to map the Trion structure and seismic attributes have been used to condition the interpretation of the 100 Fan and 350 Fan reservoirs. Each survey has improved the knowledge and understanding of the reservoirs, allowing the distribution of lithology, porosity and fluids within the reservoir interval to be enhanced. The top and base of each of the reservoir units can be seismically mapped and these surfaces are key to the reservoir model.

The Trion discovery is a north-south oriented anticline bounded to the east and west by reverse faults and is mapped as dip closed to the north and south. The anticline formed due to compressional forces and the movement of nearby salt. The structure is internally faulted (Figure 98) and the dominant fault direction is NNW-SSE. Some faults are interpreted to compartmentalise both reservoirs, giving rise to multiple fluid contacts, while others might potentially create baffles to flow.

Figure 98: Seismic Section Showing Reservoir Architecture



Source: BHP Petroleum

BHP Petroleum has identified a prospect (Trion North Prospect) at the northern end of the Trion Field. This is in essence the northern “nose” of the anticline that contains the Trion discovery. It is considered a prospect as the fault that separates it from the field area is large and potentially offsets the 100 Fan and 350 Fan reservoir intervals. The seismic attributes seen in the field are also present in the Trion North Prospect, however, their development is less well defined and the conformance with structure poorer. BHP Petroleum interprets these differences being the effect of velocity issues in this part of the structure.

The 100 Fan is further subdivided into three sandstone units, the upper, middle and lower lobes, separated by shales. The 350 Fan does not have such clear subdivisions. At the crest of the structure, the depth of the 100 Fan is ~3,800 mss and that of the 350 Fan is approximately 3,950 mss.

The reservoirs are interpreted as deepwater sandstones deposited as lobe complexes with a SW – NE trend. Seismic data have been used to condition the distribution of facies and porosity in the static model. The sandstones are thick with average net thickness from well intersections of 77 m for the 100 Fan and 35 m for the 350 Fan. Average well porosities are also high at 29% and 25% for the 100 Fan and 350 Fan respectively and permeabilities are moderate, at 162 and 42 mD (Table 64).

Table 64: Trion Petrophysical Property Averages from Wells

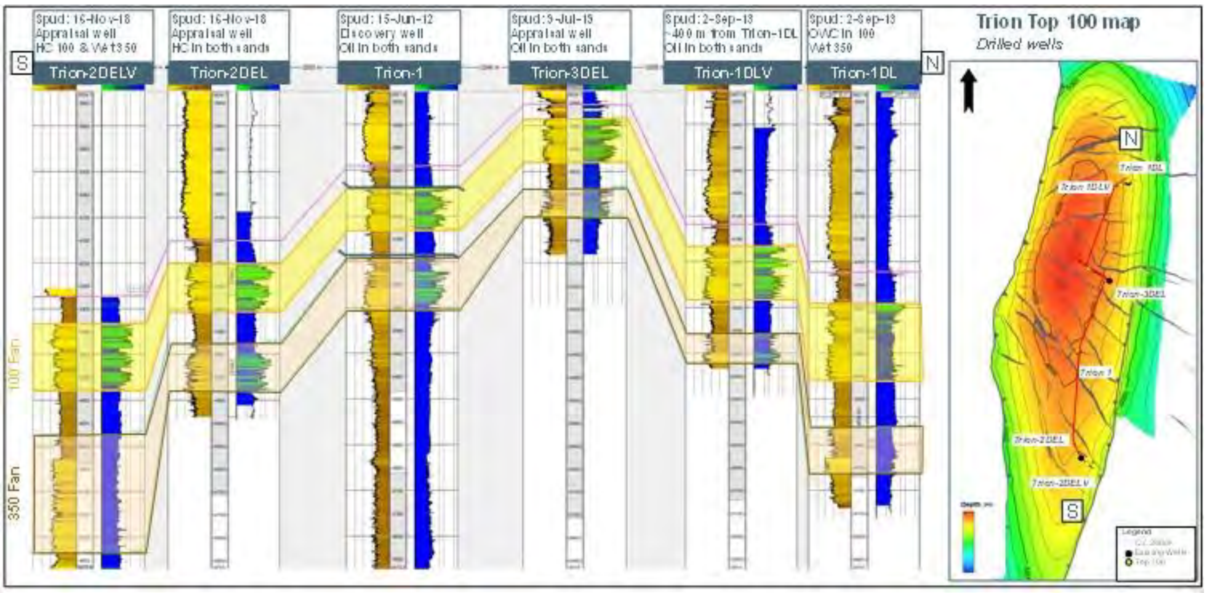
Property	100 Fan	350 Fan
Gross thickness (m)	116	92
Net thickness (m)	77	35
NTG ratio (%)	66	36
Porosity (%)	29	25
Water saturation (%)	42	39
Permeability (mD)	162	42

The reservoir structure has considerable relief with an oil column of more than 700 m in the 100 Fan (Figure 99). Reservoir pressure ranges from 6,400 to 7,100 psia in the 100 Fan and from 6,600 to 7,300 in the 350 Fan. Reservoir temperature varies in depth from 130 to 175 degF. High structural relief favours recovery by waterflooding and gas injection, the recovery mechanisms of choice.

During the DST of Trion-1DLV, a 19 m interval out of a gross thickness of 86 m was perforated. The DST was carried out under sub-optimal conditions with large string size causing unstable flow, high skin (10) caused by completion method and intermittent weather disruptions. Nonetheless, interpretation of the available data showed no barrier within the 365 m radius of investigation and permeability of approximately 74 mD.

Formation pressures measured in several wells have shown the likelihood of compartmentalisation of the reservoirs. The overall interpretation, which BHP Petroleum has used in its reference case model and is reasonable, is that barriers are present in the 350 Fan between Trion-2DEL/V and Trion-1 and between Trion-1DLV and Trion-3DEL, and that similar barriers might be present in the 100 Fan. It is also possible that there are more compartments in the field, and BHP Petroleum has taken this into consideration for well planning.

Figure 99: Cross Section Across Trion Structure



Source: BHP Petroleum

Within the 100 Fan, all wells had ODTs, except Trion-1DL, which intersected an OWC at 4,335 mss, supported by pressure data and petrophysical interpretation. Within the 350 Fan, Trion-1DL and Trion-2DELV intersected water bearing formation and all other wells had ODTs, except Trion-1DLV, which might have intersected an OWC at its base, at 4,487 mss, a depth that is supported by extrapolation of pressure gradients. Extrapolation of pressure gradients in Trion-2DEL/V implies an OWC at 4,578 mss.

BHP Petroleum has relied on seismic evidence for identifying fluid contacts, supported by petrophysics and interpretation of pressure gradients. The field has been divided into seven regions with different fluid contacts based largely on seismic attribute evidence. In the 100 Fan, the OWC is interpreted to vary between 4,368 and 4,510 mss and in the 350 Fan, between 4,450 and 4,578 mss.

No free gas has yet been intersected, but oil properties suggest the likely presence of a gas cap in the 350 Fan, with a GOC interpreted at 3,962 mss in the Trion-1DL/V area and 4,017 mss elsewhere. Oil samples from the 100 Fan suggest that the saturation pressure of the oil in this reservoir is less than the pressure projected at the crest of the structure and hence that the presence of a gas cap is unlikely.

The 100 Fan and 350 Fan have significantly different fluid properties and oil samples also show vertical and horizontal variation in composition within the reservoirs. In the 100 Fan the API density decreases with increasing depth from 26 to 17 °API while in the 350 Fan the API density decreases from 34 to 22 °API. Within the 350 Fan, oil properties in the Trion-1 DL/V area differ from those elsewhere, with the oil being apparently higher API and lower viscosity, although the fluid samples from this region were contaminated and less reliable (Table 65).

Table 65: Trion Oil Properties

Depth Location	100 Fan			350 Fan			350 Fan at Trion-1DL/V		
	GOR (scf/stb)	Bo (rb/stb)	Visc. (cP)	GOR (scf/stb)	Bo (rb/stb)	Visc. (cP)	GOR (scf/stb)	Bo (rb/stb)	Visc. (cP)
At GOC	1,300	1.54	0.7	1,550	1.65	0.4	1,900	1.82	0.2
At OWC	350	1.14	7.0	500	1.21	4.4	1,000	1.44	0.7
Average	770	1.31	2.3	1,040	1.43	1.2	1,480	1.64	0.4

9.1.2 Field Development Plan and Production Profiles

The depletion plan for Trion is an edge waterflood with crestal gas injection focused on the eastern flank of the elongated structure where the oil is interpreted to be concentrated in good quality reservoir. The high relief of the structure offers benefits for sweep efficiency from displacing fluids due to gravity effects. The field is compartmentalised although the extent of the compartmentalisation is not yet fully understood. Many semi-parallel faults are clearly interpreted on seismic data extending from the crest of the structure towards the OWC. The fault pattern divides the elongated field into reasonably well defined segments on the eastern flank. BHP Petroleum's approach is therefore to position a water injector and producer pair of wells in each compartment, as far as possible. This means each potential compartment is developed semi-independently and this approach goes some way to mitigate the potentially adverse effects of compartmentalisation.

The field will be developed with subsea wells tied back to a floating production unit (FPU). Stabilised crude will be sent to a floating storage and offloading facility (FSO) for export via tanker. Artificial lift will be with riser-based gas lift. The facility capacities are shown in Table 66.

Table 66: Trion Facilities Specifications

Item	Description/Capacity
Nameplate oil capacity (Mbopd)	100
Dry oil uplift	20%
Produced gas handling capacity (MMscfd)	145
Gas injection capacity (MMscfd)	133
Produced water handling (Mbwpd)	60 expandable to 90
Water injection capacity (Mbwpd)	140
Production uptime	92%
Water injection uptime	80%
Gas injection uptime	97%
Facility design life	30 years

The field will be developed in three phases with a total of 14 production wells, ten water injection wells and three crestal gas injection wells. The production and water injection wells planned for each phase are shown in Table 67 and the proposed well locations are shown in Figure 100. Note that two of these well (producer "A" and water injector

"Z") are located in the northern extremity of the field, in a compartment which is interpreted to be separated from the main field by a fault with significant throw and is therefore considered prospective (i.e. undiscovered). Oil potentially recoverable from this compartment is not reported as Contingent Resources.

All of the wells will be completed in the 100 Fan and a subset (11 of 14 producers, seven of ten water injectors and all three gas injectors) will have dual completions in both the 100 Fan and 350 Fan. The producers and gas injectors will be fitted with downhole flow control (DHFC) devices that will allow selective shutting off of individual reservoirs. The water injection wells will not be fitted with DHFC devices.

On 19th December 2021, BHP Petroleum announced that it had filed with the National Hydrocarbons Commission (CNH) a Declaration of Commerciality (DoC) in respect of the Trion discovery area. The DoC confirms that BHP Petroleum and PEMEX consider the Trion discovery area to be commercial subject to and in accordance with the terms of the Licence. On 5th August 2021, the BHP Petroleum Board approved US$258 million in capital expenditure to move the Trion project into the Front End Engineering Design (FEED) phase.

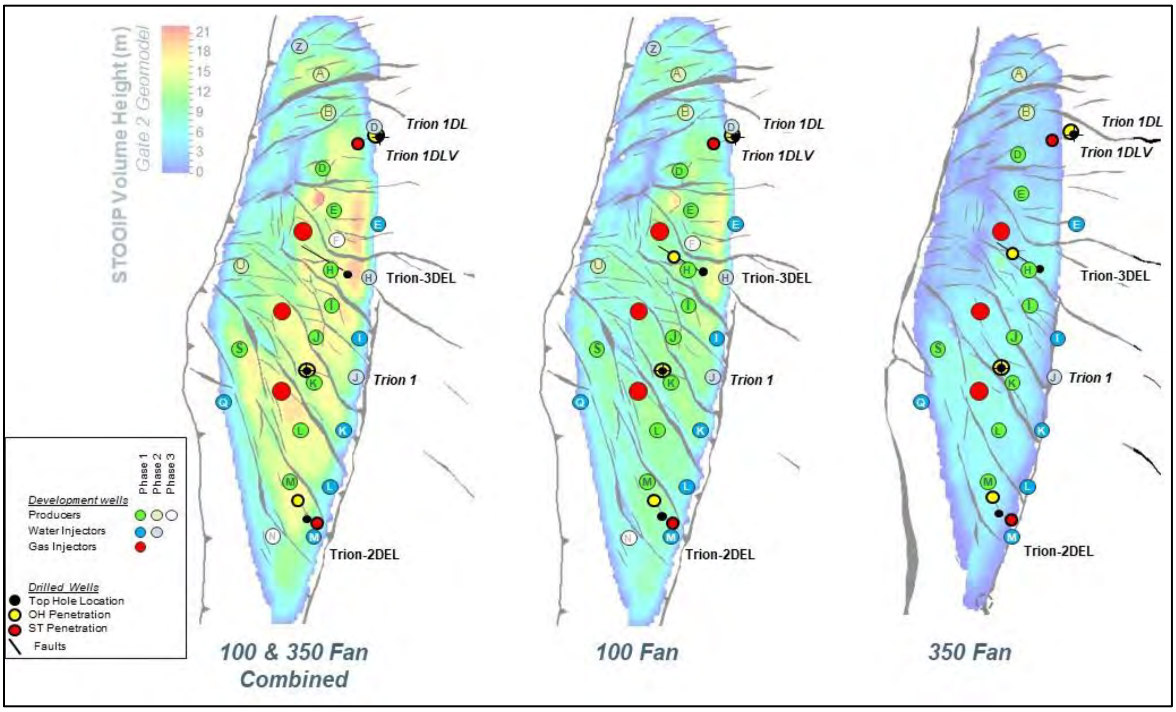
Table 67: Trion Development Phases and Wells

Phase 1		Phase 2		Phase 3	
Producers	Water Injectors	Producers	Water Injectors	Producers	Water Injectors
D			D		
E	E				
H			H		
I	I				
J			J		
K	K				
L	L				
M	M				
S	Q				
		A	Z		
		B			
		U			
				F	
				N	
9	**6**	**3**	**4**	**2**	**0**

Notes:

1. Wells A and Z are in a prospective (undiscovered) region.
2. In addition to the well shown here, three crestal gas injectors will be drilled in the crest of the structure and completed in both fans.

Figure 100: Development Wells for Trion



Source: BHP Petroleum

Production start-up is expected to occur late in 2026, taking into account the current schedule. Phase 1 drilling will include pre-drilled wells and drilling through the ramp-up period. Phase 2 drilling will commence approximately two years after start-up and Phase 3 will commence approximately eight years after start-up.

The gas injection wells are intended to re-inject all produced gas as far as possible for pressure maintenance. Gas that cannot be injected will be exported via pipeline. The gas export volumes estimated by BHP Petroleum from the dynamic simulation model are dependent upon the simulator's projection of GOR, and re-injection capacity, both of which are sensitive to the assumptions and controls imposed in the simulation model. The gas export pipeline route has not yet been finalised although there are options to tie into existing infrastructure. Estimates of sales gas volumes are small, but an export option is an integral part of the development to avoid oil production becoming constrained by gas injection limitations.

BHP Petroleum has carried out dynamic simulation studies including an uncertainty analysis for development planning, and has provided GaffneyCline with a "reference case" model which forms the basis for BHP Petroleum's Field Development Plan. GaffneyCline has reviewed the dynamic model and found it suitable to underpin 2C Contingent Resources estimates.

Estimates of recoverable oil volumes are shown in Table 69. Note that the volumes in these tables exclude the undiscovered (prospective) area in the north of the field, which could contain ~100 MMBbl of STOIIP, of which ~26 MMBbl of incremental oil could be recovered if the proposed wells (A and Z) successfully meet their objectives.

9.1.3 Cost Estimates

BHP Petroleum has provided GaffneyCline with a range of project cost and supporting documentation which GaffneyCline has reviewed.

The BHP Petroleum CAPEX estimates have been reviewed and appear to be credible, based on GaffneyCline's experience of comparable developments. Adjustments have been made for the Contingent Resources to reflect the removal of producer well "A" and water injector well "Z", which are both considered prospective and not included in the Contingent Resources. CAPEX (from 2022 onwards) for the Contingent Resources case is shown in Table 68.

Table 68: Trion Gross CAPEX Estimates for Contingent Resources

Item	CAPEX (US$MM)
Exploration Wells	80
Development Wells	2,226
Facilities	4,159
Pipelines	141
Owners Cost	24
Total	**6,630**

The OPEX estimates for the development were evaluated by GaffneyCline, taking into consideration the development scope, planned activities and work programs outlined in the documentation. The total OPEX is broken down into fixed (asset management, maintenance, FPSO lease) and variable (US$/Bbl or US$/Mscf) elements.

The OPEX costs provided in the economic model and supporting documentation have been reviewed and appear to be credible, based on GaffneyCline's experience. The OPEX profiles have been adjusted to account for changes in the variable OPEX resulting from differences between BHP Petroleum's production profiles compared with the GaffneyCline profiles.

For the Contingent Resources, ABEX figures provided by BHP Petroleum have been reviewed and adopted unchanged.

9.1.4 Resources Estimates

The gross volume of oil estimated to be recoverable from the discovered part of the field prior to expiration of the primary licence term in 2052 is 428 MMBbl (Table 69), classified as 2C Contingent Resources Development Pending. The volume of gas estimated to be produced and used as fuel (consumed in operations, CiO) during the licence period is 99 Bscf.

Additionally, estimates of sales volumes of gas prior to expiration of the primary licence term in 2052 of approximately 32 Bscf have been classified as 2C Contingent Resources Development Pending. These sales gas estimates are based on surplus produced gas that cannot be injected, as forecast by the simulator. They are dependent on a variety of sensitive reservoir performance parameters in the dynamic simulation model and are thus uncertain. There is no formal sales agreement to cover these volumes, although it is understood that gas demand in Mexico is such that gas sales are low risk. Gas sales volumes shown in Table 69 are small.

Further volumes of oil potentially recoverable after licence expiry (43 MMBbl) and potential sales gas from the gas cap blowdown (176 Bscf) are reported as Contingent Resources Development Unclarified. The volume of CiO gas estimated to be produced and consumed after licence expiry is 42 Bscf.

Table 69: Trion Hydrocarbons Initially in Place and Gross Recoverable Volumes

Item	Formation	Quantity
STOIIP in discovered area (MMBbl)	100 Fan	1,003
	350 Fan	365
	Total	**1,368**
Solution GIIP (approximate) (Bscf)	100 Fan	772
	350 Fan	385
	Total	**1,158**
GIIP in gas cap (Bscf)	350 Fan	42
Oil recovered within licence period to 2052 (MMBbl)	**Field**	**428**
Recovery factor at licence expiry (2052)	Field	31%
Ultimate oil recovery (nominally in 2066) (MMBbl)	Field	471
Ultimate recovery factor (nominally in 2066)	Field	34%
Oil recovered after licence expiry (MMBbl)	**Field**	**43**

10 BHP Petroleum Global Exploration Portfolio

BHP Petroleum's global exploration portfolio consists of assets in Mexico, Trinidad and Tobago, Canada, Australia and USA. These prospects range from NFE opportunities in Mexico, Trinidad and Tobago, Australia and USA to stand-alone exploration projects in the USA and Canada.

All of the prospects discussed here could potentially be drilled within the next five (5) years; additional prospectivity with no planned drilling has been excluded from the assessment.

BHP Petroleum has identified two gas Prospects with 2U (Best estimate) Prospective Resources varying between 85 and 300 Bscf and Chance of Geologic Success (P_g) between 85% and 90%, plus 11 oil Prospects with 2U Prospective Resources varying between 4.4 and 440 MMBbl and P_g between 11% and 90%.

GaffneyCline has reviewed the Prospects mentioned above. This review has broadly confirmed the assessments by the BHP Petroleum, although GaffneyCline has modified both the Prospective Resource estimates and P_g where it deems it to be required. No further details are provided here as they are deemed to be commercially sensitive.

Economic Assessment

GaffneyCline has conducted an economic assessment of Woodside and BHP Petroleum assets in order to derive the economic limit for production, the Net Entitlement Reserves and the Net Present Values (NPVs) associated with the 1P and 2P Reserves cases. The assessments are based upon GaffneyCline's understanding of the fiscal terms governing these assets and the various economic and commercial assumptions described herein.

11 Assumptions and Inputs

11.1 Macro-Economic Assumptions

- Effective date of the economic analysis is 31st December 2021.
- CAPEX, OPEX and D&R costs are in US$2022 real terms, then escalated 2% p.a. from 2023.

11.2 Oil and Gas Pricing Scenarios

GaffneyCline's price scenario for 1Q 2022, shown in Table 70, has been used as the reference price for global benchmarks in the economic analysis.

Table 70: GaffneyCline 1Q 2022 Price Scenario for Global Price Benchmarks

Year	Brent Crude (US$/Bbl)	West Texas Intermediate (US$/Bbl)	Henry Hub Gas (US$/MM Btu)
2022	75.92	72.69	3.78
2023	71.00	66.91	3.42
2024	70.00	66.00	3.20
2025	71.40	67.32	3.26
2026+	+2% per annum	+2% per annum	+2% per annum

11.3 Realized Product Prices

GaffneyCline estimated product price differentials based on 2021 actual realized prices provided by Woodside and BHP Petroleum. For contracted prices where applicable, GaffneyCline reviewed pricing information made available by Woodside and BHP Petroleum and accepted them to be reasonable. Details of pricing are not included as they are confidential.

12 Fiscal Regimes and Modelling Assumptions

12.1 Woodside Australia

Woodside's Australian petroleum projects are subject to the Petroleum Resource Rent Tax (PRRT) Fiscal Regime. Fiscal terms are summarized as below:

- Excise duty is applicable to oil and condensate produced from the North West Shelf fields. A royalty regime also applies to production from the North West Shelf fields.
- PRRT is applied at 40% of taxable profits derived from hydrocarbon production. PRRT payments are deductible for income tax purposes. The tax applies to profits derived from a petroleum project and not to the value or volume of production as with royalty and excise regimes. Deductions are available for all allowable expenditures and uplifts are applied to the carried-forward expenditure to ensure that PRRT taxes the economic rent generated from a petroleum project in a financial year.
- PRRT Payable is calculated as follows:
    - PRRT Payable = Taxable Profit x PRRT Rate (40%);
    - Taxable Profit = Assessable Receipts – Deductible Expenditures;
    - Assessable Receipts include petroleum receipts, tolling receipts, exploration recovery receipts, property receipts, miscellaneous compensation receipts, employee amenities receipts, incidental production receipts;
    - Expenditures are deductible in the year they are incurred. Expenditures include general project expenditures, exploration expenditure or closing-down expenditures;
    - General project expenditures consist of costs incurred in carrying out or providing the operations, facilities and other activities in relation to an oil and gas project;
    - Exploration expenditure is cost incurred in the exploration for oil and gas in an eligible exploration or recovery area;
    - Closing-down expenditure related to abandonment and decommissioning costs; and
    - Expenditures that are excluded are financing costs, dividend payments, acquisition costs, private overriding royalties, income tax and GST payments, indirect administration costs.
- Depreciation of historical CAPEX for each asset has been provided by Woodside.
- Applicable income tax rate of 30%.

12.2 Woodside Sangomar (Senegal)

Woodside holds 82% working interest in the Sangomar field in Senegal which operates under a Production Sharing Contract (PSC). The key elements of the PSC fiscal regime are as follows:

- Maximum Cost Recovery is 75% of Production Revenue;

- Recoverable Costs comprise OPEX, FPSO and Pipeline CAPEX depreciation (10 years straight line basis), all other post-FID Development CAPEX depreciation (5 years straight line basis), pre-FID CAPEX on an expensed basis, Abandonment Provision payments, Training Fees, Surface Rentals, Local Element Contribution and Customs Duty. Unrecovered costs can be carried forward indefinitely;
- Profit Oil (Production Revenue minus Cost Recovery) is split between Contractor and Government by production tranches as shown in Table 71:

Table 71: Profit Oil Split for Sangomar

Tranche	Oil Production Rate (Mbopd)	Government Profit Share (%)
Tranche 1	0 – 50	15%
Tranche 2	50 – 100	20%
Tranche 3	100 – 150	25%
Tranche 4	150 – 200	30%
Tranche 5	> 200	

- Abandonment Provision payments must be paid into an escrow account from the earliest of 6 years before economic limit or the date at which 70% of recoverable reserves have been produced;
- Other Levies and Payments:
  1. Local Economic Contribution comprises Contribution on Value Added (CVA) and Contribution on Rental Value (CRV);
  2. CVA is calculated as 1% PSC revenue minus operating expenditure;
  3. CRV is calculated on the rental value of the hull of the FPSO;
  4. Customs Duty levied at 2.3% of the imported value of the FPSO during the development phase; and
  5. Surface Rentals are calculated at US$15/sq.km contract area annually. Annual Training Fee payable is US$0.4 MM.
- Corporate Income Tax (CIT) is payable at 33% of Taxable Income. Deductions to calculate Taxable Income are subdivided into those that have a 3-year limit on loss carry-forward (such as pre-FID CAPEX, OPEX, Abandonment Provision payments, Training Fees, Surface Rentals, LEC and Customs Duty) and Deductions with unlimited carry forward (such as post-FID CAPEX); and
- Branch Profit Tax (BPT) at the rate of 10% is payable on the CIT taxable income net of CIT.
- Note that CIT and BPT have no impact on ELT calculations.

Future contingent payments related to transactions with Cairn Energy and FAR Limited, opening balances and depreciation schedules of CAPEX already placed in service were included in asset evaluation based on data provided by Woodside.

12.3 BHP Petroleum Australia

BHP Petroleum's Australia assets are governed under the Petroleum Resource Rent Tax (PRRT) Fiscal Regime, the terms of which are summarized in Section 12.1.

Depreciation of historical CAPEX for each asset has been provided by BHP Petroleum.

The following information supplied by BHP Petroleum has also been used in the economic analysis:

- Contracted gas prices and annual contracted volumes;
- Balances for calculating depreciation for income tax and PRRT;
- Revenues and costs related to the pipeline tariff in Bass Strait and Macedon;
- Hydrocarbon product prices – no historical product prices have been provided to verify any differentials to the benchmark crude prices such as Brent or WTI; and
- PRRT and tax credit related to future abandonment costs.

12.4 BHP Petroleum US Gulf of Mexico

Key terms of the US Gulf of Mexico fiscal regime are as follows:

- The US Gulf of Mexico assets follows a simple royalty/tax regime with the governmental take comprising of royalty and the standard corporation tax. BHP Petroleum Working Interest and Royalty rates of each asset used for the assessment are shown in Table 72.
- Corporate Tax rate of 21% was assumed and a seven year modified accelerated cost recovery system (MACRS) is used for depreciation of all capital expenditure. Opening balances, cost depletion and other depreciation balance calculations have been made available by BHP Petroleum.
- Note that Corporate Tax has no impact on ELT calculations.
- Licences are expected to be renewed until the economic limit of the asset is reached.

Table 72: BHP Petroleum US Gulf of Mexico Assets Working Interest and Royalty Rates

Asset	Working Interest (%)	Royalty Rate (%)	Effective Royalty Rate (%)
Shenzi	72.00	[1]12.50	10.58
Atlantis	44.00	12.50	12.50
Mad Dog	23.90	12.70	12.70

Notes:

1. Shenzi is made up of 5 blocks and royalty relief of up to 87.5 MMboe of production is applicable per block. Two blocks have exhausted the royalty relief and the remaining 3 blocks are not expected to reach relief limit within the evaluation period. The effective royalty is the weighted average royalty of the five blocks and is based on data shared by BHP.
2. Mad Dog Royalty rate is the average of blocks with 12.5% and 18.75% rates with an effective rate of 12.702%

12.5 BHP Petroleum Trinidad and Tobago (T&T) Assets

BHP Petroleum's Trinidad and Tobago assets comprise of Block 2(c) and Block 3(a). BHP Petroleum holds a 45% working interest position in the Block 2(c) production sharing contract (PSC) and a 68.46% working interest position in the Block 3(a) PSC. Net interests are determined by the terms of the PSC for each block and may vary from the working interest.

Actual terms are excluded due to confidentiality.

13 Economics Analysis Results

Net Entitlement Reserves of Woodside and BHP Petroleum assets are shown in Table 2 in the Summary section of this report. Post-tax NPVs net to Woodside and BHP for each Reserves case are shown in Table 73. The NPVs at 10% discount rate are the same as those shown in Table 4 in the Summary section.

Table 73: Post-Tax NPV of Future Cash Flows from Reserves at Different Discount Rates, as at 31st December 2021

(a) Net to Woodside

Country	Asset / Project	Post-Tax Net Present Value (US$MM)					
		Proved			Proved plus Probable		
		7.5%	10.0%	12.5%	7.5%	10.0%	12.5%
Australia	North West Shelf	1,633	1,567	1,501	2,403	2,244	2,104
	Wheatstone	2,223	2,057	1,910	3,188	2,834	2,545
	Pluto	8,192	7,712	7,281	9,493	8,807	8,207
	Scarborough	2,023	1,140	466	4,111	2,419	1,256
	Greater Enfield	198	233	258	504	514	519
Senegal	Sangomar	1,451	1,198	980	2,695	2,265	1,904
Total		**15,721**	**13,907**	**12,397**	**22,394**	**19,083**	**16,534**

(continued on next page)

(b) Net to BHP Petroleum

Country	Asset / Project	Post-Tax Net Present Value (US$ MM)					
		Proved			Proved plus Probable		
		7.5%	10.0%	12.5%	7.5%	10.0%	12.5%
Australia	North West Shelf	1,590	1,520	1,454	2,328	2,170	2,030
	Bass Strait	881	898	903	1,744	1,695	1,644
	Macedon	234	227	220	279	267	256
	Pyrenees	54	69	80	195	197	193
	Scarborough	729	411	168	1,482	872	453
US GOM	Shenzi	1,686	1,610	1,534	2,535	2,319	2,134
	Shenzi North	323	265	216	693	588	501
	Atlantis	1,217	1,190	1,156	3,605	3,293	3,030
	Mad Dog	2,585	2,258	2,001	3,707	3,113	2,672
Trinidad & Tobago	Angostura	82	79	77	135	129	123
	Ruby	14	15	16	55	53	52
Total		**9,394**	**8,542**	**7,824**	**16,758**	**14,697**	**13,089**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the assets.
2. The NPVs reported here do not represent an opinion as to the market value of the asset or any interest therein.
3. The NPVs reported here do not include any corporate adjustments, such as net debt or corporate costs, and as a result should not be used to assess the relative net asset values of the two companies.

13.1 Sensitivity Analysis

GaffneyCline has conducted a sensitivity analysis of Proved and Proved plus Probable case NPVs at 10% discount rate to prices and costs. The following changes to input factors have been conducted:

- Product price sensitivity (±US$10/Bbl for oil and ±20% for gas and other products);
- CAPEX sensitivity (±20%); and
- OPEX sensitivity (±20%).

Results of sensitivity analysis are shown in Table 74 to Table 77.

Table 74: Sensitivity of Post-Tax NPV (US$ MM) at 10% Discount Rate of Future Cash Flows from Proved Reserves Net to Woodside, as of 31st December 2021

Country	Asset / Project	+US$10/Bbl, +20% Other Product Prices	-US$10/Bbl, -20% Other Product Prices	-20% CAPEX	+20% CAPEX	-20% OPEX	+20% OPEX
Australia	North West Shelf	1,934	1,199	1,691	1,442	1,709	1,424
	Wheatstone	2,408	1,706	2,142	1,971	2,101	2,013
	Pluto	8,450	6,634	7,796	7,615	7,888	7,492
	Scarborough	2,122	152	1,624	655	1,982	296
	Greater Enfield	340	139	303	163	311	174
Senegal	Sangomar	1,567	687	1,473	882	1,335	1,070
Total		**16,820**	**10,518**	**15,028**	**12,728**	**15,326**	**12,469**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the assets.
2. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. The NPVs reported here do not include any corporate adjustments, such as net debt or corporate costs, and as a result should not be used to assess the relative net asset values of the two companies.

Table 75: Sensitivity of Post-Tax NPV (US$ MM) at 10% Discount Rate of Future Cash Flows from Proved Reserves Net to BHP Petroleum, as of 31st December 2021

Country	Asset / Project	+US$10/Bbl, +20% Other Product Prices	-US$10/Bbl, -20% Other Product Prices	-20% CAPEX	+20% CAPEX	-20% OPEX	+20% OPEX
Australia	North West Shelf	1,869	1,172	1,636	1,404	1,648	1,392
	Bass Strait	1,096	683	1,045	739	980	797
	Macedon	283	172	238	216	236	219
	Pyrenees	113	34	93	44	96	51
	Scarborough	765	55	585	236	715	107
US GOM	Shenzi	1,954	1,266	1,672	1,548	1,719	1,501
	Shenzi North	345	185	315	215	273	257
	Atlantis	1,541	839	1,283	1,096	1,350	1,029
	Mad Dog	2,765	1,751	2,386	2,130	2,408	2,108
Trinidad & Tobago	Angostura	123	21	91	60	93	60
	Ruby	33	-3	23	7	20	10
Total		**10,886**	**6,175**	**9,368**	**7,697**	**9,538**	**7,530**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the assets.
2. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. The NPVs reported here do not include any corporate adjustments, such as net debt or corporate costs, and as a result should not be used to assess the relative net asset values of the two companies.

Table 76: Sensitivity of Post-Tax NPV (US$ MM) at 10% Discount Rate of Future Cash Flows from Proved plus Probable Reserves Net to Woodside, as of 31st December 2021

Country	Asset / Project	+US$10/Bbl, +20% Other Product Prices	-US$10/Bbl, -20% Other Product Prices	-20% CAPEX	+20% CAPEX	-20% OPEX	+20% OPEX
Australia	North West Shelf	2,714	1,775	2,370	2,119	2,393	2,096
	Wheatstone	3,297	2,372	2,919	2,749	2,894	2,774
	Pluto	9,653	7,615	8,888	8,710	9,033	8,536
	Scarborough	3,630	1,199	2,892	1,941	3,462	1,371
	Greater Enfield	638	389	580	449	573	455
Senegal	Sangomar	2,717	1,807	2,507	2,019	2,386	2,155
Total		**22,649**	**15,158**	**20,156**	**17,987**	**20,742**	**17,388**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the assets.
2. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. The NPVs reported here do not include any corporate adjustments, such as net debt or corporate costs, and as a result should not be used to assess the relative net asset values of the two companies.

Table 77: Sensitivity of Post-Tax NPV (US$ MM) at 10% Discount Rate of Future Cash Flows from Proved plus Probable Reserves Net to BHP Petroleum, as of 31st December 2021

Country	Asset / Project	+US$10/Bbl, +20% Other Product Prices	-US$10/Bbl, -20% Other Product Prices	-20% CAPEX	+20% CAPEX	-20% OPEX	+20% OPEX
Australia	North West Shelf	2,616	1,724	2,287	2,053	2,304	2,036
	Bass Strait	2,018	1,367	1,816	1,571	1,807	1,582
	Macedon	334	201	279	256	277	258
	Pyrenees	248	146	210	184	224	170
	Scarborough	1,309	432	1,043	700	1,248	494
US GOM	Shenzi	2,761	1,878	2,371	2,267	2,440	2,199
	Shenzi North	716	460	638	538	599	577
	Atlantis	3,981	2,606	3,367	3,219	3,544	3,042
	Mad Dog	3,734	2,492	3,239	2,986	3,270	2,955
Trinidad & Tobago	Angostura	181	64	140	114	142	113
	Ruby	79	29	61	46	59	48
Total		**17,977**	**11,397**	**15,451**	**13,934**	**15,914**	**13,474**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the assets.
2. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.
3. The NPVs reported here do not include any corporate adjustments, such as net debt or corporate costs, and as a result should not be used to assess the relative net asset values of the two companies.

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, or at the direction of, Woodside or BHP Petroleum or obtained from the public domain, 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, Woodside or BHP Petroleum or obtained from the public domain, and has accepted the accuracy and completeness of these 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, engineering and commercial 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.

In the preparation of this report, GaffneyCline has used definitions contained within 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 (see Appendix I).

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 resources 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, resources 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.

Oil and condensate volumes are reported in millions (10^6) of barrels at stock tank conditions (MMBbl). Natural gas volumes have been quoted in billions (10^9) of standard cubic feet (Bscf). Volumes are sales gas, after an allocation has been made for fuel and process shrinkage losses, unless other described. Standard conditions are defined as 14.7 psia and 60°F.

GaffneyCline's review and audit involved reviewing pertinent facts, interpretations and assumptions made by Woodside and BHP Petroleum 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 and Resources

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 (as of the evaluation's effective date) 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 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.

Contingent Resources are 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 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.

It must be appreciated that the Contingent Resources reported herein are unrisked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources. Once discovered, the chance that the accumulation will be commercially developed is referred to as the "chance of development".

Prospective Resources are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. 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.

There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective Resource volumes are presented as unrisked.

Reserves net to Woodside and BHP Petroleum are quoted as Net Entitlement Reserves, reflecting the terms of the applicable Production Sharing Contracts (PSC) as appropriate. Contingent Resources are presented at a gross field level and a net working interest level, as the development plans are not yet sufficiently mature for net entitlements to be estimated.

GaffneyCline has not undertaken a site visit and inspection because it was not included in the scope of work and not considered necessary for the purpose of this report. 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.

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 licences and consents (including planning permission, financial interest relationships, or encumbrances thereon for any part of the appraised properties).

Qualifications

GaffneyCline is an independent international energy advisory group of more than 55 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

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 Woodside and BHP Petroleum. Furthermore, the management and employees of GaffneyCline have no interest in any of the assets evaluated or are 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.

The team was led by Mr Drew Powell, Projects Director, who has 32 years' industry experience. He holds a Bachelor of Engineering Degree in Chemical Engineering from the University of Aston, Birmingham. He is both a Fellow of the Institution of Chemical Engineers and a Chartered Engineer. He is also a member Society of Petroleum Engineers and Association of International Petroleum Negotiators.

The report was reviewed by Dr. John Barker, Technical Director, Reservoir Engineering, who has 37 years' industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

It has been a pleasure preparing this Competent Person’s Report for Woodside Petroleum Limited.

Yours sincerely,

Gaffney, Cline & Associates Limited

Project Manager
Mr Drew Powell

Reviewed by
Dr John Barker

Appendix I
SPE PRMS 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 June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	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.

[1] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	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.
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.

Class/Sub-Class	Definition	Guidelines
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.
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—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—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.

Category	Definition	Guidelines
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.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

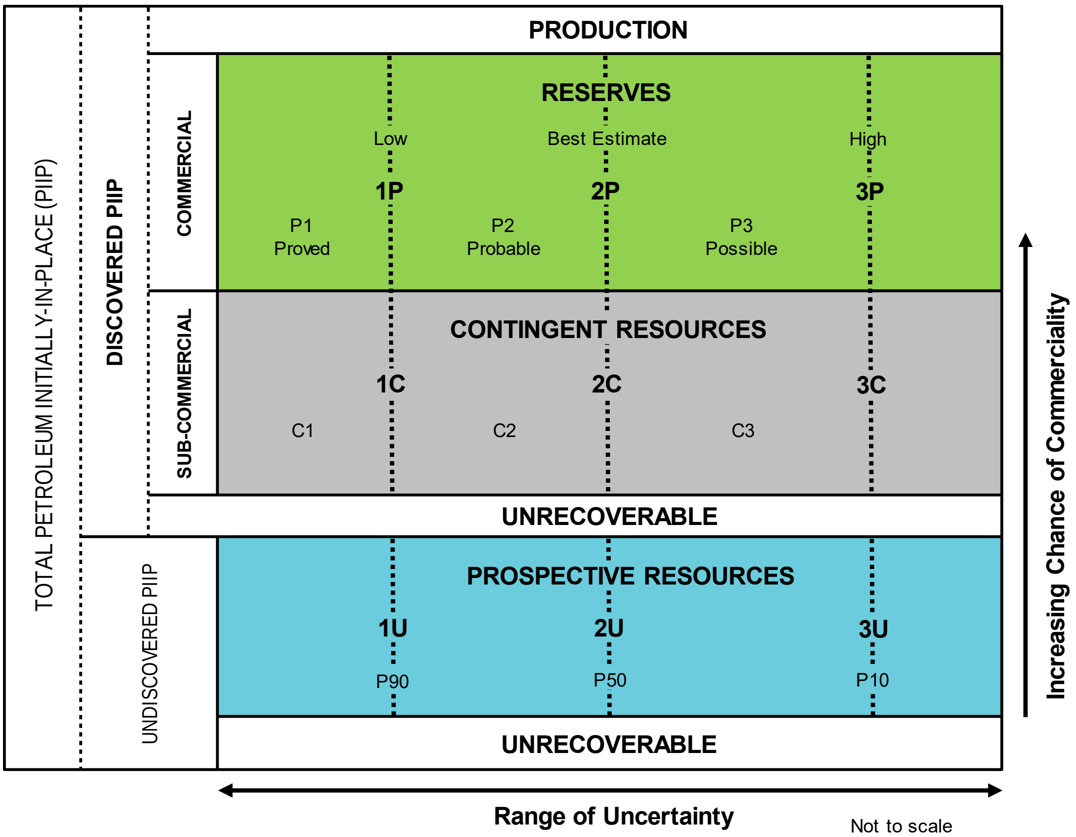
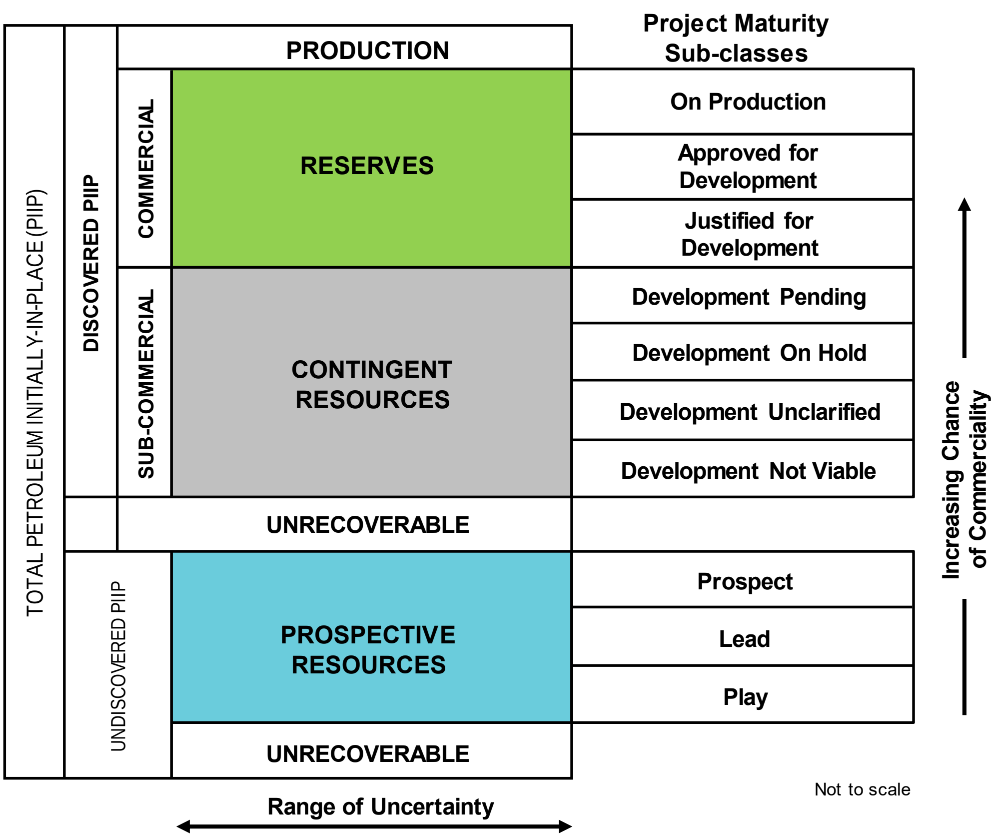


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



Appendix II
Glossary

GLOSSARY

Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment expenditure
ACQ	Annual contract quantity
AGP	Angostura gas project
API	American Petroleum Institute
°API	Degrees API (a measure of oil density)
AAPG	American Association of Petroleum Geologists
AVO	Amplitude versus offset
B	Billion (10^9)
bara	Measure of pressure (absolute)
barg	Measure of pressure (gauge, relative to atmospheric)
Bbl	Barrels
/Bbl	Per barrel
BBbl	Billion barrels
bcpd	Barrels of condensate per day
BHP	Bottom hole pressure
blpd	Barrels of liquid per day
Bm^3	Billion cubic metres
Bo	Oil formation volume factor
boe	Barrels of oil equivalent
boepd	Barrels of oil equivalent per day
BOP	Blow out preventer
blpd	Barrels of liquid per day
bopd	Barrels of oil per day
bpd	Barrels per day
bwpd	Barrels of water per day
BPT	Branch profit tax
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
BS&W	Bottom sediment and water
BTU	British thermal units
bwpd	Barrels of water per day
°C	Degrees Celsius
CAPEX	Capital expenditure
CBM	Coal bed methane
cf	Standard cubic feet
cfd	Standard cubic feet per day
CIIP	Condensate initially in place
CiO	Consumed in operations
CIT	Corporate income tax
CGR	Condensate to gas ratio
cm	Centimetres
CMM	Coal mine methane
CO_2	Carbon dioxide
cP	Centipoise (a measure of viscosity)
CPP	Central production facility
CRV	Contribution on rental value
CSG	Coal seam gas
CT	Corporation tax
CVA	Contribution on value added
D&R	Decommissioning and restoration

DCA	Decline curve analysis
DCQ	Daily contract quantity
degC	Degrees Celsius
degF	Degrees Fahrenheit
Dev	Developed
DHFC	Downhole flow control
DHI	Direct hydrocarbon indicator
DoC	Declaration of Commerciality
DST	Drill stem test
E&A	Exploration & appraisal
E&P	Exploration and production
EBIT	Earnings before interest and tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EEA	Evaluation extension area
EI	Entitlement interest
EIA	Environmental impact assessment
ELT	Economic limit test
EMV	Expected monetary value
EoFL	End of field life
EOR	Enhanced oil recovery
ESP	Electrical submersible pump
EUR	Estimated ultimate recovery
€ / EUR	Euro
°F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FID	Final investment decision
FLNG	Floating liquefied natural gas
FPSO	Floating production, storage and offloading vessel
FPU	Floating production unit
FSO	Floating storage and offloading vessel
ft	Foot/feet
FWI	Full Waveform Inversion
FWL	Free Water Level
g	Gram
g/cc	Grams per cubic centimetre
G&A	General and administrative costs
GBP	Pounds Sterling
GCoS	Geological chance of success
GDT	Gas down to
GEP	Gas export platform
GIIP	Gas initially in place
GJ	Gigajoules (one billion Joules)
GOC	Gas oil contact
GOM	Gulf of Mexico
GOR	Gas oil ratio
GRV	Gross rock volume
GSC	Gas sales contract
GTL	Gas to liquids
GWC	Gas water contact
HCIIP	Hydrocarbons initially in place
HDT	Hydrocarbons down to
HSE	Health, Safety and Environment

HUT	Hydrocarbons up to
H_2S	Hydrogen sulphide
IOR	Improved oil recovery
IPM	Integrated production modelling
IRR	Internal rate of return
J	Joule (Metric measurement of energy; 1 kilojoule = 0.9478 BTU)
JV	Joint venture
KB	Kelly bushing
KGP	Karratha Gas Plant
kJ	Kilojoules (one thousand Joules)
KLNG	Kitimat LNG facility
km	Kilometres
km^2	Square kilometres
kPa	Kilopascal (one thousands Pascals)
kW	Kilowatt
kWh	Kilowatt hour
LKG	Lowest known gas
LKH	Lowest known hydrocarbons
LKO	Lowest known oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LSE	London Stock Exchange
LTI	Lost time injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
MBbl	Thousands of barrels
Mbopd	Thousands of barrels of oil per day
Mcf or Mscf	Thousand standard cubic feet
MCM	Management committee meeting
m^3d	Cubic metres per day
mD	Millidarcies (a measure of rock permeability)
MD	Measured depth
MDT	Modular dynamic tester (a wireline logging tool)
Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
mg/l	milligrams per litre
MJ	Megajoules (one million Joules)
Mm^3	Thousand cubic metres
Mm^3d	Thousand cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
MMcf or MMscf	Million standard cubic feet
Mode	Value that exists most frequently in a set of values = most likely
Mcfd or Mscfd	Thousand standard cubic feet per day
MMcfd or MMscfd	Million standard cubic feet per day
mss	Metres below sea level
MTC	Mass transport complex
mTVDss	Metres true vertical depth below sea level
MW	Megawatt
MWD	Measuring while drilling

MWh	Megawatt hour
mya	Million years ago
n/a	Not applicable
nD	Nano-Darcies
NFE	Near Field Exploration
NGC	Natural Gas Company of Trinidad and Tobago
NGL	Natural gas liquids
N_2	Nitrogen
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
NWS	North West Shelf
OBC	Ocean bottom cable
OBM	Oil based mud
OBN	Ocean bottom node
OCM	Operating committee meeting
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil water contact
p.a.	Per annum
Pa	Pascal (metric measurement of pressure)
P&A	Plugged and abandoned
PD	Proved developed
PDP	Proved developed producing
P_g	Geological chance of success
%	Percentage
PI	Productivity index
PJ	Petajoules (10^{15} Joules)
ppm	Parts per million
PRMS	Petroleum Resources Management System
PRRT	Petroleum resource rent tax
PSC / PSA	Production sharing contract / Production sharing agreement
PSDM	Pre/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 temperature
P10	Value with a 10% probability of being exceeded
P50	Value with a 50% probability of being exceeded
P90	Value with a 90% probability of being exceeded
RF	Recovery factor
RFT	Repeat formation tester (a wireline logging tool)
RT	Rotary table
RTM	Reverse time migration
RUB	Russian Rouble
R_w	Resistivity of water
SCAL	Special core analysis
scf	Standard cubic feet
scfd	Standard cubic feet per day
S_o	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers

SRP	Sucker rod pump
ss	Subsea
SSMPP	Subsea multiphase pumping
ST	Side track
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
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
TLP	Tension leg platform
TOC	Total organic carbon
TOP	Take or pay
tpd	Tonnes per day
TRR	Technically Recoverable Resources
TTI	Tilted transverse isotropic
TVD	True vertical depth
TVDss	True vertical depth subsea
Undev	Undeveloped
UOP	Unit of production
USGS	United States Geological Survey
US$	United States Dollar
VAT	Value added tax
Visc.	Viscosity
VSP	Vertical seismic profiling
v/v	Ratio volume to volume
WA	Western Australia
WC	Water cut
WI	Working interest
WPC	World Petroleum Council
WPP	Wellhead protector platform
WTI	West Texas Intermediate
wt%	Weight percent
WUT	Water up to
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional (time lapse)
1H13	First half (6 months) of 2013 (example of date)
1P	Proved Reserves
2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
2Q14	Second quarter (3 months) of 2014 (example of date)
1U	Low estimate of Prospective Resources
2U	Best estimate of Prospective Resource
3U	High estimate of Prospective Resources

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Appendix III
Consumed in Operations (Reserves)

Although the PRMS recommends that Reserves be sales quantities, it does allow volumes of hydrocarbons forecast to be consumed in operations (CiO) as fuel during the production of Reserves, upstream of the reference point at whch Reserves are reported, to be classified as Reserves, provided they are reported separately from sales volumes.

Woodside and BHP Petroleum customarily report CiO volumes differently. For integrated gas projects involving both an upstream component (the production facilities) and a downstream processing component (e.g. an LNG plant), Woodside reports only the downstream CiO volumes as Reserves, while BHP Petroleum reports both the upstream and downstream CiO volumes as Reserves.

Table AIII.1 shows total CiO Reserves for each asset for both companies, split into upstream and downstream components for Woodside, to facilitate comparison with prior annual reporting.

Table AIII.1: Summary of Working Interest CiO Gas Reserves as at 31st December 2021

(a) Woodside CiO Gas

Country	Asset	CiO Gas Reserves (Bscf)					
		Proved			Proved plus Probable		
		Up-stream	Down-stream	Total	Up-stream	Down-stream	Total
Australia	North West Shelf	23	77	**99**	24	100	**124**
	Wheatstone LNG (Brunello & Julimar)	23	96	**119**	35	149	**185**
	Pluto LNG	105	127	**233**	142	150	**292**
	Scarborough LNG	128	506	**634**	199	782	**980**
	Greater Enfield	21	0	**21**	24	0	**24**
Senegal	Sangomar	51	0	**51**	54	0	**54**
Total		**351**	**806**	**1,157**	**478**	**1,181**	**1,659**

(b) BHP Petroleum CiO Gas

Country	Asset	Total CiO Gas Reserves (Bscf)	
		Proved	Proved plus Probable
Australia	North West Shelf	101	127
	Bass Strait	47	57
	Macedon	16	31
	Pyrenees	0	0
	Scarborough LNG	228	353
US GOM	Shenzi	17	21
	Shenzi North	0	0
	Atlantis	16	42
	Mad Dog	28	36
Trinidad & Tobago	Angostura/Ruby	9	11
Total		**462**	**677**

Notes:

1. CiO Reserves net to company are the company's net working interest fraction of the total fuel used.
2. Totals may not exactly equal the sum of the individual entries due to rounding.
3. Woodside's estimates of downstream CiO are based on heating values per component whereas GaffneyCline has utilised average heating values for this reconciliation process.

Appendix IV
Summary of Combined Woodside and BHP Petroleum Assets as Combined Company

Table AIV.1: Summary of Net Entitlement Reserves as at 31st December 2021

(a) Combined Company Oil, Condensate and Gas

Country	Asset	Oil and Condensate Reserves (MMBbl)		Gas Reserves (Bscf)	
		Proved	Proved plus Probable	Proved	Proved plus Probable
Australia	North West Shelf	43.2	55.6	1,228	1,620
	Wheatstone LNG (Brunello & Julimar)	8.8	16.5	513	798
	Pluto LNG	19.5	24.3	1,448	1,801
	Scarborough LNG	-	-	6,479	10,108
	Greater Enfield	16.0	24.1	-	-
	Bass Strait	10.6	17.9	344	600
	Macedon	-	-	223	278
	Pyrenees	10.0	19.0	-	-
US GOM	Shenzi	64.0	91.9	6	12
	Shenzi North	16.4	26.8	5	8
	Atlantis	59.4	153.9	22	42
	Mad Dog	129.2	180.0	12	20
Trinidad & Tobago	Angostura	1.6	1.9	159	219
	Ruby	1.4	1.8	24	33
Senegal	Sangomar	100.6	148.1	-	-
Total		**480.8**	**761.7**	**10,464**	**15,539**

(b) Combined Company NGL/LPG

Country	Asset / Project	NGL/LPG Reserves (MMBbl)	
		Proved	Proved plus Probable
Australia	North West Shelf	4.7	6.4
	Bass Strait	16.5	28.8
US GOM	Shenzi	1.7	3.1
	Shenzi North	1.1	1.7
	Atlantis	2.9	5.6
Total		**26.9**	**45.6**

Notes:

1. Reserves net to company are the company's net economic entitlement under the terms of the contract that governs each asset. For Australia and USA, this is equal to the company's working interest share of gross field Reserves less any royalty taken in kind. For Senegal and Trinidad & Tobago, it is equal to the company's share of Cost Recovery, Profit Oil and Tax Barrels (if any) under the terms of the relevant PSC.
2. GOM Reserves are net of Royalty although payments are in cash.
3. Totals may not exactly equal the sum of the individual entries due to rounding.
4. For Bass Straight and NWS, NGL composition is equivalent to LPG as it includes only C3-C4 hydrocarbons. GOM NGL volumes represent C2-C5+ hydrocarbons.
5. As recommended by PRMS, GaffneyCline does not include Consumed in Operation (CiO) volumes in Reserves; GaffneyCline reports only Sales volumes as Reserves.

Table AIV.2: Summary of 2C Contingent Resources
Net to Combined Company (WI Basis), as at 31st December 2021

Country	Asset / Project	2C Contingent Resources		Classification
		Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
Australia	NWS Gas: facility upgrades, infill wells, workovers and new developments	0.6	24	Pending
		14.8	442	Unclarified
		3.8	106	Not Viable
	NWS Oil: facility upgrades, infill wells, workovers and new developments	10.8	4	Unclarified
		5.7	6	Not Viable
	Pluto turn-down rate reduction	0.6	53	Pending
	Pluto infill wells	2.7	231	Unclarified
	Brunello (Wheatstone LNG)	0.2	15	Unclarified
	Thebe and Jupiter (Greater Scarborough)	-	1,318	Pending
	WA-404-P (Remy, Martell, Martin, Noblige and Larsen Deep)	19.5	1,006	Not Viable
	Greater Enfield (incl. Vincent)	32.2	43	Not Viable
	Ragnar and Toro (WA-93-R & WA-94-R)	2.2	270	Not Viable
	Browse Basin (Torosa, Calliance and Brecknock)	119.3	4,469	On Hold
	Greater Sunrise	75.6	1,717	On Hold / Not Viable
	Bass Strait: N. Turrum, Sweetlips/Wirrah	16.3	118	Pending
	Bass Strait East Pilchard	1.8	20	Unclarified
	Macedon compression	-	41	Pending
	Macedon/Muiron infills	-	59	Unclarified
	Macedon Black Pearl tie-in	-	7	Not Viable
	Pyrenees Phase 4	3.2	-	Pending
	Pyrenees Phase 5	13.2	-	Unclarified
	Scafell	-	38	Not Viable

(Continued on next page)

Table AIV.2 (continued)

Country	Asset / Project	2C Contingent Resources		Classification
		Oil, Condensate and NGL (MMBbl)	Gas (Bscf)	
US GOM	Shenzi side-tracks & infills	25	7	Unclarified
	Wildling	36.9	11	Pending
	Atlantis SSMMP + WI + infills	66.9	28	Unclarified
	Atlantis expansions and infills	21.4	10	Not Viable
	Mad Dog WI expansion	15.9	-	Pending
	Mad Dog extensions and infills	54.3	4	Unclarified
Trinidad & Tobago	Angostura Block 2(c)	1.3	219	Not Viable
	Calypso	4.9	2,584	Unclarified
	Calypso	-	293	Not Viable
	Magellan	-	313	Not Viable
Mexico	Trion	256.8	79	Pending
	Trion post licence + gas blowdown	25.8	131	Unclarified
Myanmar	Block A6	-	567	Not Viable
Senegal	Sangomar Phase 1 WI	22.1	-	Pending
	Sangomar Phases 2-5 + Gas export	214	301	Unclarified
	FAN discovery	81	-	Unclarified
Canada	Liard	-	13,350	Not Viable

Notes:

1. Net Contingent Resources in this table are Company's working interest fraction of the gross field Contingent Resources; they do not represent the Company's actual net entitlement under the terms of the contracts that govern the assets, which would be lower for PSCs or where royalty is deductible.
2. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the asset may not be developed in the form envisaged or may not be developed at all (i.e., no "Chance of Development" (P_d) factor has been applied).
3. Only the 2C (Best estimate) Contingent Resources are presented here.
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved and the different basis on which the volumes are determined.
5. No deduction has been made for fuel, flare and shrinkage.
6. Note that on 27th January 2022 (after the effective date of this CPR), Woodside announced it was withdrawing from its interests in Myanmar.

Prospective Resources Summary

The company's global exploration portfolio consists of assets in Australia, Mexico, Trinidad and Tobago, Canada, USA, Senegal, Korea and Congo. These prospects range from NFE opportunities in Australia, Mexico, Trinidad and Tobago, USA and Senegal to stand-alone exploration projects in Australia, Canada, Korea and Congo.

All of the Prospects/Leads mentioned here are anticipated to be drilled within the next five (5) years; additional prospectivity with no firmly planned drilling has been excluded from the assessment.

The company has identified 11 gas Prospects/Leads with 2U Prospective Resources varying between 30 and 769 Bscf and P_g between 15% and 90%, plus 13 oil Prospects with 2U Prospective Resources varying between 4.4 and 440 MMBbl and P_g between 11% and 91%.

It should be noted that the P_g reported here represents an indicative estimate of the probability that drilling a prospect would result in a discovery. This does not include any assessment of the risk that the discovery, if made, may not be developed. Prospective Resources should not be aggregated with each other, or with Reserves or Contingent Resources, because of the different levels of risk involved.

Part 25 – Directors, Secretary, Registered Office and Advisers

Directors	Richard Goyder	*Chair*
	Meg O'Neill	*Chief Executive Officer and Managing Director*
	Larry Archibald	*Independent Non-Executive Director*
	Frank Cooper	*Independent Non-Executive Director*
	Swee Chen Goh	*Independent Non-Executive Director*
	Ian Macfarlane	*Independent Non-Executive Director*
	Christopher Haynes	*Independent Non-Executive Director*
	Ann Pickard	*Independent Non-Executive Director*
	Gene Tilbrook	*Independent Non-Executive Director*
	Sarah Ryan	*Independent Non-Executive Director*
	Ben Wyatt	*Independent Non-Executive Director*
Company Secretary	Warren Baillie and Andrew Cox	
Registered Office and Head Office	Mia Yellagonga 11 Mount Street Perth Western Australia 6000 Australia	
Financial Adviser	Morgan Stanley & Co. International plc 25 Cabot Square Canary Wharf London E14 4QA United Kingdom	
Legal Advisers as to English Law	KWM Europe LLP 9th Floor, 24 Monument Street London EC3R 8AJ United Kingdom	
Legal Advisers as to Australian Law	King & Wood Mallesons Level 30, QV.1 Building 250 St Georges Terrace Perth Western Australia 6000 Australia	
Auditor	Ernst & Young 11 Mounts Bay Road Perth Western Australia 6000 Australia	

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