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Announcement

Tuesday, 30 August 2022

HALF-YEAR REPORT FOR PERIOD ENDED 30 JUNE 2022

Financial highlights for H1 2022

- Net profit after tax of US$1,640 million
- Underlying net profit after tax of US$1,819 million
- Positive free cash flow of US$2,568 million
- Total tax, royalties and excise expense of US$1,476 million, equating to a statutory effective income tax rate of approximately 33% and an all-in effective tax rate of approximately 47%
- Liquidity of US$7,915 million
- Declared an interim dividend of 109 US cents per share
- Results reflect strong operational performance and realised benefits of the merger with BHP's petroleum business

Operational highlights

- Delivered production of 54.9 MMboe, including 9.7 MMboe from the former BHP Petroleum assets in June 2022
- Tolling operations commenced at NWS Project, using Pluto gas transported through the Pluto-KGP Interconnector enabling strong Pluto production performance
- Delivered subsea projects ahead of schedule and under budget: GWF-3, Pyxis Hub, Julimar-Brunello Phase 2 in Australia and Shenzi subsea multiphase pumping in US Gulf of Mexico
- Increased production capacity at Bass Strait, enabling Woodside to supply additional gas into the eastern Australian domestic gas market

Business highlights

- Completed merger with BHP's petroleum business
- Commenced trading on the London Stock Exchange and New York Stock Exchange
- Delivered post-merger synergies of approximately $100 million of the $400+ million per year target
- Scarborough and Pluto Train 2 is 18% complete: procured all major items, commenced fabrication of floating production unit (FPU) topsides and pipeline, and completed fabrication of subsea trees for initial phase
- Completed sell-down of a 49% interest in Pluto Train 2
- Sangomar Phase 1 is 63% complete: completing final dry dock activities for the FPSO, commenced subsea installation scope, and increased drilling activity with arrival of second drillship in July
- Awarded front-end engineering design (FEED) contract for the H2OK hydrogen project

Summary

Woodside recorded a half-year reported net profit after tax (NPAT) of US$1,640 million. Underlying NPAT was US$1,819 million, up 414% on the corresponding period in 2021. Operating revenue rose 132% year-on-year to US$5,810 million.

Woodside Energy CEO Meg O'Neill said the results reflect strong operational performance and higher realised prices, which more than doubled year-on-year to $96.4 per barrel of oil equivalent across the expanded portfolio.

"Our first results since the completion of the merger with BHP's petroleum business highlight the increased financial and operational strength delivered by our larger, geographically diverse portfolio of high-quality operating assets.

"Production for the half year was 19% higher at 54.9 million barrels of oil equivalent, benefiting from the contribution in the month of June of the former BHP assets and improved reliability at our LNG facilities.

"In particular, production from Pluto was increased by the start-up of Pyxis Hub and the commencement of gas flows through the Interconnector pipeline to Karratha Gas Plant. This well-timed investment allowed us to supply three LNG cargoes, one condensate cargo and pipeline gas into a strong market, generating $419 million in revenue and delivering additional value to our shareholders.

"The start-up of the Pluto-KGP Interconnector also marked the beginning of the North West Shelf Project's transformation into a tolling facility, which is essential to the long-term future of Australia's first and largest LNG plant.

"Our subsea project teams also successfully delivered the Greater Western Flank Phase 3 and Julimar-Brunello Phase 2 projects in Australia, and the Shenzi subsea multi-phase pump in the Gulf of Mexico.

"We are increasing activities at our Scarborough and Pluto Train 2 projects in Western Australia, with all major equipment items procured, fabrication of the floating production unit topsides and Pluto Train 2 construction works underway, the subsea trees for the initial development phase complete and pipeline manufacturing progressing.

"The Sangomar Field Development Phase 1 in Senegal is also progressing strongly, with drydock activities for the FPSO conversion completed during the period and the subsea installation campaign commencing in August. A second drillship commenced drilling in July, supporting the 23-well development drilling campaign.

"Woodside continues to deliver a disciplined approach to capital management, generating $2,568 million of free cash flow during the half and demonstrating our commitment to shareholder returns with the declaration of a fully franked interim dividend of 109 US cents per share. The dividend payout is based on 80% of underlying NPAT plus 80% of the merger completion payment adjusted for working capital, equivalent to returning approximately 81% of free cash flow. Our credit ratings of BBB+ and Baa1 were reaffirmed by S&P Global and Moody's respectively.

"We are the largest energy company listed in Australia and we are proud to be making a significant economic contribution through our continued investment in existing operations and growth projects and through our tax payments, including petroleum resource rent tax. We paid approximately A$700 million in Australian taxes, royalties and excise in the first half of this year.

"The upheavals in global and Australian energy markets witnessed over the course of the past six months have shone a spotlight on the importance of gas in the world's energy mix and underscores our confidence in the longer-term demand outlook for gas, which makes up 70% of Woodside's portfolio.

"Safe and reliable supplies of gas are not only critical to global energy security but will play a key role as our customers seek to decarbonise, alongside new energy sources such as hydrogen and ammonia that Woodside is investing in.

"Our strategy to thrive through the energy transition as a low-cost, lower-carbon energy provider continues to progress through recently announced initiatives across hydrogen refuelling, carbon capture and storage and carbon to products technologies," she said.

Financial summary

Key metrics

		H1 2022	H1 2021	Change %
Operating revenue	$ million	5,810	2,504	132%
EBITDA[1]	$ million	3,971	1,496	165%
EBIT[1]	$ million	2,982	621	380%
Net profit after tax (NPAT)[2,3]	$ million	1,640	317	417%
Underlying NPAT[1]	$ million	1,819	354	414%
Net cash from operating activities[4]	$ million	2,523	1,333	89%
Investment expenditure	$ million	1,550	788	97%
Capital investment expenditure[1,5]	$ million	1,509	720	110%
Exploration expenditure[1,6]	$ million	41	68	(40%)
Free cash flow[1,4,7]	$ million	2,568	326	688%
Dividends distributed	$ million	1,018	115	785%
Interim dividend declared	US cps	109	30	263%
Key ratios				
Earnings	US cps	145.5	33.3	337%
Gearing[1]	%	6.8	23.3	(17%)
Production				
Gas	MMboe	41.9	37.6	11%
Liquids	MMboe	13.0	8.7	49%
Total	MMboe	54.9	46.3	19%
Sales volumes				
Gas	MMboe	47.8	45.5	5%
Liquids	MMboe	11.8	8.4	40%
Total	MMboe	59.6	53.9	11%

Appendix 4D

Results for announcement to the market

More information is available on page 55

				US$ million
Revenue from ordinary activities	Increased	132%[8]	to	5,810
Net profit for the period attributable to equity holders of the parent[1]	Increased	417%[8]	to	1,640
Underlying net profit after tax[1]	Increased	414%[8]	to	1,819
Free cash flow[1]	Increased	688%[8]	to	2,568

Interim dividend – fully franked	109 US cps H1 2022
Record date for determining entitlements to the dividend	9 September 2022

[1] These are Alternative Performance Measures (APM) which are non-IFRS measures that are unaudited but derived from auditor reviewed Half-year Financial Statements. These measures are presented to provide further insight into Woodside's performance. Refer to Alternative Performance Measures for a reconciliation for these measures to Woodside's financial statements on pages 61-62 and Non-IFRS Measures on pages 65-66 for more information about non-IFRS measures.
[2] Net profit after tax attributable to equity holders of the parent.
[3] The global operations effective income tax rate (EITR) is ~33%. The EITR is calculated as the Group's income tax expense divided by profit before income tax. EITR for H1 2021 is ~39%
[4] H1 2021 comparative has been restated due to the reclassification of purchases of shares and payments relating to employee share plans from cash flows from operating to financing activities.
[5] Excludes exploration capitalised and the benefit of Global Infrastructure Partners' (GIP) additional contribution to Pluto Train 2.
[6] Excludes prior period expenditure written off and permit amortisation and includes evaluation expense.
[7] Cash flow from operating activities and cash flow from investing activities.
[8] Comparisons are to half-year ended 30 June 2021.

Net profit after tax reconciliation

The following table summarises the variance between the H1 2021 and H1 2022 results for the contribution of each line item to net profit after tax (NPAT).

2021 H1 reported NPAT	**$317 million**	
Sales revenue – price	+$2,482 million	Higher realised prices across all markers
Sales revenue – volume	+$820 million	Increased volume due to contribution of BHP Petroleum assets and Interconnector volumes
Movement in onerous contract provision	+$195 million	Derecognition and unwind of the Corpus Christi onerous contract provision
Other income	+$474 million	Primarily sale of 49% of the Pluto Train 2 Joint Venture
Cost of production	-$309 million	Increased royalties and excise due to higher revenue
Trading costs	-$435 million	Higher prices but fewer cargoes traded
General, administrative and other costs	-$474 million	Primarily due to merger transaction costs
Other expenses	-$343 million	Primarily losses associated with hedging
Income tax and PRRT	-$1,087 million	Increased taxes due to higher revenue
2022 H1 reported NPAT	**$1,640 million**	
2022 H1 NPAT adjustments	+$179 million	Adjustment for merger transaction costs and derecognition of the Corpus Christi onerous contract provision
2022 H1 underlying NPAT	**$1,819 million**	

Capital management

Interim dividend

Woodside's capital management framework is focused on disciplined capital management to optimise value and shareholder returns through the cycle. A 2022 interim fully franked dividend of 109 US cents per share (cps) has been declared, reflecting Woodside's strong operational performance and the contribution of BHP's petroleum business from the merger effective date of 1 July 2021.

The interim dividend comprises:

- 76 US cps, being an 80% payout of underlying NPAT, which is at the top end of Woodside's target range of 50% to 80%
- 33 US cps, being 80% of the net cash payment received from BHP following completion of the merger, adjusted for a minimum working capital requirement.

The value of the interim dividend payment is $2,070 million.

Dividend reinvestment plan

The dividend reinvestment plan (DRP) remains active, allowing eligible shareholders to reinvest their dividends directly into shares. The discount has been reduced to nil and Woodside intends to purchase on-market the shares to be distributed under the DRP. To the extent that the on-market purchase is not able to be completed for any reason, Woodside may issue new ordinary shares to meet its obligation under the DRP. Eligible shareholders have until 12 September 2022 to change their DRP election.[9] The DRP Rules were

[9] Eligibility is addressed in the DRP Rules. A Shareholder is not eligible to participate in the DRP if they are a "U.S. person" (as defined in Regulation S under the U.S. Securities Act of 1933), or if they are representing the estate of any deceased person where Woodside has been notified of the estate.

amended with effect from 30 August 2022. A copy of the revised DRP Rules is available on Woodside's website www.woodside.com/investors/dividends/dividend-reinvestment-plan.

Liquidity and debt service

During the half, Woodside generated $2,523 million of cash flow from operating activities and delivered positive free cash flow of $2,568 million.

Woodside increased its standby debt facilities from $3,100 million to $3,300 million and refinanced near-term maturities. Liquidity at the end of the period was $7,915 million and Woodside's drawn debt at the end of the period was $5,404 million. Woodside will continue to actively manage its debt portfolio throughout 2022.

Credit rating management

Woodside's gearing at the end of 2021 was 21.9%, within our target range of 15% to 35%. The merger transaction was on a debt-free basis and on completion Woodside issued 914,768,948 new shares. The increase in equity, increased cashflows and immaterial change in debt resulted in Woodside's gearing reducing to 6.8% at the end of H1 2022.

Given the structural changes to Woodside's balance sheet, management has reviewed the target balance sheet metrics and determined that a target gearing range of 10% to 20% through the cycle is appropriate for the scale and financial strength of the new organisation. Following the distribution of the 2022 interim dividend, gearing is expected to increase to approximately 13%, which is within the new target range.

A low level of net debt positions Woodside's balance sheet for the significant capital expenditure program ahead and is designed to protect against external volatility through the investment cycle. As a result, Woodside's gearing may at times fall outside the target range of 10% to 20% as the balance sheet is managed through the investment cycle. Woodside's estimated capital expenditure for the Scarborough, Pluto Train 2 and Sangomar projects from 1 July 2022 to 31 December 2024 is approximately $9 billion at current equity levels.[10]

Woodside's commitment to an investment grade credit rating remains unchanged and supports Woodside's aim of providing sustainable returns to shareholders and to investing in future growth opportunities, in accordance with the capital allocation framework.

During the half, our credit ratings of BBB+ and Baa1 were both reaffirmed by S&P Global and Moody's respectively.[11]

Commodity price risk management

Woodside strategically hedges to protect the balance sheet against downside commodity price risk, particularly during periods of high capital expenditure.

As at 30 June 2022, Woodside has placed oil price hedges for:

- approximately 17.5 MMboe of 2022 production at an average price of $74.6 per barrel of which approximately 5.8 MMboe has been delivered
- approximately 21.8 MMboe of 2023 production at an average price of $74.5 per barrel.

Woodside has also placed a number of hedges for Corpus Christi LNG volumes to protect against downside pricing risk. These hedges are Henry Hub and Title Transfer Facility (TTF) commodity swaps. As a result of hedging and term sales, approximately 94% of Corpus Christi volumes in 2022, approximately 73% in 2023 and approximately 27% of 2024 have reduced pricing risk (as at 30 June 2022).

Woodside and BHP Petroleum merger

The merger of Woodside and BHP's petroleum business completed on 1 June 2022 following Woodside shareholder approval on 19 May 2022.

On completion, Woodside acquired the entire share capital of BHP Petroleum International Pty Ltd (BHPP) and issued 914,768,948 new Woodside shares to BHP. Woodside received net cash of approximately $1.1 billion, which included the cash remaining in BHPP bank accounts of $399 million immediately prior to

[10] Indicative only, not guidance. Excludes the benefit of the additional capital contribution by GIP for Pluto Train 2.
[11] A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time.

completion. All completion payments are subject to a customary post-completion review which may result in an adjustment.

Trading commenced on 2 June 2022 under the ticker WDS of the new Woodside shares on the Australian Securities Exchange (ASX), and Woodside depository shares on the New York Stock Exchange (NYSE).

Trading commenced on 6 June 2022 of Woodside shares on the Main Market for listed securities of the London Stock Exchange (LSE), also under the ticker WDS.

The proposed appointment of a BHP director to the Board of Woodside following completion of the merger has been reviewed by both Woodside and BHP and is not considered necessary.

Woodside has delivered synergies of approximately $100 million of the $400+ million per year synergies target, with more than $300 million of further opportunities for synergies identified.[12]

Operational overview

Pluto LNG

Pluto LNG is an LNG facility in the Pilbara region of Western Australia, comprising an offshore platform and one onshore LNG processing train. Woodside is operator and holds a 90% participating interest.

Woodside achieved strong production performance at Pluto LNG, delivering 24.3 MMboe production (Woodside share) in the first half of 2022. This was an 11% increase compared to the first half of 2021 due to the start-up of the first phase of the Pyxis Hub and the Pluto-Karratha Gas Plant Interconnector, enabling Pluto gas to be processed at the Karratha Gas Plant (KGP).

The tenth anniversary of the first LNG produced at Pluto occurred in May 2022. The project also delivered its 700th cargo in June 2022. The sale of LNG and condensate produced at Pluto LNG in the past decade has generated approximately $23 billion in revenue for Woodside.

Preparatory siteworks and installation of high-voltage cable were undertaken to support the potential future use of imported lower-carbon electricity in Pluto LNG operations.

The Pyxis Hub infill campaign involves the subsea tie-back of the Pyxis, Pluto North and Xena fields to the Pluto offshore platform. The Pyxis and Pluto North wells commenced operations in January 2022, increasing offshore deliverability and enabling the delivery of Pluto gas to North West Shelf through the Pluto-KGP Interconnector. The Xena-02 well is on track to achieve ready for start-up (RFSU) in the second half of 2022.

North West Shelf Project

The North West Shelf Project (NWS) is one of Australia's largest resources projects and includes three offshore platform hubs and five onshore LNG processing trains. It produces LNG, condensate, pipeline gas and natural gas liquids (NGLs). Woodside is operator and holds a 33.33% participating interest.

Woodside's share of production was 13.1 MMboe. This was a 1% decrease compared to H1 2021 due to natural field decline and planned maintenance, partially offset by the start-up of Greater Western Flank Phase 3 (GWF-3) and the contribution of Woodside's increased participating interest in June.

A major turnaround was successfully completed on LNG Train 3 at KGP in May 2022.

The GWF-3 infill project achieved RFSU in April 2022 and the Lambert Deep infill well achieved RFSU in July 2022. Both projects were delivered ahead of schedule and under budget.

Tolling operations commenced at the NWS Project in March 2022 with the processing of gas delivered from Pluto through the Pluto-KGP Interconnector. The first LNG cargo produced from gas delivered through the Interconnector was loaded in April 2022. This is the first example of KGP processing gas owned by other resource owners, utilising spare capacity for LNG and domestic gas production. The NWS Project is also expected to commence processing Waitsia gas from 2023.

With the additional gas supplied from GWF-3, Lambert Deep and through the Interconnector, KGP is expected to operate near full production rates for the remainder of 2022.

The Western Australian Environmental Protection Authority (EPA) recommended in June 2022 that the NWS Project Extension proposal may be implemented subject to key environmental conditions being met. The proposal supports the long-term operations and processing of future third-party gas resources. The EPA's

[12] Delivered synergies of $100 million is on a pre-tax 100% basis and excludes transition and separation costs.

report is subject to a statutory appeals process before the Western Australian Minister for the Environment makes a decision on the proposal.

Wheatstone and Julimar-Brunello

Wheatstone is an LNG processing facility near Onslow, Western Australia, comprising an offshore production platform and two onshore LNG production trains. It processes gas from several offshore gas fields including Julimar and Brunello. Woodside holds a 13% non-operating interest in the Wheatstone project; and a 65% participating interest in the Julimar-Brunello fields, for which Woodside is operator.

Woodside's share of production was 5.2 MMboe. This was a decrease from the 7.4 MMboe produced in the first half of 2021, driven predominantly by planned onshore and offshore turnaround activity which was completed in the first half of 2022.

The Julimar-Brunello Phase 2 project, which included the tie-back of the Julimar field to the Wheatstone platform, achieved steady-state operations in March 2022.

Australia Oil

Woodside operates three floating production storage and offloading (FPSO) facilities off the north-west coast of Western Australia – the Okha FPSO (Woodside interest: 50%), Ngujima-Yin FPSO (Woodside interest: 60%) and Pyrenees FPSO (Woodside interest: 40% in WA-43-L and 71.4% in WA-42-L). The Pyrenees FPSO was added to Woodside's portfolio on 1 June 2022 on completion of the merger.

Woodside's share of production from the Okha FPSO, which produces oil from the Cossack, Wanaea, Lambert and Hermes fields, was 0.9 MMboe compared to 0.6 MMboe in H1 2021.

Woodside's share of production from the Ngujima-Yin FPSO, which produces oil from the Vincent and Greater Enfield resources, was 3.7 MMboe. This was 12% higher compared to the first half of 2021 due to the impact on production of Tropical Cyclone Seroja in H1 2021 and increased production rates when the Cimatti field oil and water injection wells were brought back online in March 2022.

Woodside's share of production from the Pyrenees FPSO, which produces oil from the Crosby, Ravensworth, Stickle, Wildbull, Tanglehead and Moondyne fields, was 0.2 MMboe in June 2022.

Macedon

Macedon produces pipeline gas for the Western Australian domestic gas market and was added to Woodside's portfolio on 1 June 2022. Gas is piped from a field located off the coast of Exmouth, Western Australia, to an onshore gas treatment plant located near Onslow, Western Australia. Woodside is operator and holds a 71.4% participating interest. Woodside's share of production was 0.7 MMboe in June 2022.

Bass Strait

The Gippsland Basin Joint Venture (GBJV) produces gas and oil from the Bass Strait in the south-east of Australia and was added to Woodside's portfolio on 1 June 2022. Gas produced by the GBJV is supplied into the eastern Australian domestic gas market.

Woodside holds a 50% non-operating interest in the GBJV and a 32.5% non-operating interest in the Kipper Unit Joint Venture. Kipper unit production is processed by the GBJV under a processing agreement. Woodside's share of production from the Bass Strait was 3.3 MMboe in June 2022.

An offshore fuel gas pipeline was redirected in June 2022 to increase production capacity from 970 terajoules to 1,020 terajoules per day (100%). This enabled Woodside to supply additional gas into the eastern Australian domestic gas market.

The GBJV is progressing a feasibility study of the potential development of a south-east Australian carbon capture and storage hub (SEA CCS) to support the decarbonisation goals of the GBJV participants, other local industry, and the Victorian and Commonwealth Governments. SEA CCS aims to utilise existing infrastructure to capture and store up to 2 $MtCO_2$ per year in the depleted Bream reservoir located offshore Victoria.

In August 2022, the GBJV executed a long-term supply agreement with BOC for the supply of carbon dioxide (CO_2) from the GBJV's Longford Gas Conditioning Plant. The CO_2 will be captured and transformed into products for the food, beverage, hospitality, manufacturing and medical industries through an adjacent treatment facility to be constructed by BOC.

Atlantis

Atlantis is a conventional oil and gas development and is one of the largest producing fields in the US Gulf of Mexico (GoM). Atlantis was added to Woodside's portfolio on 1 June 2022 and Woodside holds a 44% non-operating interest. The Atlantis development includes a semi-submersible facility with 26 active producer wells and two water injector wells. Oil and gas from the field is transported onshore through existing pipeline infrastructure, including the Caesar and Cleopatra pipelines in which Woodside has a participating interest.

Woodside's share of production from Atlantis was 1.1 MMboe in June 2022. Ocean bottom node (OBN) seismic acquisition was completed in June 2022, supporting optimisation of future development opportunities. A planned seven-week turnaround was completed in August 2022.

Mad Dog

Mad Dog is a conventional oil and gas development located in the US GoM and was added to Woodside's portfolio on 1 June 2022. The Phase 1 development includes a spar facility with drilling capability and 10 active producer wells. Further drilling operations are in progress, with an 11th producing well underway and three additional wells or side tracks planned. Oil and gas from the field is transported onshore through existing pipeline infrastructure, including the Caesar and Cleopatra pipelines. Woodside holds a 23.9% non-operating interest in Mad Dog.

Woodside's share of production from Mad Dog was 0.4 MMboe in June 2022. OBN seismic acquisition is in progress to inform subsequent development phases.

Shenzi

Shenzi is a conventional oil and gas field developed through a tension leg platform (TLP) located in the US GoM. It was added to Woodside's portfolio on 1 June 2022. The field has 16 active producer wells and five water injector wells. Crude oil is transported to connecting pipelines for sale to Gulf coast customers. Natural gas is transported onshore through a lateral pipeline tied into the Cleopatra natural gas pipeline.

Woodside is operator for Shenzi and holds a 72% participating interest. Woodside's share of production from Shenzi was 0.8 MMboe in June 2022. A side track development well was brought online in July 2022, increasing field production rates. A subsea multi-phase pump was installed and commissioned ahead of schedule during a planned Shenzi TLP shutdown in April-May 2022, and is expected to improve recovery from existing producing wells and future infill wells.

Shenzi North is a two-well subsea tieback to the Shenzi TLP. Drilling of the second development well commenced in July 2022. The Shenzi North project is targeting first oil in 2024 following drilling and completion activities and installation of subsea equipment.

Greater Angostura

Greater Angostura includes the Angostura and Ruby conventional oil and gas fields, located offshore Trinidad and Tobago (T&T). It was added to Woodside's portfolio on 1 June 2022. The development includes an offshore central processing facility and five well head platforms. Oil and gas is exported to shore for sale. Woodside is operator and holds a 45% participating interest in the Angostura field and a 68.5% participating interest in the Ruby field. Woodside's share of production from Greater Angostura was 1.0 MMboe in June 2022.

Projects

Scarborough and Pluto Train 2

The Scarborough field is located approximately 375 km off the coast of Western Australia. The development will include a floating production unit (FPU), eight wells drilled in the initial phase and 13 wells drilled over the life of the Scarborough field, a trunkline to shore and new onshore infrastructure.

Expansion of the onshore Pluto LNG facility will include the construction of a second LNG train (Pluto Train 2), associated domestic gas processing facilities and supporting infrastructure and modifications to Pluto Train 1. A final investment decision (FID) was taken in November 2021. Woodside is operator and has a 100% participating interest in Scarborough and a 51% participating interest in Pluto Train 2. The sale to Global Infrastructure Partners (GIP) of a 49% non-operating participating interest in the Pluto Train 2 Joint Venture was completed in January 2022.

The Scarborough and Pluto Train 2 projects are progressing with all major equipment items procured, including compressors, generators and turbines. Fabrication of the FPU topsides has commenced, pipeline manufacturing was 25% progressed as of 30 June and fabrication of the subsea trees for the initial development phase is complete. Pluto Train 2 construction works have commenced.

Woodside is working with its key contractors to maximise local content and Indigenous contracting opportunities.

Front-end engineering design (FEED) activities for Pluto Train 1 modifications continued on schedule during the first half of 2022.

Approval was granted in April 2022 by the Commonwealth-Western Australian Joint Authority for the Scarborough Field Development Plan, enabling commencement of petroleum recovery operations from Petroleum Production Licences WA-61-L and WA-62-L. Woodside received government approval to construct and operate the Scarborough pipeline in Commonwealth and State waters.

Approval was granted in June 2022 to increase the diameter of the Scarborough trunkline within State waters from 32 inches to 36 inches. Assessment by regulators of secondary environmental approvals continues for offshore execution activities.

The sell-down process for equity in the Scarborough Joint Venture is progressing. Woodside is targeting first LNG cargo in 2026.

Sangomar Field Development Phase 1

The Sangomar Field Development Phase 1 is Senegal's first offshore oil project and includes a stand-alone FPSO, 23 wells and supporting subsea infrastructure. It is designed to allow the tie-in of subsequent phases. Woodside is operator and has an 82% participating interest in the project. The project was 63% complete at 30 June 2022.

Key work scopes completed for the FPSO in the first half of 2022 included final dry dock activities for the facility and installation of the external turret. The FPSO conversion activities were disrupted by COVID restrictions at several construction yards in the first half of 2022. As a result, the FPSO is expected to be moved during Q4 2022 from China to the Keppel Shipyard in Singapore to complete the topside integration and commissioning.

In Senegal, installation of the mooring system for the FPSO in the Sangomar field was successfully completed in July 2022. In August 2022, the subsea installation campaign commenced in the field and the majority of the subsea equipment manufacturing was completed. The 23-well development drilling campaign is progressing and the second drillship, the Ocean BlackHawk, commenced drilling in July 2022.

Confirmation was received from the Government of Senegal that a two-year exploration period extension has been granted for the Production Sharing Contract (PSC) area covering SNE North-Spica in March 2022 and an appraisal well is planned in H2 2022.

Woodside has ended the current sell-down process for Sangomar. Woodside is targeting first oil in the second half of 2023.

Mad Dog Phase 2

Mad Dog Phase 2 is a development of the southern flank of the Mad Dog field and includes the installation of a new floating production facility, Argos, with production capacity of up to 140,000 gross barrels of oil equivalent per day (Woodside interest: 23.9%). The hook-up and commissioning program of the Argos platform topsides is proceeding, and a successful drilling campaign is nearing completion. An issue with two of the production flexible joints was detected during testing. This is being assessed and an update on whether the expected project start-up in 2022 is impacted will be provided in due course.

Development activities

Trion

Trion is a greenfield oil and gas opportunity in the Mexican waters of the western Gulf of Mexico. The Trion field is located in a water depth of 2,500 m approximately 180 km off the Mexican coastline and 30 km south of the US/Mexico maritime border. The Trion development would be Mexico's first deepwater oil development. Woodside is operator and has a 60% participating interest.

Trion is a large field with unrisked 2C contingent resources of 536 MMboe 100% (Woodside share: 321.6 MMboe), with 88% being oil.

Trion is a proposed 24 well subsea development connected to a FPU capable of producing and transferring 100,000 barrels of oil per day to a floating storage and offloading (FSO) vessel, from where the oil will be transported to markets. Produced gas will primarily be injected into the reservoir for enhancing recovery and excess gas will be transported by a pipeline. By using new technologies and optimising operating practices, Trion carbon emissions are expected to be lower than industry average for this type of deepwater development (<15 $kgCO_2e$/boe compared to industry average of 20 $kgCO_2e$/boe).

A six-penetration appraisal program was completed in 2021. Trion was approved to move into FEED in August 2021 and the FEED studies were completed in June 2022. Due to volatility in the supply chain and market, the project team is re-assessing the best contracting strategies and engaging with contractors with the objectives of increasing predictability of cost and schedule ahead of a potential FID in 2023. Woodside and PEMEX are actively collaborating on finalising the field development plan to support this decision.

Wildling

Wildling was a two-well tieback opportunity to the Shenzi TLP in the central GoM. Drilling of an appraisal well was completed in July 2022 and sub-commercial quantities of hydrocarbons were encountered. The well was plugged and abandoned, and Woodside does not plan to pursue any further Wildling development activities in Blocks GC564 or GC520.

Browse

The Browse development comprises the Calliance, Brecknock and Torosa gas and condensate fields located approximately 425 km north of Broome, Western Australia. Woodside is operator and holds a 30.6% participating interest.

Commercial discussions and technical studies, along with title and primary environmental approvals, are being progressed in support of the Browse to NWS development concept.

Carbon management is a key focus for the development and a carbon capture and storage (CCS) concept is being evaluated. In August, Woodside was awarded a greenhouse gas assessment permit over the Calliance field.

Calypso

Calypso is located in Trinidad and Tobago, approximately 220 km off the coast of Trinidad, and comprises several gas discoveries in Block 23(a) and Block TTDAA 14. Woodside is operator and holds a 70% participating interest. Two appraisal wells were drilled in 2021 to delineate the resource and provide information for development studies. Appraisal results are being assessed in conjunction with conceptual engineering studies.

Sunrise

The Sunrise development comprises the Sunrise and Troubadour gas and condensate fields which are located approximately 450 km north-west of Darwin and 150 km south of Timor-Leste. Woodside is operator and holds a 33.44% participating interest. The Sunrise Joint Venture participants continue to engage the Australian and Timor-Leste Governments on a new Greater Sunrise PSC, which is required under the 2019 Maritime Boundary Treaty. In the first half of 2022, two PSC trilateral meetings were held with the Australian and Timor-Leste Governments with further meetings anticipated in the second half of 2022.

Exploration

Woodside is participating in the non-operated Starman-1 well, which is currently drilling in the US Gulf of Mexico. Woodside is also planning to drill the operated Hoodoo prospect in the western Gulf of Mexico in the second half of 2022 with co-owner Oxy, which acquired a 30% working interest in the Hoodoo-1 exploration well and 28 blocks around the prospect via a farm-down agreement executed in August 2022.

In the western US Gulf of Mexico, a lease exchange agreement was executed with Shell in April 2022, swapping working interest on multiple lease blocks to create two hubs; one Woodside-operated (Woodside interest 60%) and one Shell-operated (Woodside interest 40%).

In Barbados, a farm-out agreement with Shell was signed in March 2022 to assign a 40% interest in two offshore exploration licences for the Bimshire and Carlisle Bay Blocks. The agreement is subject to customary regulatory approvals and third-party consents and completion is targeted for H2 2022.

Woodside and operating partner, TotalEnergies, have completed a joint farm-down of a 30% working interest in block Marine XX in the Congo to Petronas. This was effective 27 July 2022 and Woodside's working interest is now 22.5%.

Seismic surveys were completed offshore northern Australia (2D Galactic Marine Seismic Survey) in May 2022 and in the Egyptian Red Sea Blocks 3 and 4 in July 2022.

New energy and technology

Woodside is intending to thrive through the energy transition and has set a target to invest $5 billion in new energy products and lower-carbon services by 2030, in alignment with Woodside's capital allocation framework.[13] In support of this strategy a range of opportunities are being progressed.

H2OK

H2OK is a proposed liquid hydrogen project in the Westport Industrial Park, Ardmore, Oklahoma. Woodside is operator and holds a 100% interest. Phase 1 involves construction of an initial 290-megawatt (MW) facility, producing up to 90 tonnes per day (tpd) of liquid hydrogen through electrolysis, initially targeting the heavy transport sector.

FEED commenced in January 2022, with award of contracts for electrolysis and liquefaction equipment packages pending. Woodside is actively marketing hydrogen offtake and is advancing a number of agreements in support of a targeted final investment decision in 2023. Further FEED activities will mature the integrated facility design, cost and schedule.

H2Perth

H2Perth is a proposed world-scale liquid hydrogen and ammonia production facility in Perth, Western Australia. The development concept has been updated to increase ammonia production in the initial phase from 0.6 Mtpa to 0.84 Mtpa. Environmental studies continue, including assessment of flora and fauna, greenhouse gas management, heritage, groundwater sampling, discharge modelling, air, noise, emissions management, traffic modelling and visual impact. A pre-FEED contract was awarded to McDermott in May 2022. Woodside holds a 100% interest in H2Perth and is targeting FID in 2024.

Hydrogen Refueller @H2Perth

Woodside is advancing plans for a proposed self-contained hydrogen production, storage and refuelling station, located in the Rockingham Industry Zone in Western Australia. Subject to necessary commercial agreements and regulatory approvals, Woodside is targeting start-up of the Hydrogen Refueller @H2Perth in 2024.

H2NZ and H2TAS

Woodside has been selected as one of two companies to enter final stage negotiations to become the lead developer of the Southern Green Hydrogen project in Southland, New Zealand. Southern Green Hydrogen is a joint project by Meridian Energy and Contact Energy.

H2TAS is a proposed renewable ammonia and hydrogen production facility in the Bell Bay area of northern Tasmania. The development concept would utilise a combination of wind and hydroelectric power.

Heliogen

Heliogen and Woodside entered into a project agreement in March 2022 to deploy a 5 MWe module of Heliogen's AI-enabled concentrated solar energy technology in California. In the first half of 2022, Woodside

[13] Individual investment decisions are subject to Woodside's investment hurdles. Not guidance. Potentially includes both organic and inorganic investment.

has contributed approximately $11 million to this project. Heliogen and Woodside have also signed a collaboration agreement to jointly market Heliogen's renewable energy technology in Australia.

Heliogen has established a facility in California to manufacture the solar reflectors and other components required for the 5 MWe module.

Woodside Solar Project

Woodside is progressing the proposed Woodside Solar Project, a solar facility which would initially generate electricity from a large-scale solar photovoltaic farm, complemented by a battery energy storage system.

Negotiations are advancing with key stakeholders and potential industrial customers aiming to integrate renewable energy in their operations.

Carbon management

Woodside continues to grow its portfolio of offsets and carbon origination projects, while also progressing several CCS opportunities across Australia. In addition to its involvement in the south-east Australia CCS hub, Woodside was awarded two greenhouse gas assessment permits by the Australian Department of Industry, Science, Energy and Resources. These permits enable potential CCS in the Browse Basin (operated) and the Bonaparte Basin (non-operated).

Carbon capture and utilisation (CCU)

Woodside launched a CCU collaboration with US-based technology developers ReCarbon and LanzaTech in March 2022. The companies are investigating the viability of a potential CCU pilot facility in Perth, Western Australia.

A term sheet was agreed in May 2022 between Woodside and the Eastern Metropolitan Regional Council (EMRC) for a proposed option to lease land. The option would provide for use of EMRC's Red Hill Waste Management Eco Park near Perth for a pilot CCU facility, and for the supply of landfill gas by EMRC to Woodside.

Woodside agreed in July 2022 to invest $9.9 million in String Bio Private Limited (String Bio), the developer of a patented process for recycling greenhouse gases into products such as livestock feed. The investment is subject to conditions precedent. Woodside and String Bio entered a strategic development agreement to explore opportunities for the potential commercial scale-up of String Bio technology.

Technology

Woodside committed A$10 million in financial and in-kind support in April 2022 to Curtin University in Perth, Western Australia after it was selected by the Australian Government to receive funding as part of the Trailblazer University Program. Together, Woodside and the Government are supporting the development of a research commercialisation hub for resources technologies, such as hydrogen and critical minerals. This aligns with Woodside's focus on innovative solutions and the new technology to support industry needs.

Environmental, Social and Governance (ESG)

Climate

Woodside released its Climate Report 2021, which outlines its response to climate change and strategy to thrive through the energy transition as a low-cost, lower-carbon energy provider. The report is structured to align with the Task Force on Climate-Related Financial Disclosures (TCFD) recommendations framework. Woodside continues to engage with shareholders and other stakeholders on Woodside's climate strategy.

Woodside participated in the pilot Corporate Emissions Reduction Transparency (CERT) report in the first half of 2022, enabling Australia's Clean Energy Regulator (CER) to verify that at 31 December 2021, Woodside had made progress towards its goal of a 15% reduction in net equity scope 1 and 2 greenhouse gas emissions by 2025 against its 2016-2020 baseline.

Health, Safety and Environment (HSE)

Woodside experienced one Tier 2 loss of primary containment process safety event on the Goodwyn Alpha platform in the first half of 2022. This event was low impact with no harm to people or the environment.

The year-to-date total recordable injury rate was 1.81 per million work hours compared to 1.74 recorded for full-year 2021. Woodside's focus remains on understanding and addressing the gaps in our safeguards to improve our overall safety performance. Area specific safety improvement plans are being implemented by Woodside leaders and contractor partners.

Environmental performance remained strong in the first half of 2022, with zero significant environmental events.

ESG Rating

Woodside was recognised by Sustainalytics as an ESG Industry Top Rated Company in the first half of 2022.

Supporting local suppliers

Woodside increased its year-on-year value of awarded contracts to local and Indigenous suppliers, and increased visibility of sustainable contracting opportunities for our local and Indigenous suppliers to our operations and projects.

Woodside continues to work with its key Sangomar contractors to ensure opportunities are maximised for Senegalese people and suppliers, whilst meeting the requirements of in-country local content legislation.

Communities

Woodside released a report on progress made in the first year of its 2021-2025 Reconciliation Action Plan. The report highlighted areas for improvement but also noted the achievements in the areas of respect for culture and heritage, economic participation, further developing capability and capacity, and supporting Indigenous Voice.

Woodside's 2021 Social Contribution Impact Report was released in March 2022, demonstrating our commitment to creating positive outcomes in the community and progress against Woodside's primary and secondary Sustainable Development Goals.

Social impact assessments (SIA) are underway for Karratha and Roebourne in the north-west of Australia, and SIA planning activities have commenced for the H2Perth and H2TAS projects.

Principal risks and uncertainties

There are several risk factors or uncertainties that could result in a material effect on the company results over the next six months. These risks and uncertainties may occur as a result of Woodside's activities globally, including in connection with its operated (or non-operated) assets, and third parties engaged through the value chain.

The risks are not listed in any particular order.

Climate Change	Risks associated with the transition to a lower carbon economy, including that it may impact demand (and pricing) for oil, gas and its substitutes, the policy and legal environment for its production, Woodside's reputation and the operating environment
Social Licence to Operate (SLTO)	Risks associated with actual or alleged deviation from social or business expectations of ethical behaviour (including breaches of laws or regulations) and social responsibility (including environmental impact and community contribution), particularly as these expectations evolve
Growth	Risks associated with delivery of both major and complex multi-year execution project activities across multiple global locations with a reliance on third parties for materials, products and services
Operations	Risks associated with safety or major hazard events in connection with our activities or facilities, that may impact production performance. This may also include unanticipated or unforeseeable adverse events or our ability to respond, manage and recover from such events
Finance	Risks associated with the ability to capture value during periods of market volatility, and the impact of interest rate and foreign exchange fluctuations and inflation on expenditure
People and Culture	Risks associated with the ability to attract, retain, develop and motivate key employees to succeed and safeguard both current or future performance and growth
Digital and Cyber Security	Risks associated with adopting and implementing new technologies, whilst safeguarding our digital information and landscape (including from cyber threats) across our value chain
Integration	Risks associated with our ability to integrate systems and processes, capture synergies and deliver the value of the combined underlying businesses post-merger with BHP's petroleum business

Further information on Woodside's risks and how they are managed can be found on pages 51-54 of the Annual Report 2021.

Reserves and resources

Following completion of the merger with BHP's petroleum business on 1 June 2022, Woodside's Reserves as at 1 June 2022 increased to 2,339.6 MMboe Proved (1P) Reserves and 3,786.4 MMboe Proved plus Probable (2P) Reserves, with an increase in the Best Estimate (2C) Contingent Resources to 8,682.4 MMboe.

Woodside confirms there are no changes to reservoir outcomes compared to Woodside's most recent reserves statement issued in February 2022 (Reserves Statement). Instead, the changes in the estimates of Reserves and Contingent Resources from those reported in the Reserves Statement are due to the matters noted below, including changes in the basis used to define the volumes reported as Reserves and Contingent Resources and the inclusion of volumes added as a result of the merger.

Specifically:

- As Woodside is now listed on both the Australian Securities Exchange (ASX) and the New York Stock Exchange (NYSE), it is required to estimate and report its Proved (1P) Reserves in accordance with the United States Securities and Exchange Commission (SEC) regulations, which are also compliant with the Society of Petroleum Engineers Petroleum Resources Management System (SPE-PRMS) guidelines. The adjustment to convert Proved (1P) Reserves to SEC-compliant methods has resulted in reductions in the estimates of Proved (1P) Reserves for some assets. SEC-compliant Proved (1P) Reserves estimates use a more restrictive rules-based approach and are generally lower than estimates prepared solely in accordance with SPE-PRMS guidelines due to certain differences, including because the SEC-compliant Proved (1P) Reserves use specified commodity price assumptions, exclude probabilistic aggregation, use a narrower interpretation around unpenetrated sand bodies and fault blocks, and exclude cross-block volumes. The economic assumptions and pricing used to calculate the SEC-compliant Proved (1P) Reserves are as of 31 December 2021, although the Reserve base has been updated to reflect production during the period from 1 January 2022 to 31 May 2022.
- Woodside's Proved plus Probable (2P) Reserves and Best Estimate (2C) Contingent Resources continue to be estimated and reported in accordance with the SPE-PRMS guidelines.
- Woodside's Reserves and Contingent Resources are now reported inclusive of all fuel consumed in operations. Previously, Woodside's Reserves and Contingent Resources were reported net of the fuel consumed in operations up to the outlet of the floating production storage and offloading facility (FPSO) or platform (for offshore oil projects) or the inlet to the downstream (onshore) processing facility (for onshore gas projects).
- To achieve consistency between Woodside's reporting of production and reserves volumes, Woodside now uses 'natural gas', 'natural gas liquids' and 'oil/condensate' volumes categories, which are defined based on products. Previously, Woodside used 'dry gas' and 'condensate' volumes categories, which were defined based on composition.
- The barrel of oil equivalent (boe) conversion factor for natural gas remains unchanged at 5.7 Bcf per MMboe, the same conversion factor used previously for dry gas. Assets added as a result of the merger are now reported on this basis. Historically, BHP Petroleum used a boe conversion factor of 6.0 Bcf per MMboe.
- The effective date for the Reserves and Contingent Resources estimates stated in this Reserves and Resources Update is 1 June 2022, with estimates updated for production during the period from 1 January 2022 to 31 May 2022.

In addition:

- Woodside has transferred 12.6 MMboe Proved (1P) Reserves and 17.5 MMboe Proved plus Probable (2P) Reserves from Undeveloped to Developed as a result of achieving ready for start up (RFSU) of the GWF-3 Project.
- As identified in the Reserves Statement, the 109.5 MMboe Best Estimate (2C) Contingent Resource associated with the Myanmar A-6 opportunity has been removed.

Table 1: Woodside's Reserves[1,2,3,4,5] and Contingent Resources[6] overview (net Woodside share, as at 1 June 2022)

	Natural gas[7] Bcf[9]	Natural gas liquids[8] MMbbl[10]	Oil/condensate MMbbl	Total MMboe[11]
Proved[12] Developed[13] and Undeveloped[14]	**10,657.2**	**28.5**	**441.4**	**2,339.6**
Proved Developed	2,807.9	22.2	196.3	711.1
Proved Undeveloped	7,849.3	6.4	245.1	1,628.6
Proved plus Probable[15] Developed and Undeveloped	**17,051.9**	**48.6**	**746.3**	**3,786.4**
Proved plus Probable Developed	4,497.9	39.3	348.5	1,177.0
Proved plus Probable Undeveloped	12,554.0	9.2	397.8	2,609.4
Contingent Resources	**41,427.5**	**90.2**	**1,324.3**	**8,682.4**

Small differences are due to rounding.

243.3 MMboe of fuel consumed in operations included in Proved Developed and Undeveloped Reserves

382.7 MMboe of fuel consumed in operations included in Proved plus Probable Developed and Undeveloped Reserves

Table 2: Proved (1P) and Proved plus Probable (2P) Developed and Undeveloped Reserves reconciliation by product (net Woodside share, as at 1 June 2022)

	Natural gas Bcf		Natural gas liquids MMbbl		Oil/condensate MMbbl		Total MMboe	
	Proved (1P)	Proved plus Probable (2P)	Proved (1P)	Proved plus Probable (2P)	Proved (1P)	Proved plus Probable (2P)	Proved (1P)	Proved plus Probable (2P)
Reserves at 31 December 2021[16]	**8,090.7**	**11,669.4**	**0.0**	**0.0**	**172.9**	**244.4**	**1,592.3**	**2,291.7**
Revision of Previous Estimates[17]	-590.1	328.5	2.9	4.5	-34.1	0.9	-134.8	63.0
Transfer to/from Reserves[18]	-	-	-	-	-	-	-	-
Extensions and Discoveries[19]	-	-	-	-	-	-	-	-
Acquisitions and Divestments[20]	3,347.4	5,244.7	26.0	44.4	309.6	507.9	922.8	1,472.4
Production[21]	-190.7	-190.7	-0.3	-0.3	-6.9	-6.9	-40.7	-40.7
Reserves at 1 June 2022	**10,657.2**	**17,051.9**	**28.5**	**48.6**	**441.4**	**746.3**	**2,339.6**	**3,786.4**

Small differences are due to rounding.

Table 3: Best Estimate (2C) Contingent Resources reconciliation by product (net Woodside share, as at 1 June 2022)

	Natural gas Bcf	Natural gas liquids MMbbl	Oil/condensate MMbbl	Total MMboe
Contingent Resources at 31 December 2021	**34,768.0**	**0**	**499.7**	**6,599.4**
Revision of Previous Estimates[17]	1,471.4	8.3	0.4	266.8
Transfer to/from Reserves[18]	-	-	-	-
Extensions and Discoveries[19]	-	-	-	-
Acquisitions and Divestments[20]	5,188.1	81.9	824.1	1,816.3
Contingent Resources at 1 June 2022	**41,427.5**	**90.2**	**1,324.3**	**8,682.4**

Small differences are due to rounding.

Table 4: Proved (1P) Developed and Undeveloped[22] Reserves by region (net Woodside share, as at 1 June 2022)

Country	Asset	Natural gas Bcf			Natural gas liquids MMbbl			Oil/condensate MMbbl			Total MMboe		
		Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total
Australia	Greater Pluto[23]	997.0	311.7	1,308.7	0.0	0.3	0.3	12.7	3.9	16.6	187.6	58.9	246.5
	Bass Strait	421.3	34.2	455.5	14.6	1.4	16.0	8.9	1.0	9.8	97.3	8.4	105.7
	North West Shelf[24]	798.8	100.8	899.6	4.0	0.5	4.5	26.2	2.4	28.6	170.3	20.6	191.0
	Greater Exmouth[25]	0.0	0.0	0.0	0.0	0.0	0.0	13.5	0.0	13.5	13.5	0.0	13.5
	Pyrenees	0.6	0.0	0.6	0.0	0.0	0.0	9.7	1.7	11.4	9.8	1.7	11.5
	Macedon	224.3	65.0	289.3	0.0	0.0	0.0	0.0	0.0	0.0	39.4	11.4	50.8
	Julimar-Brunello[26]	157.0	122.0	279.0	0.0	0.0	0.0	2.6	2.1	4.7	30.1	23.5	53.6
	Greater Scarborough[27]	0.0	7,173.3	7,173.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,258.5	1,258.5
US GoM	Shenzi	18.5	4.8	23.3	1.1	0.9	2.0	49.6	15.4	65.0	54.0	17.1	71.1
	Shenzi North	0.0	4.7	4.7	0.0	1.0	1.0	0.0	14.7	14.7	0.0	16.5	16.5
	Atlantis	35.9	3.6	39.4	1.8	0.4	2.2	47.2	10.5	57.7	55.3	11.6	66.9
	Mad Dog	6.1	29.2	35.3	0.7	1.8	2.5	23.9	112.3	136.2	25.7	119.2	144.9
T&T	Angostura	117.3	0.0	117.3	0.0	0.0	0.0	1.2	0.0	1.2	21.7	0.0	21.7
	Ruby	31.2	0.0	31.2	0.0	0.0	0.0	0.8	0.0	0.8	6.3	0.0	6.3
Senegal	Sangomar[28]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	81.2	81.2	0.0	81.2	81.2
Total	**Reserves**	**2,807.9**	**7,849.3**	**10,657.2**	**22.2**	**6.4**	**28.5**	**196.3**	**245.1**	**441.4**	**711.1**	**1,628.6**	**2,339.6**

Small differences are due to rounding.

243.3 MMboe of fuel consumed in operations included in Proved Developed and Undeveloped Reserves

Table 5: Proved plus Probable (2P) Developed and Undeveloped Reserves by region (net Woodside share, as at 1 June 2022)

Country	Asset	Natural gas Bcf			Natural gas liquids MMbbl			Oil/condensate MMbbl			Total MMboe		
		Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	Total
Australia	Greater Pluto	1,393.1	339.3	1,732.4	0.3	0.1	0.4	19.3	4.4	23.7	264.0	64.0	327.9
	Bass Strait	655.7	54.3	710.0	23.0	1.9	24.8	14.5	1.5	16.0	152.5	12.9	165.5
	North West Shelf	1,404.1	149.5	1,553.6	7.3	0.2	7.6	46.8	3.6	50.4	300.4	30.1	330.5
	Greater Exmouth	0.0	0.0	0.0	0.0	0.0	0.0	22.4	0.0	22.4	22.4	0.0	22.4
	Pyrenees	0.6	0.0	0.6	0.0	0.0	0.0	17.9	3.2	21.1	18.0	3.2	21.2
	Macedon	297.0	40.2	337.2	0.0	0.0	0.0	0.0	0.0	0.0	52.1	7.1	59.2
	Julimar-Brunello	436.6	427.7	864.3	0.0	0.0	0.0	8.4	7.7	16.1	85.0	82.8	167.7
	Greater Scarborough	0.0	11,475.3	11,475.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,013.2	2,013.2
US GoM	Shenzi	25.6	6.8	32.4	2.2	1.2	3.4	71.5	21.8	93.3	78.3	24.2	102.5
	Shenzi North	0.0	10.2	10.2	0.0	2.1	2.1	0.0	32.1	32.1	0.0	36.0	36.0
	Atlantis	81.4	11.3	92.8	5.5	1.5	7.0	114.2	25.5	139.6	133.9	29.0	162.9
	Mad Dog	7.9	39.2	47.1	1.1	2.2	3.3	31.3	149.2	180.5	33.8	158.3	192.1
T&T	Angostura	148.9	0.0	148.9	0.0	0.0	0.0	1.2	0.0	1.2	27.3	0.0	27.3
	Ruby	47.1	0.0	47.1	0.0	0.0	0.0	1.1	0.0	1.1	9.3	0.0	9.3
Senegal	Sangomar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	148.7	148.7	0.0	148.7	148.7
Total	**Reserves**	**4,497.9**	**12,554.0**	**17,051.9**	**39.3**	**9.2**	**48.6**	**348.5**	**397.8**	**746.3**	**1,177.0**	**2,609.4**	**3,786.4**

Small differences are due to rounding.

382.7 MMboe of fuel consumed in operations included in Proved plus Probable Developed and Undeveloped Reserves

Table 6: Best Estimate (2C) Contingent Resources summary by region (net Woodside share, as at 1 June 2022)

Country	Asset	Natural gas Bcf	Natural gas liquids MMbbl	Oil/condensate MMbbl	Total MMboe
Australia	Greater Pluto	1,217.6	0.0	22.5	236.1
	Bass Strait	692.6	37.3	58.4	217.3
	North West Shelf	573.6	2.9	37.2	140.7
	Exmouth[29]	42.1	0.0	1.6	8.9
	Greater Exmouth	307.4	0.0	29.0	82.9
	Pyrenees	0.0	0.0	12.3	12.3
	Macedon	117.0	0.0	0.0	20.5
	Julimar-Brunello	39.4	0.0	0.7	7.6
	Greater Scarborough	1,631.4	0.0	0.0	286.2
	Greater Browse[30]	4,469.7	6.8	119.4	910.4
	Greater Sunrise[31]	1,778.0	0.0	75.6	387.5
	Stybarrow	0.0	0.0	1.6	1.6
US GoM	Shenzi	21.6	5.9	83.7	93.4
	Shenzi North	1.1	0.2	3.4	3.8
	Atlantis	211.7	32.3	155.1	224.5
	Mad Dog	40.3	1.0	148.6	156.7
	Wildling	17.6	3.7	56.3	63.0
T&T	Angostura	188.1	0.0	0.9	33.9
	Ruby	45.6	0.0	3.2	11.2
	T&T Deep Water	2,517.5	0.0	0.0	441.7
Mexico	Trion	215.4	0.0	283.8	321.6
Canada	Liard[32]	27,000.3	0.0	0.0	4,736.9
Senegal	Senegal	299.7	0.0	231.2	283.7
Myanmar	Myanmar	0.0	0.0	0.0	0.0
Total	**Resources**	**41,427.5**	**90.2**	**1,324.3**	**8,682.4**

Small differences are due to rounding.

Additional information for recently acquired assets

Woodside is reporting Reserves and Contingent Resources for the first time in respect of each of the assets recently acquired as part of the merger (other than the North West Shelf and Scarborough assets) (Recently Acquired Assets). A brief description of the Recently Acquired Assets, the Reserves and Contingent Resources associated with the Recently Acquired Assets and how the Reserves and Contingent Resources for the Recently Acquired Assets have been estimated is provided below.

The NWS and Scarborough assets are not described below as they have previously been reported by Woodside as a result of Woodside's interest in those assets prior to the merger. However, Woodside confirms that, as a result of the merger, Woodside's interest in the Scarborough assets increased from 73.5% to 100%, its interest in the NWS gas assets increased from 15% to 30%, and its interest in the NWS oil assets increased from 33.3% to 50%.

Reserves and Contingent Resources estimates shown are net of royalties owned by others and have been estimated using deterministic methodology. Reserves and Contingent Resources estimates have not been adjusted for risk. Unless noted otherwise, Reserves and Contingent Resources are as of the effective date of 1 June 2022 and are Woodside's net economic interest volumes.

Proved (1P) Reserves are estimated and reported on a net interest basis in accordance with the SEC regulations and have been determined in accordance with SEC Rule 4-10(a) of Regulation S-X. As defined by the SEC, Proved (1P) Reserves are those quantities of crude oil, natural gas and natural gas liquids that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs and under existing economic conditions, operating methods, operating contracts and government regulations. Unless evidence indicates that renewal of existing operating contracts is reasonably certain, estimates of economically producible Reserves reflect only the period before the contracts expire. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence within a reasonable time.

Proved (1P) Reserves were estimated by reference to available well and reservoir information, including but not limited to well logs, well test data, core data, production and pressure data, geologic data, seismic data and, in some cases, similar data from analogous, producing reservoirs. A wide range of engineering and geoscience methods, including performance analysis, numerical simulation, well analogues and geologic studies, have been used to develop high confidence Proved (1P) Developed and Undeveloped Reserves estimates for all of the assets described in this Reserves and Resources Update in accordance with SEC regulations.

Proved plus Probable (2P) Reserves and Best Estimate (2C) Contingent Resources are estimated in accordance with the SPE-PRMS guidelines. SPE-PRMS guidelines allow (amongst other things) escalations to prices and costs and, as such, volumes estimates in accordance with those guidelines would be on a different basis than volumes estimated as prescribed by the SEC. Proved plus Probable (2P) Reserves and Best Estimate (2C) Contingent Resources estimates are inherently more uncertain than Proved (1P) Reserves estimates.

Asset description: Bass Strait

Bass Strait is an offshore asset that consists of multiple oil and gas fields in the Gippsland Basin off the south eastern coast of Victoria, Australia. The project consists of an integrated network of offshore platforms and subsea tie-backs connected by extensive pipeline infrastructure to onshore processing facilities at Longford and Long Island Point.

The Bass Strait asset comprises the following joint ventures:

- Gippsland Basin Joint Venture – located in permits Vic/L1-L11 and Vic/L13-19. Ownership is 50% ExxonMobil (Operator) and 50% Woodside
- Kipper Unit Joint Venture – located in permits Vic/L9 and Vic/L25. Ownership is 32.5% ExxonMobil (Operator), 32.5% Woodside and 35% Mitsui. Kipper unit production is processed by the Gippsland Basin Joint Venture under a processing agreement.

Bass Strait has been in production since 1969. Natural gas produced from the fields is primarily sold domestically in eastern Australia. Crude oil and secondary natural gas liquid products (butane, propane and ethane) are sold at the onshore processing facilities and transported via pipelines, truck loading and export shipping. Undeveloped Reserves are primarily associated with the Kipper compression project which has a target RFSU in 2024.

Future development potential in this asset are primarily from unsanctioned contingent resources projects targeting deeper, acid gas resources. Several offshore facilities in the asset have ceased production after field depletion and programs for well abandonment, facility decommissioning and removal are currently ongoing.

Asset description: Exmouth, Stybarrow

The Exmouth asset comprises of Contingent Resources associated with gas discoveries at Scafell and oil discoveries at Skiddaw-Laverda in Western Australia. The Stybarrow asset comprises of minor Contingent Resources at the Stybarrow oil field. Cessation of production occurred in 2015.

The Scafell gas field is located approximately 120 km west of Onslow and 40 km north of Exmouth in the WA-43-L production licence. Ownership is 40% Woodside (Operator), 31.5% Santos and 28.5% Inpex.

Development plans have not been sanctioned for these assets and the Contingent Resource is carried in the SPE PRMS CR subclass of Development Currently Not Viable.

Asset description: Macedon

Macedon is an offshore gas field in Western Australia. It is located approximately 40 km north of Exmouth in the Exmouth subbasin in the WA-42-L production licence. Ownership is 71.4% Woodside and 28.6% Santos.

The project consists of subsea wells which are produced by pipeline to an onshore gas treatment plant near Onslow.

Macedon has been in production since 2013. Natural gas from the field is sold domestically in Western Australia. Undeveloped Reserves are associated with a compression project which is currently in execution.

Asset description: Pyrenees

Pyrenees is an offshore asset with six oil fields in Western Australia. It is located approximately 45 km northwest of Exmouth in the Carnarvon basin within the WA-42-L and WA-43-L production licences. Ownership is 71.4% Woodside (Operator) and 28.6% Santos in the WA-42-L licence and 40% Woodside (Operator), 31.5% Santos and 28.5% Inpex in the WA-43-L licence. The project consists of an FPSO, development wells to the Pyrenees oil fields and a well into the Macedon field that can inject or produce gas depending on facility requirements.

Pyrenees has been in production since 2010. Crude oil from the field is offloaded from the FPSO to tankers for international sale. Undeveloped Reserves are associated with infill wells to be drilled in 2023.

Asset description: Trion

Trion is an offshore oil and gas discovery in the Mexican waters of the western Gulf of Mexico. It is located approximately 180 km off the Mexican coast and 30 km south of the US/Mexico maritime border within Block AE-0092 and Block AE-0093. Ownership is 60% Woodside (Operator) and 40% Pemex. The field was discovered in 2012 and is currently being considered for development. No further appraisal wells are planned to be drilled and the field is under evaluation.

Development plans have not been sanctioned and the Contingent Resource is carried in the SPE PRMS CR subclasses of Development Pending and Development Unclarified.

Asset description: Angostura

Angostura is an offshore oil and gas asset in Trinidad and Tobago. It is located approximately 38 km off the northeast coast of Trinidad in Block 2(c). Ownership is 45% Woodside (Operator), 30% National Gas Company and 25% Chaoyang.

The Angostura field has been in production since 2005. Crude oil produced from the field is transported to the terminal facility on the south eastern coast of Trinidad for sale to international markets. Natural gas from the field is transported by pipeline and sold domestically to the National Gas Company.

Asset description: Ruby/Delaware

Ruby and Delaware are offshore oil and gas assets in Trinidad and Tobago. They are located in Block 3(a) and are adjacent to the Angostura asset. Ownership is 68.46% Woodside (Operator) and 31.54% National Gas Company.

The Ruby and Delaware fields have been in production since 2021. Production from these fields are transported by flow lines to the facilities on the Angostura asset for processing. Crude oil produced from these fields are transported to the terminal facility on the south eastern coast of Trinidad for sale to international markets. Natural gas from the fields is transported by pipeline and sold domestically to the National Gas Company.

Asset description: T&T Deep Water

T&T Deep Water comprises the gas discoveries in the Calypso and Magellan opportunities in offshore deepwater Trinidad and Tobago.

The Calypso opportunity is located approximately 217 km off the coast of Trinidad and comprises several gas discoveries in Block 23(a) and Block TTDAA 14. Ownership is 70% Woodside (Operator) and 30% BP. The initial discovery was made in 2018 and additional discoveries were made in subsequent years. Calypso is proximate to existing LNG infrastructure and downstream petrochemical facilities in Trinidad. The opportunity is currently being considered for development. Two appraisal wells were drilled in 2021 and the opportunity is under evaluation. Development plans have not been sanctioned and the Contingent Resource is carried in the SPE PRMS CR subclasses of Development Unclarified and Development Currently Not Viable.

The Magellan opportunity is located approximately 200 km east off the coast of Trinidad and comprises two gas discoveries in 2016 and 2018 in Block TTDAA 5. Ownership is 65% Woodside (Operator) and 35% Shell.

No further appraisal wells are planned and the opportunity is under evaluation. Development plans have not been sanctioned and the Contingent Resource is carried in the SPE PRMS CR subclass of Development Currently Not Viable.

Asset description: Atlantis

Atlantis is an offshore oil and gas asset in the US Gulf of Mexico. It is located approximately 210 km off the coast of Louisiana in the Green Canyon protraction area within the lease blocks C699, GC742, GC743, and GC744. Ownership is 56% BP (Operator) and 44% Woodside.

Future development opportunities in this field that will be leveraging existing infrastructure include:

- Atlantis Phase 3 project: In-fill development project with some wells already on production
- Multiple unsanctioned projects currently in planning phases.

Atlantis has been in production since 2007. Crude oil and natural gas produced from the field are transported by pipelines to the Gulf coast for sale.

Asset description: Mad Dog

Mad Dog is an offshore oil and gas asset in the US Gulf of Mexico. It is located approximately 200 km off the coast of Louisiana in the Green Canyon protraction area within the lease blocks GC738, GC781, GC782, GC824, GC825, GC826, GC868, GC869 and GC870. Ownership is 60.5% BP (Operator), 23.9% Woodside and 15.6% Chevron.

Future development opportunities in this field include:

- Mad Dog Phase 2 project: Sanctioned in 2017 to develop the southern flank of the field. The project is currently under execution
- Unsanctioned brownfield growth opportunities currently in planning phase.

Mad Dog has been in production since 2005. Crude oil and natural gas produced from the field are transported by pipelines to the Gulf coast for sale.

Asset description: Greater Shenzi

Greater Shenzi is an offshore oil and gas asset in the US Gulf of Mexico. It is located approximately 195 km off the coast of Louisiana in the Green Canyon protraction area. Greater Shenzi comprises:

- The currently producing Shenzi field located in lease blocks GC609, GC610, GC652, GC653 and GC654. Ownership is 72% Woodside (operator) and 28% Repsol
- Future tie-back developments at:
    - Shenzi North located in lease blocks GC608 and GC609. Ownership is 72% Woodside (Operator) and 28% Repsol and the project is currently under execution
    - Wildling located in lease blocks GC520 and GC564. Ownership is 100% Woodside and the project is currently under appraisal. Subsequent to 1 June 2022, the Wildling appraisal well SJ101 completed drilling activities and encountered sub-commercial quantities of hydrocarbons. Work is in progress to determine the subsequent revisions to the Contingent Resource estimates.

The Shenzi field has been in production since 2009. Crude oil and natural gas produced from the field are transported by pipelines to the Gulf coast for sale.

Governance and assurance

Woodside is an Australian company listed on the Australian Securities Exchange, the New York Stock Exchange and the London Stock Exchange. Woodside reports its Proved (1P) Reserves in accordance with SEC regulations, which are also compliant with SPE-PRMS guidelines, and prepares and reports its Proved plus Probable (2P) Reserves and Best Estimate (2C) Contingent Resources in accordance with SPE-PRMS guidelines. It reports all of its petroleum resource estimates using definitions 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) Petroleum Resources Management System (PRMS).

Woodside has several processes to provide assurance for reserves and contingent resources reporting, including the Woodside Reserves Policy, the Woodside Petroleum Resources Management Procedure, the Woodside Petroleum Resource Management Guideline, staff training and minimum competency levels and external reserves audits.

The Reserves and Contingent Resources reported for the Recently Acquired Assets were assured by Woodside in accordance with the process previously applied by the BHP Petroleum business. Each Reserve and Contingent Resource assessment is reviewed to ensure technical quality and compliance with SEC and SPE-PRMS reporting requirements (as applicable).

Unless otherwise stated, all petroleum resource estimates are quoted as net Woodside share at standard oilfield conditions of 14.696 pounds per square inch (psi) (101.325 kPa) and 60 degrees Fahrenheit (15.56 degrees Celsius).

Qualified petroleum reserves and resource evaluator statement

The estimates of petroleum resources for the Recently Acquired Assets are based on and fairly represent information and supporting documentation prepared under the supervision of Mr Abhijit Gadgil, Head of Petroleum Reserve Group (PRG), who is a full-time employee of the company and a member of the Society of Petroleum Engineers. Mr Gadgil's qualifications include a Master of Science (Chemical Engineering) from Rice University, Houston, Texas, and more than 40 years of relevant experience.

The estimates of petroleum resources for all other assets referenced in this Reserves and Resources Update (Woodside Heritage Assets) are based on and fairly represent information and supporting documentation prepared under the supervision of Mr Jason Greenwald, Woodside's Vice President Corporate Strategy, who is a full-time employee of the company and a member of the Society of Petroleum Engineers. Mr Greenwald's qualifications include a Bachelor of Science (Chemical Engineering) from Rice University, Houston, Texas, and more than 20 years of relevant experience.

Additional information for US investors

The SEC prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves" (as that term is defined by the SEC). In this report, Woodside includes estimates of quantities of oil and gas using certain terms, such as "Proved plus Probable (2P) Reserves," "Best Estimate (2C) Contingent Resources," "Reserves and Contingent Resources," "Proved plus Probable," "Developed and Undeveloped," "Probable Developed," "Probable Undeveloped," "Contingent Resources" or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC's guidelines strictly prohibit Woodside from including in filings with the SEC. These estimates 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, and accordingly are subject to substantially greater risk of being recovered by Woodside. In addition, actual locations drilled and quantities that may be ultimately recovered from Woodside's properties may differ substantially. Woodside has made no commitment to drill, and likely will not drill, all of the drilling locations that have been attributable to these quantities. U.S. investors are urged to consider closely the disclosures in Woodside's filings with the SEC, which are available at www.sec.gov.

Notes to the reserves and resources update

1. For offshore oil projects, the reference point is defined as the outlet of the floating production storage and offloading facility (FPSO) or platform, while for the onshore gas projects the reference point is defined as the outlet of the downstream (onshore) gas processing facility.
2. 'Reserves' are estimated quantities of petroleum that have been demonstrated to be producible from known accumulations in which the company has a material interest from a given date forward, at commercial rates, under presently anticipated production methods, operating conditions, prices and costs. Woodside reports Reserves inclusive of all fuel consumed in operations. Proved (1P) Reserves are estimated and reported in accordance with SEC regulations which are also compliant with SPE-PRMS guidelines. SEC-compliant Proved (1P) Reserves estimates use a more restrictive, rules-based approach and are generally lower than estimates prepared solely in accordance with SPE-PRMS guidelines due to, among other things, the requirement to use commodity prices based on the average price during the 12-month period in the reporting company's fiscal year. Proved plus Probable (2P) Reserves are estimated and reported in accordance with SPE-PRMS guidelines, and are not compliant with SEC regulations.
3. Assessment of the economic value of the Woodside Heritage Assets, in support of an SPE-PRMS (2018) reserves and resources classification, uses Woodside Portfolio Economic Assumptions (Woodside PEAs). The Woodside PEAs are reviewed on an annual basis or more often if required. The review is based on historical data and forecast estimates for economic variables such as product prices and exchange rates. The Woodside PEAs are approved by the Woodside Board. Specific contractual arrangements for individual projects are also taken into account.

4. Assessment of the economic value of the Recently Acquired Assets, in support of an SPE-PRMS (2018) reserves and resources classification, uses economic assumptions that were prepared and adopted by the BHP Petroleum business prior to the Merger (BHP Heritage Assumptions). The BHP Heritage Assumptions were prepared based on historical data and forecast estimates for economic variables such as product prices and exchange rates. Specific contractual arrangements for individual projects are also taken into account. Woodside is of the view that the BHP Heritage Assumptions form an appropriate basis for Woodside's evaluation of the Reserves and Contingent Resources for the Recently Acquired Assets. Woodside is of the view that there would be no material difference in the Reserve and Contingent Resource estimates for the Recently Acquired Assets reported in this Reserves and Resources Update had the Woodside PEAs been used instead of the BHP Heritage Assumptions.
5. Woodside uses both deterministic and probabilistic methods for the estimation of Reserves and Contingent Resources at the field and project levels. All Proved (1P) Reserves estimates have been estimated using deterministic methodology and reported on a net interest basis in accordance with the SEC regulations and have been determined in accordance with SEC Rule 4-10(a) of Regulation S-X. Unless otherwise stated, all petroleum estimates reported at the company or region level are aggregated by arithmetic summation by category. The aggregated Proved (1P) Reserves may be a conservative estimate due to the portfolio effects of arithmetic summation.
6. 'Contingent Resources' are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources are estimated and reported in accordance with SPE-PRMS guidelines and may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Woodside reports Contingent Resources inclusive of all fuel consumed in operations and net of non-hydrocarbons not present in sales products. Contingent Resources are different from, and should not be construed as, Reserves. Contingent Resources estimates may not always mature to Reserves and do not necessarily represent future Reserves bookings. Contingent Resource volumes are reported at the 'Best Estimate' (P50) confidence level. Best Estimate (2C) Contingent Resources are not compliant with SEC regulations. The SEC prohibits disclosure of oil and gas resources, including Contingent Resources, in SEC filings. However, Australian securities regulatory authorities allow disclosure of oil and gas resources, including Contingent Resources.
7. 'Natural gas' is defined as the gas product associated with liquefied natural gas (LNG) and pipeline gas. Liquid volumes of crude oil, condensate and NGLs are reported separately.
8. 'Natural gas liquids' or 'NGL' is defined as the product associated with liquified petroleum gas (LPG) and consists of propane, butane and ethane - individually or as a mixture.
9. 'Bcf' means Billions (10^9) of cubic feet of gas at standard oilfield conditions of 14.696 psi (101.325 kPa) and 60 degrees Fahrenheit (15.56 degrees Celsius).
10. 'MMbbl' means millions (10^6) of barrels of NGL, oil and condensate at standard oilfield conditions of 14.696 psi (101.325 kPa) and 60 degrees Fahrenheit (15.56 degrees Celsius).
11. 'MMboe' means millions (10^6) of barrels of oil equivalent. Natural Gas volumes are converted to oil equivalent volumes via a constant conversion factor, which for Woodside is 5.7 Bcf of dry gas per 1 MMboe. Volumes of NGL, oil and condensate are converted from MMbbl to MMboe on a 1:1 ratio.
12. 'Proved Reserves' are those quantities of crude oil, condensate, natural gas and NGLs that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs and under existing economic conditions, operating methods, operating contracts and government regulations. Proved Reserves are estimated and reported on a net interest basis in accordance with the SEC regulations and have been determined in accordance with SEC Rule 4-10(a) of Regulation S-X.
13. 'Developed Reserves' are those Reserves that are producible through currently existing completions and installed facilities for treatment, compression, transportation and delivery, using existing operating methods and standards.
14. 'Undeveloped Reserves' are those Reserves for which wells and facilities have not been installed or executed but are expected to be recovered through future investments.
15. 'Probable Reserves' are those Reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. Proved plus Probable (2P) Reserves represent the best estimate of recoverable quantities. Where probabilistic methods are used, there is at least a 50% probability that the actual quantities recovered will equal or exceed the sum of estimated Proved plus Probable (2P) Reserves. Proved plus Probable (2P) Reserves are estimated and reported in accordance with SPE-PRMS guidelines and are not compliant with SEC regulations.

16. 'Reserves at 31 December 2021' are estimated and reported in accordance with SPE-PRMS guidelines. Adjustments to convert Proved (1P) Reserves to SEC-compliant methods are included in 'Revisions of Previous Estimates' and reflected in 'Reserves at 1 June 2022'.
17. 'Revision of Previous Estimates' are revisions that represent changes (either upward or downward) in previous estimates of Reserves or Contingent Resources, which, for the purposes of this Reserves and Resources Update, reflect the changes in the basis used to define the volumes reported as Reserves and Contingent Resources as described in the introduction to this Reserves and Resources Update, including adjustments (i) to convert Proved (1P) Reserves to SEC-compliant methods; (ii) to include all fuel consumed in operations in Reserves and Contingent Resources; and (iii) to revise reporting categories to achieve consistency between Woodside's reporting of production and reserves volumes.
18. 'Transfer to/from Reserves' are revisions that represent changes (either upward or downward) in previous estimates of Reserves or Contingent Resources, which are a result of re-classification of petroleum resource estimates (i.e. from Reserves to Contingent Resources or vice versa) associated with one or more reference project(s).
19. 'Extensions and Discoveries' represent additions to Reserves or Contingent Resources that result from increased areal extensions of previously discovered fields demonstrated to exist subsequent to the original discovery and/or discovery of Reserves or Contingent Resources in new fields or new reservoirs in old fields.
20. 'Acquisitions and Divestments' are revisions that represent changes (either upward or downward) in previous estimates of Reserves or Contingent Resources, which result from either purchase or sale of interests and/or execution of contracts conveying entitlement, and, in this Reserves and Resources Update, includes volumes added as a result of the merger.
21. 'Production' is the volume of natural gas, NGLs, condensate and oil produced during the period from 1 January 2022 to 31 May 2022 and converted to 'MMboe' for the specific purpose of reserves reconciliation. The production volume figures in this Reserves and Resources Update differ from the production volume figures reported in Woodside's annual and quarterly reports, due to the fact that the production volume figures reported in this Reserves and Resources Update include all fuel consumed in operations, but exclude NWS domestic gas overlift volumes and Pluto Interconnector gas purchased in excess of Reserves and Resources working interest percentage.
22. Material concentrations of undeveloped reserves in the North West Shelf, Greater Pluto and Julimar-Brunello regions have remained undeveloped for longer than five years from the dates they were initially reported as the incremental reserves are expected to be recovered through future developments to meet long-term contractual commitments. The incremental projects are included in the company business plan, demonstrating the intent to proceed with the developments.
23. The 'Greater Pluto' region comprises the Pluto-Xena, Pyxis, Larsen, Martell, Martin, Noblige and Remy fields.
24. The 'North West Shelf' (NWS) region includes all oil and gas fields within the North West Shelf Project Area.
25. The 'Greater Exmouth' region comprises Vincent, Enfield, Greater Enfield, Greater Laverda, Ragnar and Toro fields.
26. The 'Julimar-Brunello' region comprises the Julimar and Brunello fields.
27. The 'Greater Scarborough' region comprises the Jupiter, Scarborough and Thebe fields.
28. The 'Senegal' region comprises the Sangomar field. The Developed and Undeveloped reserves comprise of oil estimates. The Best Estimate (2C) Contingent Resources include gas and oil estimates.
29. The 'Exmouth' region comprises Contingent Resources associated with gas discoveries at Scafell and oil discoveries at Skiddaw-Laverda.
30. The 'Greater Browse' region comprises the Brecknock, Calliance and Torosa fields.
31. The 'Greater Sunrise' region comprises the Sunrise and Troubadour fields.
32. The 'Liard' region comprises unconventional resources in the Liard Basin.

Governance

The directors of Woodside Energy Group Ltd present their report (including the review of operations set out on pages 1-25) together with the Financial Statements of the Group.

Board of directors

The names of directors in office during or since the end of the period are as follows:

Mr Richard Goyder, AO (Chairman)	Ms Meg O'Neill (CEO and Managing Director)
Mr Larry Archibald	Mr Frank Cooper, AO
Ms Swee Chen Goh	Dr Christopher Haynes, OBE
Mr Ian Macfarlane	Ms Ann Pickard
Dr Sarah Ryan	Mr Gene Tilbrook
Mr Ben Wyatt	

Rounding of amounts

The amounts contained in this report have been rounded to the nearest million dollars under the option available to the Group under Australian Securities and Investments Commission (ASIC) Instrument 2016/191 dated 24 March 2016, unless otherwise stated.

Management assurance

Consistent with recommendation 4.2 of the ASX Corporate Governance Council's Corporate Governance Principles and Recommendations (4th edition), before the adoption by the Board of the Half-Year Financial Statements 2022, the Board received written declarations from the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO) that the financial records of the company have been properly maintained in accordance with section 286 of the Corporations Act 2001, and the company's financial statements and notes comply with accounting standards and give a true and fair view of the consolidated entity's financial position and performance for the financial period. The CEO and the CFO have also stated in writing to the Board that the statement relating to the integrity of Woodside's financial statements is founded on a sound system of risk management and internal control that is operating effectively.

Auditor's Independence Declaration

The Auditor's Independence Declaration, as required under section 307C of the *Corporations Act 2001*, is set out on this page and forms part of this report.

Signed in accordance with a resolution of the directors.

R J Goyder, AO

Chairman

Perth, Western Australia

30 August 2022

Auditor's Independence Declaration

As lead auditor for the review of Woodside Energy Group Ltd for the half-year ended 30 June 2022, I declare that to the best of my knowledge and belief, there have been:

(a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the review, and

(b) no contraventions of any applicable code of professional conduct in relation to the review.

This declaration is in respect of Woodside Energy Group Ltd and the entities it controlled during the period.

Justin Carroll
Partner
PricewaterhouseCoopers

Perth
30 August 2022

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HALF-YEAR FINANCIAL STATEMENTS

for the half-year ended 30 June 2022

HALF-YEAR 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 18 January 2022, the Group completed the sell-down of a 49% participating interest in the Pluto Train 2 Joint Venture to Global Infrastructure Partners (GIP). As a result, the Group recognised a pre-tax gain of $427 million on the transaction (refer to Note B.5).
- The Pluto-KGP Interconnector achieved ready for start-up and commenced flowing gas from the offshore Pluto fields to Karratha Gas Plant (KGP) for processing in March 2022.
- On 1 June 2022, the Group acquired 100% of the issued share capital of BHP Petroleum International Pty Ltd (BHPP) (subsequently renamed Woodside Energy Global Holdings Pty Ltd), which held BHP Group's oil and gas business (refer to Note B.4).
- An increase in the risk free rates and current period payments offset by an increase in cost estimates has decreased restoration liabilities by $393 million (refer to Note D.2). The majority of this was recognised as a corresponding decrease in oil and gas properties.
- 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.3).

CONDENSED CONSOLIDATED INCOME STATEMENT

for the half-year ended 30 June 2022

	Notes	2022 US$m	2021 US$m
Operating revenue	A.1	**5,810**	2,504
Cost of sales	A.1	**(2,238)**	(1,535)
Gross profit		**3,572**	969
Other income	A.1	**503**	29
Other expenses	A.1	**(1,093)**	(377)
Profit before tax and net finance costs		**2,982**	621
Finance income		**31**	12
Finance costs	A.2	**(86)**	(130)
Profit before tax		**2,927**	503
Petroleum resource rent tax (PRRT) (expense)/benefit		**(424)**	60
Income tax expense		**(824)**	(221)
Profit after tax		**1,679**	342
Profit attributable to:			
Equity holders of the parent		**1,640**	317
Non-controlling interest		**39**	25
Profit for the period		**1,679**	342
Basic earnings per share attributable to equity holders of the parent (US cents)	A.4	**145.5**	33.3
Diluted earnings per share attributable to equity holders of the parent (US cents)	A.4	**144.0**	33.0

The accompanying notes form part of the half-year financial statements.

CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

for the half-year ended 30 June 2022

	2022 US$m	2021 US$m
Profit for the period	**1,679**	342
Other comprehensive income		
Items that may be reclassified to the income statement in subsequent periods:		
(Losses)/gains on cash flow hedges	**(1,582)**	17
Losses on cash flow hedges reclassified to the income statement	**255**	50
Tax recognised within other comprehensive income	**270**	(20)
Exchange fluctuations on translation of foreign operations taken to equity	**2**	-
Items that will not be reclassified to the income statement in subsequent periods:		
Remeasurement gains on defined benefit plan	**-**	12
Net gain on financial instruments at fair value through other comprehensive income	**4**	-
Other comprehensive (loss)/income for the period, net of tax	**(1,051)**	59
Total comprehensive income for the period	**628**	401
Total comprehensive income attributable to:		
Equity holders of the parent	**589**	376
Non-controlling interest	**39**	25
Total comprehensive income for the period	**628**	401

The accompanying notes form part of the half-year financial statements.

CONDENSED CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at 30 June 2022

	Notes	30 June 2022 US$m	31 December 2021 US$m
Current assets			
Cash and cash equivalents		**4,615**	3,025
Receivables		**1,779**	368
Inventories		**550**	202
Other financial assets	D.3	**493**	320
Non-current assets held for sale		**2**	254
Tax receivable		**78**	-
Other assets		**65**	109
Total current assets		**7,582**	4,278
Non-current assets			
Receivables		**910**	686
Inventories		**20**	19
Other financial assets	D.3	**92**	107
Exploration and evaluation assets	B.1	**1,192**	614
Oil and gas properties	B.2	**38,666**	18,649
Deferred tax assets		**899**	1,007
Lease assets		**1,282**	1,080
Investments accounted for using the equity method		**238**	2
Goodwill	B.4	**3,975**	-
Other assets		**96**	32
Total non-current assets		**47,370**	22,196
Total assets		**54,952**	26,474
Current liabilities			
Payables		**1,993**	639
Interest-bearing liabilities		**277**	277
Other financial liabilities	D.3	**1,302**	411
Provisions	D.2	**1,021**	605
Tax payable		**926**	413
Lease liabilities		**273**	191
Other liabilities		**159**	86
Total current liabilities		**5,951**	2,622
Non-current liabilities			
Interest-bearing liabilities		**5,103**	5,153
Deferred tax liabilities		**1,765**	878
Other financial liabilities	D.3	**423**	161
Provisions	D.2	**5,956**	2,219
Tax payable		**33**	-
Lease liabilities		**1,345**	1,176
Other liabilities		**952**	36
Total non-current liabilities		**15,577**	9,623
Total liabilities		**21,528**	12,245
Net assets		**33,424**	14,229
Equity			
Issued and fully paid shares	C.1	**29,001**	9,409
Shares reserved for employee share plans	C.1	**(42)**	(30)
Other reserves		**1,697**	683
Retained earnings		**1,978**	3,381
Equity attributable to equity holders of the parent		**32,634**	13,443
Non-controlling interest		**790**	786
Total equity		**33,424**	14,229

The accompanying notes form part of the half-year financial statements.

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

for the half-year ended 30 June 2022

	Notes	2022 US$m	2021 US$m
Cash flows from operating activities			
Profit after tax for the period		**1,679**	342
Adjustments for:			
Non-cash items			
Depreciation and amortisation		**927**	821
Depreciation of lease assets		**62**	54
Change in fair value of derivative financial instruments		**326**	80
Net finance costs		**55**	118
Tax expense		**1,248**	161
Exploration and evaluation written off		**1**	56
Restoration		**38**	14
Gain on disposal of oil and gas properties		**(430)**	-
Onerous contracts provision		**(245)**	(4)
Other		**18**	18
Changes in assets and liabilities			
Increase in trade and other receivables		**(186)**	(44)
Increase in inventories		**(39)**	(31)
Increase in lease assets		**-**	(2)
Decrease in provisions		**(43)**	(86)
Decrease in lease liabilities		**(24)**	(8)
(Increase)/decrease in other assets and liabilities		**(810)**	52
Increase in trade and other payables		**314**	6
Cash generated from operations		**2,891**	1,547
Interest received		**17**	7
Dividends received		**14**	4
Borrowing costs relating to operating activities		**(7)**	(58)
Income tax paid		**(322)**	(146)
Payments for restoration		**(70)**	(21)
Net cash from operating activities		**2,523**	1,333
Cash flows from/(used in) investing activities			
Cash received on acquisition of BHPP, including cash acquired	B.4	**1,082**	-
Payments for capital and exploration expenditure		**(998)**	(831)
Borrowing costs relating to investing activities		**(103)**	(50)
Advances to other external entities		**(48)**	(126)
Proceeds from disposal of non-current assets		**112**	-
Net cash from/(used in) investing activities		**45**	(1,007)
Cash flows used in financing activities			
Repayment of borrowings	C.2	**(42)**	(742)
Borrowing costs relating to financing activities		**(6)**	(6)
Repayment of the principal portion of lease liabilities		**(91)**	(45)
Borrowing costs relating to lease liabilities		**(50)**	(46)
Purchases of shares and payments relating to employee share plans		**(17)**	(15)
Contributions to non-controlling interests		**(45)**	(48)
Dividends paid (net of DRP)		**(717)**	(88)
Net cash used in financing activities		**(968)**	(990)
Net increase/(decrease) in cash held		**1,600**	(664)
Cash and cash equivalents at the beginning of the period		**3,025**	3,604
Effects of exchange rate changes		**(10)**	(2)
Cash and cash equivalents at the end of the period		**4,615**	2,938

The accompanying notes form part of the half-year financial statements.

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the half-year ended 30 June 2022

	Issued and fully paid shares	Shares reserved for employee share plans	Employee benefits reserve	Foreign currency translation reserve	Hedging reserve	Distributable profits reserve	Other reserve	Retained earnings	Equity holders of the parent	Non-controlling interest	Total equity
Notes	C.1	C.1									
	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m
At 1 January 2022	**9,409**	**(30)**	**232**	**793**	**(400)**	**58**	**-**	**3,381**	**13,443**	**786**	**14,229**
Transfers	-	-	-	-	-	**2,025**	-	**(2,025)**	-	-	-
Profit for the period	-	-	-	-	-	-	-	**1,640**	**1,640**	**39**	**1,679**
Other comprehensive income/(loss)	-	-	-	**2**	**(1,057)**	-	**4**	-	**(1,051)**	-	**(1,051)**
Total comprehensive income/(loss) for the period	-	-	-	**2**	**(1,057)**	-	**4**	**1,640**	**589**	**39**	**628**
Dividend Reinvestment Plan	**332**	-	-	-	-	-	-	-	**332**	-	**332**
Shares issued for acquisition of BHPP	**19,265**	-	-	-	-	-	-	-	**19,265**	-	**19,265**
Replacement employee share plan issued on acquisition of BHPP	-	-	**18**	-	-	-	-	-	**18**	-	**18**
Employee share plan purchases	-	**(17)**	-	-	-	-	-	-	**(17)**	-	**(17)**
Employee share plan redemptions	-	**5**	**(5)**	-	-	-	-	-	-	-	-
Share-based payments (net of tax)	-	-	**27**	-	-	-	-	-	**27**	-	**27**
Dividends paid	-	-	-	-	-	-	-	**(1,018)**	**(1,018)**	**(35)**	**(1,053)**
Transaction costs associated with the issue of shares	**(5)**	-	-	-	-	-	-	-	**(5)**	-	**(5)**
At 30 June 2022	**29,001**	**(42)**	**272**	**795**	**(1,457)**	**2,083**	**4**	**1,978**	**32,634**	**790**	**33,424**
At 1 January 2021	9,297	(23)	219	793	(71)	462	-	1,398	12,075	800	12,875
Profit for the period	-	-	-	-	-	-	-	317	317	25	342
Other comprehensive income	-	-	12	-	47	-	-	-	59	-	59
Total comprehensive income for the period	-	-	12	-	47	-	-	317	376	25	401
Dividend Reinvestment Plan	26	-	-	-	-	-	-	-	26	-	26
Employee share plan purchases	-	(15)	-	-	-	-	-	-	(15)	-	(15)
Employee share plan redemptions	-	6	(6)	-	-	-	-	-	-	-	-
Share-based payments (net of tax)	-	-	20	-	-	-	-	-	20	-	20
Dividends paid	-	-	-	-	-	(115)	-	-	(115)	(31)	(146)
At 30 June 2021	9,323	(32)	245	793	(24)	347	-	1,715	12,367	794	13,161

The accompanying notes form part of the half-year financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 30 June 2022

About these statements

Following the approval by shareholders at the Annual General Meeting on 19 May 2022, Woodside Petroleum Ltd has registered the change of company name to Woodside Energy Group Ltd (Woodside or the Group). Woodside is a for-profit entity limited by shares, incorporated and domiciled in Australia. Its shares are publicly traded on the Australian Securities Exchange (ASX), on the Main Market for listed securities of the London Stock Exchange (LSE) (with trades settled in the form of UK Depository Interests) and on the New York Stock Exchange (NYSE) (in the form of Woodside American Depositary Shares). The nature of the operations and principal activities of the Group are described in the Operational Overview, Projects and Development Activities sections and in the segment information below.

The condensed consolidated half-year financial statements were authorised for issue in accordance with a resolution of the Directors on 30 August 2022.

Statement of compliance

The condensed consolidated half-year financial statements are condensed general purpose financial statements, which have been prepared in accordance with Australian Accounting Standard (AASB) 134 *Interim Financial Reporting* as issued by the Australian Accounting Standards Board and the Australian *Corporations Act 2001*. Compliance with AASB 134 *Interim Financial Reporting* ensures compliance with International Accounting Standard (IAS) 34 *Interim Financial Reporting* as issued by the International Accounting Standards Board.

The condensed consolidated half-year financial statements do not include all notes of the type normally included in annual financial statements. Accordingly, these condensed consolidated half-year financial statements are to be read in conjunction with the Financial Statements within the Annual Report for the year ended 31 December 2021 (2021 Financial Statements) and any public announcements made by Woodside during the period ended 30 June 2022 in accordance with the continuous disclosure requirements of the Australian *Corporations Act 2001* and the relevant ASX, LSE and NYSE Listing Rules.

Subsequent to the merger with BHP Petroleum International Pty Ltd (subsequently renamed Woodside Energy Global Holdings Pty Ltd), BHPP's accounting policies have been aligned with the Group. The Group's accounting policies are consistent with those disclosed in the Group's 2021 Financial Statements. Adoption of new or amended standards and interpretations effective 1 January 2022 did not result in any significant changes to the Group's accounting policies.

The significant accounting estimates and judgements are consistent with those disclosed in the 2021 Financial Statements. Estimates have been revised, where required, to reflect current market conditions including the impact of COVID-19 and climate change. Updated estimates used for impairment assessments and the measurement of onerous contracts are disclosed in Notes B.3 and D.2 respectively. Given ongoing economic uncertainty, these assumptions could change in the future. New estimates and judgements for significant transactions during the period including the recognition of goodwill as a result of the business combination and the sell-down of Train 2 are disclosed in Notes B.4 and B.5 respectively.

Currency

The functional and presentation currency of Woodside and all its material subsidiaries is US 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 of amounts

The amounts contained in the condensed consolidated half-year 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 condensed consolidated half-year 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 condensed consolidated half-year financial statements.

Basis of preparation (continued)

The condensed consolidated half-year financial statements comprise the financial results of the Group and its subsidiaries for the period ended 30 June 2022. 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 apply the same reporting period and accounting policies as the parent company in preparation of the condensed consolidated half-year financial statements. 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, 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.

Comparative information

The condensed consolidated half-year 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 condensed consolidated half-year financial statements of the current period.

Reporting segments

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 determining the allocation of resources.

As a result of the merger with BHPP on 1 June 2022, the Group has transformed into a global energy company which has led to a change in how financial information is reported in the Group. The disclosed operating segments have been updated to reflect this change and 2021 amounts have been restated to be presented on the same basis.

Operating segments outlined below are identified by management based on the nature and geographical location of the business and venture.

Australia – Exploration, evaluation, development, production and sale of liquified natural gas, pipeline gas, crude oil and condensate and natural gas liquids in Australia.

International – Exploration, evaluation, development, production and sale of pipeline gas, crude oil and condensate and natural gas liquids in international jurisdictions outside of Australia.

Marketing – Trading of liquified natural gas (non-produced) and optimisation activities generating incremental value from produced liquified natural gas via scheduling, shipping and/or contract management. The incremental income and expenses from marketing activities relating to hydrocarbons other than liquified natural gas (e.g. liquids, pipeline gas) are not included in the segment for the half-year ended 30 June 2022.

Corporate/Other items – Corporate/Other 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.

In addition to the updated segments, the Group has reassessed the reporting of revenue from the sale of liquified natural gas on a portfolio basis. With the Marketing segment separately reported for the half-year ended 30 June 2022, the Group will no longer report revenue from the sale of liquified natural gas on a portfolio basis to better represent the revenues and margins generated by each segment. 2021 amounts have been restated to be presented on the same basis.

A. Earnings for the period

A.1 Segment revenue and expenses

	Australia		International		Marketing		Corporate/ Other		Consolidated	
	2022 US$m	2021[7] US$m	2022 US$m	2021[7] US$m	2022 US$m	2021[7] US$m	2022 US$m	2021[7] US$m	2022 US$m	2021 US$m
Liquified natural gas	3,119	1,470	-	-	986	338	-	-	4,105	1,808
Pipeline gas	232	22	57	-	-	-	-	-	289	22
Crude oil and condensate	1,066	566	243	-	-	-	-	-	1,309	566
Natural gas liquids	11	21	5	-	-	-	-	-	16	21
Revenue from sale of hydrocarbons	4,428	2,079	305	-	986	338	-	-	5,719	2,417
Intersegment revenue[1]	(323)	(102)	-	-	323	102	-	-	-	-
Processing and services revenue	77	70	-	-	-	-	-	-	77	70
Shipping and other revenue	6	4	-	-	8	13	-	-	14	17
Other revenue	(240)	(28)	-	-	331	115	-	-	91	87
Operating revenue[2]	4,188	2,051	305	-	1,317	453	-	-	5,810	2,504
Production costs	(350)	(229)	(33)	-	-	-	(14)	4	(397)	(225)
Royalties, excise and levies	(189)	(75)	(14)	-	-	-	(17)	-	(220)	(75)
Insurance	(18)	(13)	(1)	-	-	-	(3)	(3)	(22)	(16)
Inventory movement	15	1	-	-	-	-	-	-	15	1
Costs of production	(542)	(316)	(48)	-	-	-	(34)	1	(624)	(315)
Land and buildings	(25)	(26)	-	-	-	-	-	-	(25)	(26)
Transferred exploration and evaluation	(50)	(40)	(1)	-	-	-	-	-	(51)	(40)
Plant and equipment	(774)	(738)	(58)	-	-	-	(16)	(15)	(848)	(753)
Oil and gas properties depreciation and amortisation	(849)	(804)	(59)	-	-	-	(16)	(15)	(924)	(819)
Shipping and direct sales costs	(92)	(78)	(4)	-	(15)	(15)	17	26	(94)	(67)
Trading costs	-	-	-	-	(790)	(355)	-	-	(790)	(355)
Other hydrocarbon costs	(19)	-	-	-	-	-	-	-	(19)	-
Other cost of sales	(3)	-	-	-	-	-	-	-	(3)	-
Movement in onerous contract provision[3]	-	-	-	-	216	21	-	-	216	21
Other cost of sales	(114)	(78)	(4)	-	(589)	(349)	17	26	(690)	(401)
Cost of sales	(1,505)	(1,198)	(111)	-	(589)	(349)	(33)	12	(2,238)	(1,535)
Gross profit	2,683	853	194	-	728	104	(33)	12	3,572	969
Other income[4]	494	11	4	(2)	5	-	-	20	503	29
Exploration and evaluation expenditure	(7)	(8)	(19)	(18)	-	-	(14)	(6)	(40)	(32)
Amortisation	-	-	(3)	(2)	-	-	-	-	(3)	(2)
Write-offs	-	-	(1)	(56)	-	-	-	-	(1)	(56)
Exploration and evaluation	(7)	(8)	(23)	(76)	-	-	(14)	(6)	(44)	(90)
General, administration and other costs[5]	(5)	(1)	(12)	3	-	-	(525)	(70)	(542)	(68)
Depreciation of lease assets	(21)	(14)	(1)	-	-	-	(40)	(40)	(62)	(54)
Restoration movement	(31)	(22)	(10)	8	-	-	3	-	(38)	(14)
Other[6]	(18)	(10)	(64)	(42)	(227)	(31)	(98)	(68)	(407)	(151)
Other costs	(75)	(47)	(87)	(31)	(227)	(31)	(660)	(178)	(1,049)	(287)
Other expenses	(82)	(55)	(110)	(107)	(227)	(31)	(674)	(184)	(1,093)	(377)
Profit/(loss) before tax and finance costs	3,095	809	88	(109)	506	73	(707)	(152)	2,982	621

1. Intersegment revenue comprises the incremental income net of all associated expenses generated by the Marketing activities optimising the liquified natural gas portfolio. The value is incremental income net of incremental costs.
2. Operating revenue includes revenue from contracts with customers of $5,802 million (2021: $2,488 million) and sub-lease income of $8 million (2021: $16 million) disclosed within shipping and other revenue.
3. Comprises changes in estimates of $245 million offset by provisions used of $29 million (2021: Comprised provisions used of $17 million, revision of discount rates of $8 million offset by changes in estimates of $4 million). Refer to Note D.2 for more details.
4. Includes gain on Train 2 sell-down, fees and recoveries, foreign exchange gains and other income not associated with the ongoing operations of the business.
5. Transaction costs incurred as a result of the BHPP merger on 1 June 2022 are included in the Corporate/Other segment. Refer to Note B.4.
6. Includes losses on hedging activities and other expenses not associated with the ongoing operations of the business.
7. The 2021 amounts have been restated to reflect the changes in operating segments and portfolio reporting for LNG revenue.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 30 June 2022

A.2 Finance costs

	2022 US$m	2021 US$m
Interest on interest-bearing liabilities	101	104
Interest on lease liabilities	58	46
Accretion charge	26	13
Other finance costs	14	15
Less: Finance costs capitalised against qualifying assets	(113)	(48)
	86	130

A.3 Dividends paid and proposed

Woodside Energy Group Ltd, the parent entity, paid and proposed dividends as set out below:

	2022 US$m	2021 US$m
(a) Dividends paid during the financial period Prior year fully franked final dividend US$1.05, paid on 23 March 2022 (2021: US$0.12, paid on 24 March 2021)	1,018	115
(b) Dividend declared subsequent to the reporting period **(not recorded as a liability)** Current year fully franked interim dividend US$1.09 to be paid on 6 October 2022 (2021: US$0.30, paid on 24 September 2021)	2,070	289

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 will remain in place until further notice.

A.4 Earnings per share

	2022	2021
Profit attributable to equity holders of the parent (US$m)	1,640	317
Weighted average number of shares on issue for basic earnings per share	1,127,109,476	951,489,253
Effect of dilution from contingently issuable shares	11,895,577	9,069,843
Weighted average number of shares on issue adjusted for the effect of dilution	1,139,005,053	960,559,096
Basic earnings per share (US cents)	145.5	33.3
Diluted earnings per share (US cents)	144.0	33.0

Earnings per share is calculated by dividing the profit for the period attributable to ordinary equity holders of the parent by the weighted average number of shares on issue during the period. 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. As at 30 June 2022, 11,895,577 (2021: 9,069,843) awards granted under the Woodside employee share plans are considered dilutive.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 30 June 2022

B. Production and growth assets

B.1 Exploration and evaluation

	Asia Pacific US$m	Americas US$m	Africa US$m	Other US$m	Total US$m
Half-year ended 30 June 2022					
Carrying amount at 1 January 2022	**546**	-	**68**	-	**614**
Acquisitions through business combination[1]	**112**	**465**	-	-	**577**
Additions	**6**	-	-	**1**	**7**
Amortisation of licence acquisition costs	-	**(2)**	**(1)**	-	**(3)**
Expensed[2]	-	-	-	**(1)**	**(1)**
Transferred exploration and evaluation	-	-	**(2)**	-	**(2)**
Carrying amount at 30 June 2022	**664**	**463**	**65**	-	**1,192**
Year ended 31 December 2021					
Carrying amount at 1 January 2021	1,981	-	64	-	2,045
Additions	494	-	7	-	501
Amortisation of licence acquisition costs	-	-	(3)	-	(3)
Expensed[2]	(265)	-	-	-	(265)
Transferred exploration and evaluation	(1,664)	-	-	-	(1,664)
Carrying amount at 31 December 2021	546	-	68	-	614

1. Acquisitions through business combination have been recognised on a provisional basis. Adjustments will be made to the provisional amounts if new information is obtained within 12 months from the acquisition date. Refer to Note B.4 for details.
2. $1 million (31 December 2021: $56 million) relates to costs of unsuccessful wells. For the year ended 31 December 2021, $209 million relates to capitalised costs written off due to the Group's decision to withdraw its interests in Myanmar.

B.2 Oil and gas properties

	Land and buildings US$m	Transferred exploration and evaluation US$m	Plant and equipment US$m	Projects in development US$m	Total US$m
Half-year ended 30 June 2022					
Carrying amount at 1 January 2022	**739**	**526**	**12,465**	**4,919**	**18,649**
Acquisitions through business combination[1]	**63**	**-**	**13,869**	**5,778**	**19,710**
Additions[2]	**-**	**-**	**(404)**	**1,676**	**1,272**
Disposals at written down value	**(3)**	**(10)**	**(28)**	**-**	**(41)**
Depreciation and amortisation	**(25)**	**(50)**	**(849)**	**-**	**(924)**
Completions and transfers	**1**	**2**	**542**	**(545)**	**-**
Carrying amount at 30 June 2022	**775**	**468**	**25,595**	**11,828**	**38,666**
At 30 June 2022					
Historical cost	**1,759**	**1,497**	**46,807**	**12,227**	**62,290**
Accumulated depreciation and impairment	**(984)**	**(1,029)**	**(21,212)**	**(399)**	**(23,624)**
Net carrying amount	**775**	**468**	**25,595**	**11,828**	**38,666**
Year ended 31 December 2021					
Carrying amount at 1 January 2021	749	431	12,091	2,195	15,466
Additions	-	-	13	2,321	2,334
Disposals at written down value	(2)	-	(5)	(22)	(29)
Depreciation and amortisation	(51)	(79)	(1,450)	-	(1,580)
Impairment losses	(10)	-	-	-	(10)
Impairment reversals	44	66	911	37	1,058
Completions and transfers	11	108	905	640	1,664
Transfer to non-current assets held for sale	(2)	-	-	(252)	(254)
Carrying amount at 31 December 2021	739	526	12,465	4,919	18,649
At 31 December 2021					
Historical cost	1,701	1,495	32,797	5,321	41,314
Accumulated depreciation and impairment	(962)	(969)	(20,332)	(402)	(22,665)
Net carrying amount	739	526	12,465	4,919	18,649

1. Acquisitions through business combination have been recognised on a provisional basis. Adjustments will be made to the provisional amounts if new information is obtained within 12 months from the acquisition date. Refer to Note B.4 for details.
2. Includes $1,509 million of capital additions and $113 million of capitalised borrowing costs offset by $350 million following changes in restoration provision assumptions.

The Group has capital expenditure commitments contracted for, but not provided for in the financial statements, of $7,899 million (31 December 2021: $7,875 million).

B.3 Impairment of non-current assets

For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units (CGUs) that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units. Goodwill that is created on acquisition as a consequence of deferred tax balances is tested for impairment net of those associated deferred tax balances. Goodwill is tested at least annually for impairment and more frequently if events or changes in circumstances indicate that it might be impaired.

The Group assessed each CGU for indicators of impairment and impairment reversal. No indicators of impairment or impairment reversal were identified in the period ended 30 June 2022. Revised Brent oil price estimates are disclosed in Note D.2. Other key estimates and judgements used have not materially changed from those disclosed in Note B.4 in the 2021 Financial Statements.

B.4 Business combination

BHP Petroleum merger

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 Share Sale Agreement (SSA) and the integration and transition services agreement were executed on 22 November 2021. Under the SSA, the merger took economic effect from 1 July 2021 and Woodside became entitled to the economic benefits and risks of the assets and liabilities that were the subject of the merger from that date.

On 19 May 2022, 98.66% of Woodside shareholders voted in favour of the merger at Woodside's Annual General Meeting.

On 1 June 2022, the transaction was completed with the Group acquiring 100% of the issued share capital of BHP Petroleum International Pty Ltd (subsequently renamed Woodside Energy Global Holdings Pty Ltd), which held BHP's oil and gas business. In exchange, the Group issued 914,768,948 new Woodside shares to BHP as part of the merger consideration. The transaction has been accounted for as a business combination with an acquisition date of 1 June 2022. The Group's net profit after tax for the period ended 30 June 2022 will incorporate BHPP results from acquisition date. The merger is expected to create opportunities to realise ongoing synergies.

Due to the size, complexity and timing of the transaction, the related acquisition accounting is not yet finalised and accordingly the assets acquired and liabilities assumed are measured on a provisional basis. If new information is obtained within 12 months from the acquisition date about facts and circumstances that existed at the acquisition date, adjustments will be made to the provisional amounts recognised including the value of goodwill.

The merged Group's financial results could be adversely affected by impairments of goodwill or other intangible assets, the application of future accounting policies or interpretations of existing accounting policies including by regulatory direction, and changes in estimates of decommissioning costs. Details and risks have been included in the Merger Explanatory Memorandum released on 8 April 2022.

Given the purchase consideration was agreed on 22 November 2021 based on a fixed number of shares, the final value of consideration paid was subject to fluctuations in share price until completion on 1 June 2022. This has resulted in a material goodwill number which will be subject to impairment in future, for example should commodity prices decrease.

Details of the purchase consideration and the provisional fair value of goodwill, identifiable assets and liabilities of BHPP acquired are as follows:

Provisional fair value of net identifiable assets and goodwill arising on acquisition date	US$m
Cash and cash equivalents	399
Receivables	1,170
Inventories	295
Investments accounted for using the equity method	240
Other financial assets	59
Other assets	19
Exploration and evaluation assets	577
Oil and gas properties	19,710
Lease assets	142
Payables	(925)
Lease liabilities	(268)
Other liabilities	(1,071)
Provisions	(4,806)
Tax payable	(366)
Deferred tax liabilities	(550)
Net identifiable assets acquired	**14,625**
Goodwill arising on acquisition	3,975
Purchase consideration	**18,600**

Purchase consideration	US$m
Shares issued, at fair value	19,265
Other reserves (Share replacement awards)	18
Provisional locked box payment received[1]	(683)
Total purchase consideration	**18,600**

1. Represents the positive net cash flow of $1,513 million generated by BHPP assets from the effective date of the business combination offset by the notional dividend distribution of $830 million paid to BHP.

B.4 Business combination (continued)

Analysis of cash flows on acquisition	**US$m**
Cash acquired on acquisition	399
Provisional locked box payment received	683
Net cash flow received on acquisition (included in the Statement of Cash Flows as Investing activities)	**1,082**

Acquisition-related costs of $424 million that were not directly attributable to the issue of shares are included as an expense in General, Administration and Other Costs in the Income Statement. $258 million have been paid and included in the Statement of Cash Flows as Operating activities. Acquisition-related costs of $5 million directly attributable to the issue of shares are included in Contributed Equity.

Shares issued, at fair value

The fair value of 914,768,948 shares issued as part of the consideration paid to BHP was $19,265 million. This was based on the published share price on 1 June 2022 of US$21.06 per share.

Provisional locked box payment received

The Group received $683 million as part of the merger consideration which includes the locked box payment of $1,513 million representing the positive net cash flow generated by BHPP assets from the effective date of the transaction to completion date offset by the notional dividend distribution of $830 million paid to BHP.

Revenue and contribution to the Group

The acquired business contributed operating revenue of $650 million and profit before tax of $341 million to the Group from the acquisition date to 30 June 2022. If the acquisition had occurred on 1 January 2022, consolidated operating revenue and profit before tax would have been higher by $3,115 million and $1,265 million respectively.

Acquired receivables

The fair value of receivables approximates the gross amount of trade receivables. None of the receivables have been impaired and the full contractual amounts are expected to be collected.

Other liabilities

The Group recognised contingent liabilities of $39 million within Other Liabilities. This is based on the Group's assessment of the fair value of contingent liabilities acquired on acquisition, taking into account a range of possible outcomes. The contingent liabilities include $27 million as a result of previous audits of production sharing agreements.

As at 30 June 2022, there have been no changes to the amount recognised on acquisition date.

Goodwill

Goodwill arising from the acquisition has been recognised as the excess of consideration paid above the fair value of the assets acquired and liabilities assumed as part of the business combination. A portion of the goodwill arises from the net deferred tax liability recognised on acquisition as a consequence of asset tax bases received in the merger being lower than the fair value of the assets acquired. Given the timing of the acquisition, it has been impracticable to complete the allocation of the remaining goodwill to the Group's CGUs. As such, the Group cannot make disclosures and information on goodwill allocation that will be provided as part of the 31 December 2022 financial statements. The goodwill is not deductible for tax purposes.

Goodwill is initially measured at cost and is subsequently measured at cost less any accumulated impairment losses. For the purposes of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's CGUs or groups of CGUs no larger than an operating segment that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill has been allocated to a CGU and part of the operation within that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal. Goodwill is not amortised but will be assessed at least annually for impairment and more frequently if events or changes in circumstances indicate that it might be impaired.

B.4 Business combination (continued)

Share replacement awards

In accordance with the terms of the SSA, the Group exchanged equity-settled share-based payment awards held by employees of BHPP for equity-settled share-based payment awards of Woodside. The replacement awards are based on service conditions with a vesting date of 31 August 2023 and 31 August 2024. The fair value of the replacement awards on acquisition is $49 million based on a forfeiture rate of 3%. $18 million has been included as part of the purchase consideration and the remaining amount will be recognised as post-acquisition compensation cost.

Business combination accounting

The acquisition method of accounting is used to account for all business combinations, including business combinations involving entities or businesses under common control, regardless of whether equity instruments are issued or liabilities incurred or assumed at the date of exchange. Where equity instruments are issued in an acquisition, the fair value of the instruments is their published market price as at the date of exchange.

Transaction costs arising on the issue of equity instruments are recognised directly in equity. Transaction costs that were not directly attributable to the issue of shares are expensed as incurred.

Contractual assets and liabilities in respect of sales agreements are recognised at fair value.

Restoration provisions are recognised on acquisition at fair value.

B.5 Disposal of assets

Sell-down of Train 2

On 15 November 2021 the Group entered into a sale and purchase agreement with Global Infrastructure Partners (GIP) for the sale of a 49% non-operating 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%. The Group recognised a pre-tax gain on sale of $427 million.

The arrangements require GIP to fund its 49% share of capital expenditure from 1 October 2021 and an additional amount of construction capital expenditure of $822 million on behalf of the Group. If the total capital expenditure incurred is less than $5,800 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 $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. As at 30 June 2022, the fair value of the remaining unpaid funding has been recognised as a current receivable and will be recognised as Oil and Gas Properties in the future as paid by GIP.

Key estimates and judgements

Sell-down of Train 2

Given the arrangements include provisions for GIP to sell its 49% interest back to Woodside if the status of key regulatory environmental approvals materially changes and the requirement for Woodside to fund up to $822 million of GIP's share in the event of a cost overrun, judgement is required to determine if the sell-down of Train 2 constitutes a sale and if a portion of the transaction price should be considered a variable consideration.

Judgement was used to determine that the sell-down of Train 2 constituted a sale given the various conditions included in the sale and purchase agreement. The Group determined that a sale occurred as control of the 49% interest was passed to GIP on completion date. Control is determined as the ability to direct the use of, and obtain substantially all of the economic benefits of, the associated interest.

Judgement was used to determine if it is highly probable that a significant reversal will not occur in relation to the consideration received. For the half-year ended 30 June 2022, the Group estimated the variable consideration based on the construction capital expenditure cost profile, the development schedule, and assessing the probability and impact of any event which may result in a significant reversal. The constraining estimates of variable consideration have been applied resulting in the pre-tax gain on sale of $427 million. The variable consideration will be remeasured at each reporting period with any changes recognised through the Income Statement. The variable consideration has been remeasured as at 30 June 2022 with no revaluation gain or loss recognised.

C. Debt and capital

C.1 Contributed equity

Issued and fully paid shares	Number of shares	US$m
Half-year ended 30 June 2022		
Opening balance	**969,631,826**	**9,409**
DRP – ordinary shares issued at US$23.14 (2021 final dividend)	**14,348,997**	**332**
Ordinary shares issued at US$21.06 for the acquisition of BHPP[1]	**914,768,948**	**19,265**
Transaction costs associated with the issue of shares	**-**	**(5)**
Amounts as at 30 June 2022	**1,898,749,771**	**29,001**
Year ended 31 December 2021		
Opening balance	962,225,814	9,297
DRP – ordinary shares issued at US$19.03 (2020 final dividend)	1,354,072	26
DRP – ordinary shares issued at US$14.21 (2021 interim dividend)	6,051,940	86
Amounts as at 31 December 2021	969,631,826	9,409

1. 914,768,948 new Woodside shares were issued as consideration for the BHPP merger. Refer to Note B.4 for details.

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 respect of its issued shares.

Shares reserved for employee share plans	30 June 2022 US$m	31 December 2021 US$m
2,289,826 (2021: 1,819,744) reserved shares	**(42)**	(30)

C.2 Interest-bearing liabilities and financing facilities

During the period, the Group repaid $42 million of the Japan Bank for International Cooperation (JBIC) facility. There were no other material changes to interest-bearing liabilities and financing facilities. For the year ended 31 December 2021, the Group redeemed the $700 million 2021 US bond and repaid $84 million on the JBIC facility.

Subsequent to period end, the Group repaid a number of its financing facilities. In addition, the Group also refinanced and increased an existing committed undrawn syndicated facility (refer to Note E.4).

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 $4,083 million (31 December 2021: $4,081 million) and a fair value of $3,920 million (31 December 2021: $4,443 million). The medium-term notes have a carrying amount of $583 million (31 December 2021: $592 million) and a fair value of $567 million (31 December 2021: $604 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.

D. Other assets and liabilities

D.1 Segment assets and liabilities

	30 June 2022 US$m	31 December 2021[2] US$m
(a) Segment assets[1]		
Australia	**28,483**	18,163
International	**17,483**	2,877
Marketing	**182**	217
Corporate/Other	**8,804**	5,217
	54,952	26,474

	30 June 2022 US$m	31 December 2021[2] US$m
(b) Segment liabilities[1]		
Australia	**6,696**	2,889
International	**2,926**	435
Marketing	**731**	639
Corporate/Other	**11,175**	8,282
	21,528	12,245

1. Acquisitions through business combination have been recognised on a provisional basis. Adjustments will be made to the provisional amounts if new information is obtained within 12 months from the acquisition date. Refer to Note B.4 for details.
2. The 2021 amounts have been restated to reflect the changes in operating segments. Refer to 'Reporting Segments' for details.

Refer to 'About these statements' for information relating to the Group's segments. Corporate/other assets mainly comprise cash and cash equivalents, lease assets and deferred tax assets. Corporate/other liabilities mainly comprise interest-bearing liabilities, lease liabilities and deferred tax liabilities.

D.2 Provisions

	Restoration[1] US$m	Employee benefits US$m	Onerous contracts[2] US$m	Other US$m	Total US$m
Half-year ended 30 June 2022					
At 1 January 2022	**2,218**	**286**	**214**	**106**	**2,824**
Acquisitions through business combination[3]	**4,312**	**329**	**-**	**165**	**4,806**
Change in provision	**(393)**	**(162)**	**(216)**	**62**	**(709)**
Unwinding of present value discount	**24**	**30**	**2**	**-**	**56**
Carrying amount at 30 June 2022	**6,161**	**483**	**-**	**333**	**6,977**
Current	**482**	**252**	**-**	**287**	**1,021**
Non-current	**5,679**	**231**	**-**	**46**	**5,956**
Net carrying amount	**6,161**	**483**	**-**	**333**	**6,977**
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

1. 2022 change in provision is due to a revision of discount rates of $492 million (primarily due to an increase in risk free rates) and provisions used of $68 million, offset by changes in estimates of $167 million.
2. 2022 change in provision is due to changes in estimates of $245 million offset by provisions used of $29 million.
3. Acquisitions through business combination have been recognised on a provisional basis. Adjustments will be made to the provisional amounts if new information is obtained within 12 months from the acquisition date. Refer to Note B.4 for details.

D.2 Provisions (continued)

Key estimates and judgements

Restoration obligations

The key estimates and judgements of the Group's restoration obligations have not materially changed from those disclosed in Note D.5 in the 2021 Financial Statements. Whilst the provisions reflect the Group's best estimate based on current knowledge and information, actual costs and cash outflows may 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 30 June 2022.

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.

As at 30 June 2022, the Corpus Christi contract is expected to return a positive value and on this basis the provision has been reversed to nil (31 December 2021: $214 million). Changes in assumptions predominantly relating to the narrowing of the spread between the sales price and purchase price could result in the contract becoming onerous in the future.

Assumptions used to determine the present value as at 30 June 2022 are set out below:

- Remaining contract term – 18.5 years.
- Discount rate – a pre-tax, risk free US government bond rate of 3.32% (31 December 2021: 1.855%) 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 incorporate known sales pricing information[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 30 June 2022 were:

	2022	**2023**	**2024**	**2025**	**2026**
TTF (US$/MMBtu)	26.0	19.4	13.5	7.0	7.2
Brent (US$/bbl)	100	87	78	69	70[2]
Henry Hub (US$/MMBtu)	6.0	4.6	3.6	3.2	3.3[3]

1. For committed volumes, contract pricing has been applied.
2. Long-term oil prices are based on US$65/bbl (2022 real terms) from 2025 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%.

D.3 Other financial assets and liabilities

	30 June 2022 US$m	31 December 2021 US$m
Other financial assets		
Financial instruments at fair value through profit and loss		
Derivative financial instruments designated as hedges	**158**	134
Other financial assets	**427**	293
Total other financial assets	**585**	427
Current	**493**	320
Non-current	**92**	107
Net carrying amount	**585**	427
Other financial liabilities		
Financial instruments at fair value through profit and loss		
Derivative financial instruments designated as hedges	**1,700**	563
Other financial liabilities	**25**	9
Total other financial liabilities	**1,725**	572
Current	**1,302**	411
Non-current	**423**	161
Net carrying amount	**1,725**	572

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 2022 to 2023 in order to achieve a minimum average sales price of $75 per barrel.
- The Group entered into additional 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 to mitigate pricing risk for 2022 to 2024. As a result of hedging and term sales, approximately 94% of Corpus Christi volumes in 2022, 73% in 2023 and 27% in 2024 have reduced pricing risk.
- The Group also restruck $150 million of the TTF hedges at current market prices to reduce the derivative financial liability.
- Through the use of foreign exchange forward contracts, the Group hedged its 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.

The following table presents the Group's derivative financial instruments designated as hedges, measured and recognised at fair value:

	30 June 2022 US$m	31 December 2021 US$m
Oil swaps (cash flow hedges)	**(720)**	(1)
HH Corpus Christi commodity swaps (cash flow hedges)	**85**	31
TTF Corpus Christi commodity swaps (cash flow hedges)	**(917)**	(465)
TTF commodity swaps (cash flow hedges)	**-**	4
Interest rate swaps (cash flow hedges)	**32**	(17)
Cross-currency interest rate swaps (cash flow and fair value hedges)	**1**	9
FX forwards (cash flow hedges)	**(23)**	10
Total derivative financial instruments designated as hedges	**(1,542)**	(429)

D.3 Other financial assets and liabilities (continued)

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 the three-month and six-month LIBOR will be phased out and eventually replaced by June 2023.

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 $916 million (31 December 2021: $957 million) and $377 million (31 December 2021: $367 million) respectively, which reference 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. 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.

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.

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. Other financial assets and other financial liabilities set out in this note are classified as Level 2 on the fair value hierarchy with market observable inputs. During the period, there were no reclassifications between the fair value hierarchy levels.

There were no changes to the Group's valuation processes, valuation techniques and types of inputs used in the fair value measurements during the period.

Financial risk factors

The Group's activities expose its financial instruments to a variety of market risks, including foreign exchange, commodity price and interest rate risk. The half-year financial report does not include all financial risk management information and disclosures required in the annual report and as such, should be read in conjunction with the Group's 2021 Financial Statements. There have been no significant changes in the risk management policies since 31 December 2021.

E. Other items

E.1 Contingent liabilities and assets

	30 June 2022 US$m	31 December 2021 US$m
Contingent liabilities at reporting date		
Not otherwise provided for in the financial statements:		
Contingent liabilities	**166**	195
Guarantees	**2**	7
	168	202

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 condensed half-year 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.

There were no contingent assets as at 30 June 2022 or 31 December 2021.

E.2 Related party transactions

The Group's related parties transactions are predominantly with associates of the Group. During the period, the transactions with related parties include purchases of goods/services of $2 million and dividend income of $3 million. As at 30 June 2022, the total amounts owing to related parties is $2 million.

E.3 Changes to the composition of the Group

Since the last annual reporting, PT Woodside Energy Indonesia, a wholly owned subsidiary, was incorporated in Indonesia on 27 April 2022. In addition, as a result of the merger with BHPP on 1 June 2022, the following subsidiaries, joint arrangements and associates were acquired. The list below includes entity name changes in July 2022:

Entities acquired	Location	Ownership %
Woodside Energy Global Holdings Pty Ltd	Australia	100.00
Woodside Energy Global Pty Ltd	Australia	100.00
North West Shelf Liaison Company Pty Ltd	Australia	16.67[1]
North West Shelf Shipping Service Company Pty Ltd	Australia	16.67[1]
Perdido Mexico Pipeline Holdings, S.A. de C.V.	Mexico	99.99[2]
Perdido Mexico Pipeline, S. de R.L. de C.V.	Mexico	99.99[2]
Woodside Energy Investments Pty Ltd	Australia	100.00
Woodside Energia Brasil Investimentos Ltda.	Brazil	99.97[3]
Woodside Energia Brasil Exploração e Produção Ltda.	Brazil	99.99[4]
Woodside Energy (Great Britain) Limited	United Kingdom	100.00
Woodside Energy (North West Shelf) Pty Ltd	Australia	100.00
North West Shelf Lifting Coordinator Pty Ltd	Australia	16.67[1]
North West Shelf Gas Pty Limited	Australia	16.67[1]
International Gas Transportation Company Limited	Bermuda	16.67[5]
China Administration Company Pty Ltd	Australia	16.67[1]
Woodside Energy (Trinidad) Holdings Ltd.	Saint Lucia	100.00
Woodside Energy (Trinidad-3A) Ltd	Republic of Trinidad and Tobago	100.00
Woodside Energy USA Operations Inc	United States	90.00[6]
Hamilton Brothers Petroleum Corporation	United States	100.00
Hamilton Oil Company LLC	United States	100.00
Woodside Energy Boliviana Inc.	United States	100.00
Woodside Energy (North America) LLC	United States	100.00
Woodside Energy (Americas) Inc.	United States	100.00
Woodside Energy (GOM) Inc.	United States	100.00

E.3 Changes to the composition of the Group (continued)

Entities acquired	Location	Ownership %
Woodside Energy Hawaii Inc.	United States	100.00
Iwilei District Participating Parties, LLC	United States	14.96[5]
Woodside Energy Resources Inc.	United States	100.00
Woodside Energy Holdings (Resources) Inc.	United States	100.00
Woodside Energy USA Services Inc.	United States	100.00
Woodside Energy Marketing Inc.	United States	100.00
Woodside Energy (Deepwater) Inc.	United States	100.00
Caesar Oil Pipeline Company, LLC	United States	25.00[5]
Cleopatra Gas Gathering Company LLC	United States	22.00[5]
Marine Well Containment Company LLC	United States	10.00[5]
Woodside Energy (Foreign Exploration Holdings) LLC	United Kingdom	100.00
Woodside Energy (Trinidad Block 3) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 6) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 5) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 7) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 14) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 23A) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 23B) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 28) Limited	United Kingdom	100.00
Woodside Energy (Trinidad Block 29) Limited	United Kingdom	100.00
Woodside Energy (Bimshire) Limited	United Kingdom	100.00
Woodside Energy (South Africa 3B/4B) Limited	United Kingdom	100.00
Woodside Energy (Egypt) Limited	United Kingdom	100.00
Woodside Energy (Carlisle Bay) Limited	United Kingdom	100.00
Woodside Energy (Mexico) Limited	United Kingdom	100.00
Woodside Energía Servicios Administrativos, S. de R.L. de C.V.	Mexico	99.00[7]
Woodside Energía Servicios de México, S. de R.L. de C.V.	Mexico	99.00[7]
Woodside Energy (Mexico Holdings) LLC	United States	100.00
Operaciones Conjuntas, S. de R.L. de C.V.	Mexico	99.00[7]
Woodside Energía Holdings de México, S. de R.L. de C.V.	Mexico	99.99[7]
Woodside Petróleo Operaciones de México, S. de R.L. de C.V.	Mexico	99.00[7]
Woodside Energy (Australia) Pty Ltd	Australia	100.00
Woodside Energy (International Exploration) Pty Ltd	Australia	100.00
Woodside Energy (Bass Strait) Pty Ltd	Australia	100.00
Woodside Energy (Victoria) Pty Ltd	Australia	100.00
Woodside Energy Holdings LLC	United States	100.00
Woodside Energy (Trinidad-2C) Ltd	Canada	100.00
Woodside Energy (Canada) Corporation	Canada	100.00

1. 16.67% relates to BHPP's interest percentage in North West Shelf. As a result of the merger, the Group's interest percentage in the North West Shelf joint venture has increased to 33.34%.
2. 0.01% owned by Woodside Energy Investments Pty Ltd.
3. 0.03% owned by Woodside Energy Global Holdings Pty Ltd.
4. <0.01% owned by Woodside Energy Global Holdings Pty Ltd.
5. Investments in associates held by BHPP. Remaining interest externally owned.
6. Woodside Energy USA Operations Inc: 90% voting and 37.67% capital. Woodside Energy Holdings LLC: 10% voting and 62.33% capital.
7. Woodside Energy (Mexico Holdings) LLC: 0.01-1%.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 30 June 2022

E.4 Events after the end of the reporting period

Subsequent to period end, the following repayments and refinancing of interest-bearing liabilities were undertaken:

- Repaid $200 million of the Yucho 2022 Medium Term Note and $42 million of the JBIC facility.
- Refinanced and increased an existing committed undrawn syndicated facility by $800 million.
- Renewed 2 bilateral loan facilities of $300 million.

The Group also entered into an agreement to invest $10 million in String Bio Private Limited, the developer of a patented process for recycling greenhouse gases into products such as livestock feed.

On 7 August, the United States Senate passed the Inflation Reduction Act (IRA) which has subsequently been signed into law. This law will impose a minimum corporate tax on Adjusted Financial Statement Income (AFSI) from 2023 which could impact cash tax payments of the Group in the future. Given the IRS regulations have not yet been published, an assessment of the impact of this law has not yet been completed.

DIRECTORS' DECLARATION

For the half-year ended 30 June 2022

In accordance with a resolution of directors of Woodside Energy Group Ltd, we state that:

In the opinion of the directors:

a) the financial statements and notes of the Group are in accordance with the Australian *Corporations Act 2001*, including:

   giving a true and fair view of the Group's financial position as at 30 June 2022 and of its performance for the half-year ended on that date; and

   complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*; and

b) there are reasonable grounds to believe that Woodside Energy Group Ltd will be able to pay its debts as and when they become due and payable.

For the purposes of the UK Disclosure Guidance and Transparency Rules, the directors confirm that to the best of their knowledge:

a) the financial statements, prepared in accordance with applicable set of accounting standards, give a true and fair view of the assets, liabilities, financial position and profit or loss of Woodside Energy Group Limited and the undertakings included in the consolidation taken as a whole; and

b) the half-year report includes a fair review of the:

   i. important events that have occurred during the first six months of the financial year and their impact on the half-year financial statements;

   ii. principal risks and uncertainties for the remaining six months of the financial year; and

   iii. related party transactions that have taken place in the first six months of the financial year and that have materially affected financial position or performance during that period and any changes in the related party transactions described in the last annual report that could have a material effect on financial position or performance in the first six months of the financial year.

On behalf of the Board

R J Goyder, AO
Chairman
Perth, Western Australia
30 August 2022

M E O'Neill
Chief Executive Officer and Managing Director
Sydney, New South Wales
30 August 2022

Independent auditor's review report to the members of Woodside Energy Group Ltd

Report on the half-year financial report

Conclusion

We have reviewed the half-year financial report of Woodside Energy Group Ltd (the Company) and the entities it controlled from time to time during the half-year (together the Group), which comprises the condensed consolidated statement of financial position as at 30 June 2022, the condensed consolidated income statement, condensed consolidated statement of comprehensive income, condensed consolidated statement of changes in equity and the condensed consolidated statement of cash flows for the half-year ended on that date, significant accounting policies and explanatory notes and the directors' declaration.

Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the accompanying half-year financial report of Woodside Energy Group Ltd does not comply with the *Corporations Act 2001* including:

1. giving a true and fair view of the Group's financial position as at 30 June 2022 and of its performance for the half-year ended on that date, and

2. complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

Basis for conclusion

We conducted our review in accordance with ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity* (ASRE 2410). Our responsibilities are further described in the *Auditor's responsibilities for the review of the half-year 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 & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to the audit of the annual financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

Responsibilities of the directors for the half-year financial report

The directors of the Company are responsible for the preparation of the half-year 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 half-year financial report that gives a true and fair view and is free from material misstatement whether due to fraud or error.

PricewaterhouseCoopers, ABN 52 780 433 757
Brookfield Place, 125 St Georges Terrace, PERTH WA 6000, GPO Box D198, PERTH WA 6840
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Auditor's responsibilities for the review of the half-year financial report

Our responsibility is to express a conclusion on the half-year financial report based on our review. ASRE 2410 requires us to conclude whether we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including giving a true and fair view of the Group's financial position as at 30 June 2022 and of its performance for the half-year ended on that date, and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

A review of a half-year financial report consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

PricewaterhouseCoopers

PricewaterhouseCoopers

Justin Carroll — Perth
Partner — 30 August 2022

Anthony Hodge — Perth
Partner — 30 August 2022

Dividends

Ex-dividend date	8 September 2022		
Record date for the interim dividend	9 September 2022		
DRP election date	12 September 2022		
Date the dividend is payable	6 October 2022		
		Current period	**Previous corresponding period[1]**
Interim dividend – fully franked	US cents per share	109	30

None of these dividends are foreign sourced.

Net Tangible Assets (NTA) per ordinary security

	Current period US$	Previous corresponding period[1] US$
Net Tangible Assets (US$ per ordinary security)[2]	15.06	12.83

Details of Associates and Joint Venture Entities

	Percentage of ownership interest held at end of period or date of disposal	
Name of entity	**Current period**	**Previous corresponding period[1]**
North West Shelf Gas Pty Ltd	33.33%	16.67%
North West Shelf Liaison Company Pty Ltd	33.33%	16.67%
China Administration Company Pty Ltd	33.33%	16.67%
International Gas Transportation Company Limited	33.33%	16.67%
North West Shelf Shipping Service Company Pty Ltd	33.33%	16.67%
North West Shelf Lifting Coordinator Pty Ltd	33.33%	16.67%
Blue Ocean Seismic Services Limited	28.50%	28.50%
Iwilei District Participating Parties, LLC	14.96%	-
Caesar Oil Pipeline Company, LLC	25.00%	-
Cleopatra Gas Gathering Company LLC	22.00%	-
Marine Well Containment Company LLC	10.00%	-

Shareholder information

Key announcements 2022

January	Woodside completes Pluto Train 2 sell-down to GIP
	Non-cash impairment reversal and other items
	Fourth quarter 2021 Report
	Woodside to withdraw from Myanmar
February	Full-year 2021 results
	Sustainable Development Report 2021
	Climate Report 2021
March	Court dismisses challenges to environmental approvals
	Processing of Pluto gas starts at North West Shelf
April	Supporting information for shareholder vote on merger released
	First quarter 2022 report
May	Woodside shareholders approve merger
	Woodside changes company name to Woodside Energy Group Ltd and ticker code change
June	Woodside completes merger with BHP Petroleum
	Admission to trading on the New York Stock Exchange
	Admission to trading on the London Stock Exchange

[1] Comparisons are to half-year ended 30 June 2021.
[2] Includes lease assets and liabilities as a result of AASB 16 *Leases*. This is an Alternative Performance Measure (APM) which is a non-IFRS measure that is unaudited but derived from auditor reviewed Half-year Financial Statements. This measure is presented to provide further insight into Woodside's performance. Refer to Alternative Performance Measures for a reconciliation of this measure to Woodside's financial statements on page 61-62 and Non-IFRS Measures on pages 65-66 for more information about non-IFRS measures.

	Bumi appeal dismissed
July	Second quarter 2022 Report
	2022 Production guidance clarification
August	Segment reporting restatement and other items

Events calendar 2022-2023

Key calendar dates for Woodside shareholders in 2022-23. Please note dates are subject to review.

August	30	Half-year 2022 results
September	8	Ex-dividend date for interim dividend
	9	Record date for interim dividend
	12	Dividend reinvestment plan election date
October	6	Payment date for interim dividend
	20	Third quarter 2022 report
December	1	Investor Briefing Day 2022
	31	Year-end 2022
January	25	Fourth quarter 2022 report

Business directory

Registered office:	**Postal address:**
Woodside Energy Group Ltd Mia Yellagonga 11 Mount Street Perth WA 6000 Australia	GPO Box D199 Perth WA 6840 Australia **T:** +61 8 9348 4000

Investor enquiries

Requests for specific information on the company can be directed to Investor Relations at:

Postal address:	
Investor Relations GPO Box D188 Perth WA 6840 Australia	**T:** +61 8 9348 4000 **E:** investor@woodside.com **W:** woodside.com

Share registry enquiries

Investors seeking information about their shareholdings should contact the company's share registry:

Registered office:	**Postal address:**
Computershare Investor Services Pty Limited Level 11 172 St Georges Terrace Perth WA 6000	GPO Box D182 Perth WA 6840 **T:** 1300 558 507 (within Australia) +61 3 9415 4632 (outside Australia) **E:** web.queries@computershare.com.au **W:** investorcentre.com/wds

The share registry can assist with queries on share transfers, dividend payments, the dividend reinvestment plan, notification of tax file numbers and changes of name, address or bank details.

Details of shareholdings can be checked conveniently and simply by visiting the share registry website at www.investorcentre.com/wds.

Details of our registrar in the United Kingdom and our authorised depositary bank for Woodside's American Depositary Receipt programme can be found on our website.

Assets

Producing facilities

Australia

Asset	Role	Equity	Product
Pluto LNG	Operator	90%	LNG, pipeline gas and condensate
North West Shelf	Operator	33.33%	LNG, pipeline gas, condensate and NGLs
Okha FPSO	Operator	50%	Crude oil
Ngujima-Yin FPSO	Operator	60%	Crude oil
Pyrenees FPSO	Operator	40-71.4%	Crude oil
Macedon	Operator	71.4%	Pipeline gas
Bass Strait	Non-operator	32.5-50%	Crude oil and condensate, pipeline gas and NGLs
Wheatstone Julimar-Brunello	Non-operator Operator	13% 65%	LNG, pipeline gas and condensate

International

Asset	Role	Equity	Product
Atlantis	Non-operator	44%	Crude oil and condensate, pipeline gas and NGLs
Mad Dog	Non-operator	23.9%	Crude oil and condensate, pipeline gas and NGLs
Greater Shenzi	Operator	72%	Crude oil and condensate, pipeline gas and NGLs
Greater Angostura	Operator	45-68.46%	Crude oil and condensate and pipeline gas

Developments

Australia

Asset	Role	Equity	Product
Scarborough[1]	Operator	100%	LNG, pipeline gas and condensate
Browse	Operator	30.6%	LNG, pipeline gas and condensate
Pyxis Hub	Operator	90%	LNG, pipeline gas and condensate
Greater Western Flank Phase 3	Operator	33.33%	LNG, pipeline gas and condensate

International

Asset	Role	Equity	Product
Sangomar Phase 1	Operator	82%	Crude oil
Mad Dog Phase 2	Non-operator	23.9%	Crude oil and condensate, pipeline gas and NGLs
Trion	Operator	60%	Gas and oil

[1] "Scarborough" includes the Scarborough, Jupiter and Thebe fields. Woodside is also operator of Pluto Train 2, which achieved FID in 2021, and holds a 51% participating interest.

Calypso	Operator	70%	Gas
Shenzi North	Operator	72%	Crude oil and condensate, pipeline gas and NGLs
Liard	Operator	100%	Gas
	Non-operator	50%	Gas
Wildling	Operator	100%	Crude oil and condensate, pipeline gas and NGLs
Sunrise	Operator	33.44%	LNG, pipeline gas and condensate
Myanmar A-6	Joint operator	40%	Withdrawing; handover in progress

Exploration

Asia-Pacific

Country	Permit	Role	Equity	Product
Myanmar[1]	A-7	Operator	Relinquished, formalities pending	Gas prone basin
	AD-7	Non-operator	Relinquished, formalities pending	Gas prone basin
	AD-1	Joint operator	Relinquished, formalities pending	Gas prone basin
	AD-8	Joint operator	To be relinquished on 30 September 2022, formalities pending	Gas prone basin
Republic of Korea	8, 6-1N	Joint operator	50%	Gas prone basin

Europe

Country	Permit	Role	Equity	Product
Ireland	FEL 5/13	Operator	100%	Oil or gas prone basin

Africa

Country	Permit	Role	Equity	Product
Senegal	Rufisque, Sangomar and Sangomar Deep	Operator	90%	Oil prone basin
Congo	Marine XX	Non-operator	22.5%[2]	Oil or gas prone basin
Egypt	Red Sea Block 1	Non-operator	45%	Oil or gas prone basin
	Red Sea Block 3	Non-operator	30%	Oil and gas prone basin
	Red Sea Block 4	Non-operator	25%	Oil and gas prone basin

[1] Woodside announced its decision to withdrawn from its interests in Myanmar on 27 January 2022.
[2] Effective July 2022.

Caribbean

Country	Permit	Role	Equity	Product
Barbados	Carlisle Bay, Bimshire Bay	Operator	100%[1]	Oil or gas prone basin
Trinidad & Tobago	TTDAA5 MDP[2]	Operator	65%	Gas prone basin

Latin America

Country	Permit	Role	Equity	Product
Peru	108	Non-operator	35%	Oil or gas prone basin

North America

Country	Permit	Role	Equity	Product
Canada (Offshore)	EL1157	Operator	100%	Oil or gas prone basin
	EL1158	Operator	100%	Oil or gas prone basin
US Gulf of Mexico	GB 640, GB 641, GB 685, GB 555, GB 556, GB 726, GB 770, GB 771, GB 604, GB 605, GB 647, GB 648, GB 649, GB 772, GB 728, GB 729, GB 773, GB 774, GB 421, GB 464, GB 465, GB 508, GB 509, GB 736, GB 780, GB 824	Non-operator	40%	Oil prone basin
	GB 630, GB 719, GB 720, GB 763, GB 807, GB 501, GB 502, GB 545, GB 676, GB 677, GB 721, GB 762, GB 805, GB 806, GB 851, GB 852, GB 895, GB 672, GB 716, GB 760	Operator	60%	Oil prone basin
	GC 282, GC 237	Non-operator	50%	Oil prone basin
	GB 574, GB 575, GB 619, DC 667, DC 802, DC 803, EB 655, EB 656, EB 699, EB 700, EB 701, AC 34, AC 35, AC 36, AC 78, AC 79, AC 80, EB 870, EB 871, EB 872, EB 914, EB 915, EB 742, EB 785, EB 786, EB 830, AC 125, AC 126, AC 127, AC 170, AC 39, AC 81, AC 82, AC 83, GC 564, GC 520	Operator	100%	Oil prone basin
	MC 798, MC 842	Non-operator	45%	Oil prone basin
	GC 679, GC 768	Non-operator	31.875%	Oil prone basin

[1] 40% working interest farm out to Shell subsidiary (BG) pending Ministry approval.
[2] Market Development Phase Area (MDP).

	GC 238	Non-operator	60%	Oil prone basin
	MC 368, MC 369, MC 411, MC 412, MC 455, MC 456	Non-operator	25%	Oil prone basin
	GC 80, GC 123, GC 124, GC 168	Operator	75%	Oil prone basin
	GC 738, GC 870	Non-operator	23.9%	Oil prone basin

Greenhouse gas assessment permits

Country	Permit	Role	Joint venture	Comment
Australia	G-7-AP	Non-operator	Bonaparte CCS Assessment Joint Venture	Located in the Bonaparte Basin off the north-western coast of the Northern Territory
	G-8-AP	Operator	Browse Joint Venture	For carbon capture and storage evaluation for Browse

Alternative Performance Measures

Woodside uses various Alternative Performance Measures (APM) which are non-IFRS measures that are unaudited but derived from auditor reviewed Half-Year Financial Statements. These measures are presented to provide further insight into Woodside's performance. See Non-IFRS Measures on pages 65-66 for more information.

APMs and their nearest respective IFRS measure.

APMs derived from Consolidated Income Statement	**30 June 2022 US$m**	30 June 2021 US$m
EBIT/EBITDA		
Net profit after tax	**1,679**	342
Adjusted for:		
Finance income	**(31)**	(12)
Finance costs	**86**	130
PRRT expense/(benefit)	**424**	(60)
Income tax expense	**824**	221
EBIT	**2,982**	621
Adjusted for:		
Oil and gas properties depreciation and amortisation	**924**	819
Amortisation of licence acquisition costs	**3**	2
Depreciation of lease assets	**62**	54
EBITDA	**3,971**	1,496
Underlying NPAT		
Net profit after tax attributable to equity holders of the parent	**1,640**	317
Adjusted for the following exceptional items:		
Add: Merger transaction costs	**424**	-
Add: Kitimat exit costs	-	33
Add: Port operations provisions	-	4
Less: Derecognition of the Corpus Christi onerous contract provision	**(245)**	-
Underlying NPAT	**1,819**	354

APMs derived from Consolidated Cash Flow Statement	**30 June 2022 US$m**	30 June 2021 US$m
Capital investment expenditure		
Capital additions on evaluation	-	124
Capital additions on oil and gas properties	**1,509**	596
Capital investment expenditure	**1,509**	720
Exploration expenditure		
Exploration and evaluation expenditure	**44**	90
Adjusted for:		
Amortisation expense	**(3)**	(2)
Prior year expense written off	-	(20)
Exploration expenditure	**41**	68
Free cash flow		
Cash flow from operating activities	**2,523**	1,333
Cash flow from/(used in) investing activities	**45**	(1,007)
Free cash flow	**2,568**	326

APMs derived from Consolidated Balance Sheet	30 June 2022 US$m	30 June 2021 US$m
Net tangible assets per ordinary security		
Net assets	**33,424**	13,161
Adjusted for:		
Goodwill	**(3,975)**	-
Non-controlling interest	**(790)**	(794)
Intangible assets	**(64)**	(2)
Net tangible assets	**28,595**	12,365
Number of issued and fully paid shares	**1,898,749,771**	963,579,886
Net tangible assets per ordinary security	**15.06**	12.83
Gearing		
Interest-bearing liabilities (Current and non-current)	**5,380**	5,467
Lease liabilities (Current and non-current)	**1,618**	1,234
Adjusted for:		
Cash and cash equivalents	**(4,615)**	(2,938)
Net debt	**2,383**	3,763
Equity attributable to equity holders of the parent	**32,634**	12,367
Total net debt and equity attributable to equity holders of the parent	**35,017**	16,130
Gearing (%)	**6.8**	23.3

Glossary

Term	Definition
$, $m	US dollars unless otherwise stated, millions of dollars
1P	Proved reserves
2C	Best Estimate of Contingent resources
2P	Proved plus Probable reserves
Brent	Intercontinental Exchange (ICE) Brent Crude deliverable futures contract (oil price)
Capital investment expenditure	Includes capital additions on oil and gas properties and evaluation capitalised
Cash margin	Revenue from sale of produced hydrocarbons less production costs, royalties, excise and levies, insurance, inventory movement, shipping and direct sales costs and other hydrocarbon costs; excludes exploration and evaluation, general administrative and other costs, depreciation and amortisation, PRRT and income tax
CCS	Carbon capture and storage
CCUS	Carbon capture utilisation and storge
cps	Cents per share
DRP	Dividend reinvestment plan
EBIT	Calculated as profit before income tax, PRRT and net finance costs
EBITDA	Calculated as profit before income tax, PRRT, net finance costs, depreciation and amortisation, impairment losses, impairment reversals
EPS	Earnings per share
Exploration expenditure	Includes exploration and evaluation expenditure less amortisation of licence acquisition costs and prior year exploration expense written off
FEED	Front-end engineering design
FID	Final investment decision
FPSO	Floating production storage and offloading
FPU	Floating production unit
Free cash flow	Cash flow from operating activities and cash flow from investing activities
Gearing	Net debt divided by the total of net debt and equity attributable to equity holders of the parent.
GHG or greenhouse gas	The seven greenhouse gases listed in the Kyoto Protocol are: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); nitrogen trifluoride (NF_3); perfluorocarbons (PFCs); and sulphur hexafluoride (SF_6)[1]
Gross margin	Gross profit divided by operating revenue. Gross profit excludes income tax, PRRT, net finance costs, other income and other expenses
GWF	Greater Western Flank
H1	H1 is 1 January to 30 June
HSE	Health, safety and environment
IFRS	International Financial Reporting Standards
JV	Joint venture
KGP	Karratha Gas Plant
Liquidity	Total cash and cash equivalents and available undrawn debt facilities
LNG	Liquified natural gas
Lower-carbon services	Woodside uses this term to describe technologies, such as CCUS or offsets, that may be capable of reducing the net greenhouse gas emissions of our customers
Net debt	Interest-bearing liabilities and lease liabilities less cash and cash equivalents
Net profit attributable to equity holders of the parent	Net profit after tax excluding non-controlling interests from the Group's operations.
Net tangible assets	The Group's net assets less goodwill, non-controlling interest and intangible assets

[1] See IFRS Foundation 2021: Climate Related Disclosures Prototype. Appendix A.

Net tangible assets per ordinary security	Net tangible assets divided by the number of issued and fully paid shares
New energy	Woodside uses this term to describe energy technologies, such as hydrogen and ammonia, that are emerging in scale but which are expected to grow during the energy transition due to having lower greenhouse gas emissions at the point of use than conventional fossil fuels
NPAT	Net profit after tax
NWS	North West Shelf
Offsets	Carbon offsets. Avoided GHG emissions, GHG emissions reduction or GHG removal and sequestration made available in the form of a carbon credit to counterbalance unabated/residual GHG emissions
PRRT	Petroleum resources rent tax
PSC	Production sharing contract
Revenue from ordinary activities	Revenue from the sale of hydrocarbons, processing and services revenue and shipping and other revenue.
RFSU	Ready for start-up
TRIR	Total recordable injury rate. The number of recordable injuries (fatalities, lost workday cases, restricted work day cases and medical treatment cases) per million work hours
Underlying NPAT	Net profit after tax from the Group's operations excluding any exceptional items
Unit production costs	Production costs ($ million) divided by production volume (MMboe)
USA	United States of America
USD	US dollars
WA	Western Australia

Conversion factors

Product	Unit	Conversion factor
Natural gas	5,700 scf	1 boe
Condensate	1 bbl	1 boe
Oil	1 bbl	1 boe
Natural gas liquids (NGLs)	1 bbl	1 boe

Units of measure

Term	Definition
bbl	barrel
boe	barrel of oil equivalent
Mbbl	thousand barrels
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
Bcf	billion cubic feet of gas
MMBtu	million British thermal units
MMscf	million standard cubic feet of gas
scf	standard cubic feet of gas

About this report

This Half-Year Report 2022 is a summary of Woodside's operations, activities and financial position as at 30 June 2022. Woodside Energy Group Ltd (ABN 55 004 898 962) is the parent company of the Woodside group of companies. In this report, unless otherwise stated, references to 'Woodside', 'the company', 'the Group', 'we', 'us' and 'our' refer to Woodside Energy Group Ltd and its controlled entities as a whole. The text does not distinguish between the activities of the parent company and those of its controlled entities.

References to 'H1' refer to the first half of the year, i.e. the period between 1 January 2022 and 30 June 2022. All dollar figures are expressed in US currency unless otherwise stated. Production and sales volumes, reserves and resources are quoted as Woodside share. A glossary of key terms, units of measure and conversion factors is on pages 63-64.

This report should be read in conjunction with the Annual Report 2021, Sustainable Development Report 2021 and the Climate Report 2021, available on Woodside's website, www.woodside.com.

Forward looking statements

This report may contain forward-looking statements with respect to Woodside's business and operations, market conditions, results of operations and financial condition, including, for example, but not limited to, statements about expectations regarding long-term demand for Woodside's products, timing of completion of Woodside's projects, adjustments to completion payments in respect of the BHPP merger, if any, expected synergies from the BHPP merger, future results of projects, operating activities, and new energy products, and expectations regarding the achievement of Woodside's scope 1 and 2 net equity emissions targets. All forward-looking statements contained in this report reflect Woodside's views held as at the date of this report. All statements, other than statements of historical or present facts, are forward-looking statements and generally may be identified by the use of forward-looking words such as '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. Similarly, statements that describe the objectives, plans, goals or expectations of Woodside are or may be forward-looking statements.

The information and statements in this report about Woodside's future strategy and other forward-looking statements are not guidance, forecasts, guarantees or predictions of future events or performance, but are in the nature of aspirational targets that Woodside has set for itself and its management of the business.

Those statements and any assumptions on which they are based are only opinions and are subject to change without notice and are subject to inherent known and unknown risks, uncertainties, assumptions and other factors, many of which are beyond the control of Woodside, its related bodies corporate and their respective Beneficiaries.

Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, fluctuations in commodity prices, 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, changes in accounting standards, economic and financial markets conditions in various countries and regions, political risks, project delay or advancement, approvals, cost estimates and the effect of future regulatory or legislative actions on Woodside or the industries in which it operates, including potential changes to tax laws, as well as general economic conditions, prevailing exchange rates and interest rates and conditions in financial markets.

Details of the key risks relating to Woodside and its business can be found in the "Risk" section of Woodside's most recent Annual Report released to the Australian Securities Exchange and in Woodside's filings with the US Securities and Exchange Commission. You should review and have regard to these risks when considering the information contained in this presentation.

If any of the assumptions on which a forward-looking statement is based were to change or be found to be incorrect, this would likely cause outcomes to differ from the statements made in this presentation.

Investors are strongly cautioned not to place undue reliance on any forward-looking statements. Actual results or performance may vary materially from those expressed in, or implied by, any forward-looking statements. None of Woodside nor any of its related bodies corporate, nor any of their respective beneficiaries, nor any person named in this presentation or involved in the preparation of the information in this presentation, makes any representation, assurance, guarantee or warranty (either express or implied) as to the accuracy or likelihood of fulfilment of any forward-looking statement, or any outcomes, events or results expressed or implied in any forward-looking statement in this presentation.

Past performance (including historical financial information and pro forma information) is given for illustrative purposes only. It should not be relied on and is not necessarily a reliable indicator of future performance, including future security prices.

Non-IFRS Measures

Certain parts of this report contain financial measures that have not been prepared in accordance with IFRS and are not recognized measures of financial performance or liquidity under IFRS. In addition to the financial information contained in this report presented in accordance with IFRS, certain "non-GAAP financial measures" (as defined in Item 10(e) of Regulation S-K under the U.S. Securities Act of 1933, as amended) have been included in this report. These measures include EBIT, EBITDA, Gearing, Underlying NPAT, Net debt, Free cash flow, Capital expenditure, Exploration expenditure, Net tangible assets, and Net tangible asset per ordinary security. These non-IFRS financial measures are defined in the glossary on pages 63-64 of this report. Refer to Alternative Performance Measures for a reconciliation of these measures to Woodside's financial statements on pages 61-62.

Woodside believes that the non-IFRS financial measures it presents 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 gross profit, net profit, cash flows from operating activities, or other figures determined in accordance with IFRS. In addition, such measures may not be comparable to similar measures presented by other companies.

Undue reliance should not be placed on the non-IFRS financial measures contained in this report, 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. You are urged to read carefully the auditor-reviewed Half-year Financial Statements and related notes thereto.

Other important information

All references to dollars, cents or $ in this presentation are to US currency, unless otherwise stated.

References to "Woodside" may be references to Woodside Energy Group Ltd or its applicable subsidiaries.

This report does not include any express or implied prices at which Woodside will buy or sell financial products.

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