COOPER ENERGY

ANNUAL REPORT FY24

PROUDLY PART OF AUSTRALIA'S ENERGY FUTURE.

We are proud to explore, develop and produce domestic gas for Australians to deliver shareholder value, support energy security and contribute to the wealth of our nation.

COOPER ENERGY LIMITED | ABN 93 096 170 295

The terms "the Company" and "Cooper Energy" are used in this Annual Report to refer to Cooper Energy Limited and/or its subsidiaries. The terms "2024", "FY24" and the "2024 financial year" refer to the 12 months ended 30 June 2024 unless otherwise stated. References to 2023, FY23 or 2025, FY25 refer to the 12 months ending 30 June of that year. References to information and events that occurred after 30 June 2024 are current as at 31 August 2024 unless otherwise stated. This Annual Report uses terms and abbreviations relevant to the company, its accounts and the petroleum industry. Information on abbreviations and terms, rounding and reserves and resources reporting is provided at the back of this report.

ACKNOWLEDGEMENTS

Cooper Energy recognises and acknowledges First Nations Peoples as the Traditional Owners and Custodians of the lands where we operate. We pay respects to the Elders past and present of the world's oldest living culture.

CONTENTS

CHAIRMAN'S FOREWORD

SUMMARY

The 2024 financial year was a period of change for Cooper Energy which saw operational successes, project challenges and renewal of the Board and management team. Our company is now on a strong footing to increase exposure to the East Coast domestic gas market and to execute its next phase of growth as a consequence of the strategic focus being driven by our Managing Director and her team.

Our Company continued its commendable health and safety performance in FY24, with a total recordable injury frequency rate (TRIFR) of 4.35 per million hours worked. While we have a target rate of zero, our TRIFR was well below the industry benchmark of 5.86, reflecting our unrelenting focus on a safe work environment for our employees.

FY24 was the first full year of Jane Norman's tenure as your CEO and Managing Director. Within a few short months of joining us, Jane reshaped the management of our Company, with greater clarity around accountabilities and responsibilities within the executive team and a sharper focus on operational success. The team working with Jane is well placed to deliver our new strategy in the interests of shareholders.

Pleasingly, our team's focus on improving operations at the Orbost Gas Processing Plant started to deliver production benefits through the year. Since July 2024, hardly a week has gone by without a new production-related record. Higher and more reliable production from Orbost is allowing us to generate record revenue and increased margins on greater volumes of spot gas sales and reduced production costs. Maximising production at Orbost remains a priority for FY25 and in September, for the first time in the Orbost plant's life, we recorded an average of 68 TJ/day for a full week, much to the great joy of the entire Company and all shareholders. I'm confident the dedication and focus of our team will result in further production improvements.

Completion of the Basker, Manta and Gummy wells decommissioning project was a major milestone for the company. Projects such as these carry serious operational, environmental and safety risks, so I am very pleased that no lost time injuries or significant environmental incidents occurred despite the more than 360,000 hours worked on the project. The project's cost was within the Company's revised guidance, although it was above our initial budget, largely due to issues out of the Company's control. This impacted the Company's debt position and the Company is focused on growing underlying cash generation to manage this in FY25 and beyond.

Importantly, over FY24 our Company began preparations for its next major growth project, the East Coast Supply Project (ECSP). The ECSP features low-risk exploration prospects and utilises our existing infrastructure to offer highly attractive returns and an accelerated development pathway. The Company's preferred three-well ECSP programme would provide one of the largest sources of new gas supply from 2028 onwards for the tight Southeast Australian gas market. The management team is working assiduously to progress funding, partnering and approvals workstreams to make this much-needed project a reality.

Our Company entered FY25 with a clear focus on improving shareholder returns by increasing production into a tight market, maximising our operational leverage and de-risking growth.

Importance of new gas supply

When it comes to gas in Australia, it is encouraging to see a change in the narrative from the media, regulators and legislators. There is recognition that gas will play a very important role through the energy transition and beyond, and that the lack of new local supply into Southeast Australia creates risks to that transition. Without new local gas supply, Southeast Australian consumers will be forced to rely on higher-cost and higher-emissions gas diverted from Queensland and/or imported as LNG.

Millions of Australians rely on affordable natural gas every day in their homes and for their jobs. Gas is essential in the production of everyday products like bricks and glass and for reliable electricity supply. Our Company is one of few able to help address looming gas shortages in Southeastern Australia with low-cost, local supply.

Higher and more reliable production from Orbost is allowing us to generate record revenue and increased margins on greater volumes of spot gas sales and reduced production costs.

Board renewal

I am delighted to welcome two new directors to your Board with the appointments of Mr Gary Gray AO and Mr Frank Tudor. Each is offering themselves to shareholders for election at the Annual General Meeting (AGM) in November and I commend them to you. Each of them brings outstanding expertise and I am very confident each will be effective in helping the company to maximise shareholder value as we play our part in the nation's energy transition. Full details of the impressive experience and accomplishments of Gary Gray and Frank Tudor can be found in the AGM Notice of Meeting.

I acknowledge also Mr Jeff Schnieder, who recently advised the Board that he will retire at our upcoming AGM. Jeff is the Company's longest serving board member, having overseen a transformative period in the Company's history. At all times Jeff brought an inquisitive mind and helpful insights to our discussions. I thank Jeff most sincerely for his service and extend to him and his wife our best wishes in his retirement.

Following Jeff's retirement and the appointment of the new directors, the average tenure of directors on the Board will be less than four years. The Board will also be genuinely diverse, not just in gender but also in background, experience and thought.

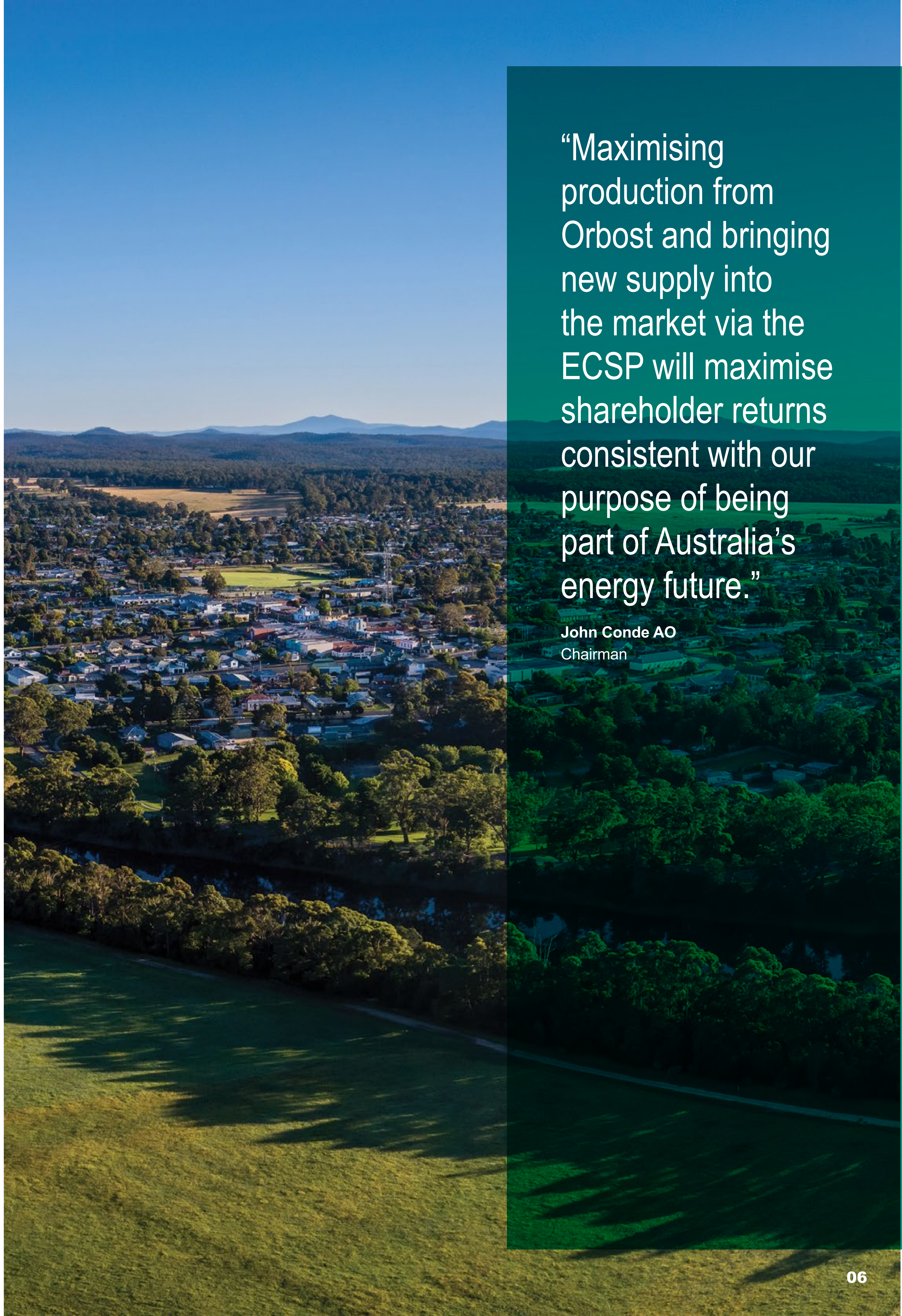
Jeff's departure will leave me as the longest-serving director on the Board. My current term expires in 2025. While my enthusiasm for the company remains undiminished, buoyed by the successes we have had in various operational areas in the last 12 months, the Board will continue to reflect on its composition to ensure it remains contemporary in the best interests of shareholders.

IN CONCLUSION

On behalf of the Board, I express my appreciation to shareholders for their loyalty and look forward to the Company's delivering its promises in FY25. With your Company having come through many challenges during the past few years, we now look forward to realising our potential. Maximising production from Orbost and bringing new supply into the market via the ECSP will maximise shareholder returns consistent with our purpose of being part of Australia's energy future. I thank all Cooper Energy staff for their hard work and persistence.

The Company's long-term strategy is appropriate, and we look forward to working in the interests of shareholders in FY25 and beyond.

John Conde AO
Chairman



MANAGING DIRECTOR'S REPORT

Financial year 2024 has been a pivotal year for our business: demonstrating delivery against our commitments, refreshing the Executive team and rolling out our new Vision, Strategy, Purpose and Values.

Our new Purpose, "Proudly part of Australia's Energy Future", is founded on the critical role that domestically produced natural gas plays in the Australian economy. Supported by our new Values: Think Differently, Deliver Together and Act Responsibly, these changes articulate the shift of our company culture to be more performance and delivery focused.

The market opportunity for our business remains stronger than ever. Gas is central to Australia's way of life. It is used for cooking and heating in our homes, to firm variable renewables in power generation and in the manufacturing of everyday, essential products, such as food packaging, fertilisers and construction materials. The Australian Government's Future Gas Strategy, released in May, recognises the criticality of natural gas, and the importance of supporting the timely development of gas supply in existing basins, such as our positions in the Otway and Gippsland Basins. The growing need for more gas supply is translating into stronger market pricing. Combined with stronger production in the Gippsland Basin, this resulted in the company generating record revenue, record underlying EBITDAX and record adjusted cash from operations.

FY24 IN REVIEW

Health, safety and environment

We have now been the operator of both the Athena Gas Plant (AGP) and the Orbost Gas Processing Plant (OGPP) for a full year and I am pleased to report that we have maintained our strong health and safety record, and exceptional environmental performance through FY24. This is especially meaningful in a year when we completed such a significant offshore decommissioning project that tripled our normal worker hours during execution. We improved slightly on FY23, with a Total Recordable Injury Rate of 4.35 (FY23: 4.38), and continue to track ahead of the industry benchmark of 5.86 (FY23: 5.68). Disappointingly, we did have a lost-time injury at OGPP, where one of our operators injured his finger during a routine maintenance task. We conducted a full investigation into the incident to ensure that we learn from it, including putting measures in place to prevent it from reoccurring. Thankfully, our operator has made a full recovery. We will continue to strive for continuous improvement in health, safety and environmental performance, to ensure that all our people go home safely from work.

In the past year, we have also progressed physical emissions reduction across our operated assets, delivering opportunities that reduce our emissions by approximately 4,000 tonnes of carbon dioxide equivalent. This has an additional benefit in reducing the number of credits required to maintain our carbon neutral position.

Plant performance improvement

We have delivered improved production performance across both plants. OGPP production increased by 5.5% year-on-year, despite power generator reliability issues and pipeline constraints that we faced in the last quarter of the year. With these issues now resolved, we have demonstrated our ability to push OGPP to its nameplate capacity through early FY25, reflecting the improvements we have made at the facility since taking over as operator in May 2023.

At AGP, we have reduced reliability loss from 12% in FY23 to 3% in FY24, with zero reliability loss in May and June. As discussed at our Investor Briefing in June, we are aiming to achieve less than 2% reliability loss across both facilities by the end of FY26.

BMG wells decommissioning

As announced in May, we completed the decommissioning of seven offshore oil wells in the Basker, Manta and Gummy (BMG) fields in the Gippsland Basin, clearing this liability from our balance sheet. I am proud of the way the decommissioning program was technically executed, and its success is testament to the hard work and dedication of our team and our service partners. The work program was completed with an exemplary health, safety and environmental record – with no lost-time injuries and no reportable or notifiable environmental incidents across more than 360,000 worker hours. The scale of the BMG program was significant in the history of decommissioning work in Australia, a reflection of the first-class capability of our work force.

With this hurdle cleared, we can now turn our attention to exploring the 1.3 trillion cubic feet (Tcf) of prospective resources[1] in the Gippsland to ensure we have backfill and growth for OGPP into the 2030s and beyond.

Positioning for growth

In June 2024, we rolled out our refreshed Vision and strategy, clearly defining our commitment to continue delivering affordable, reliable, locally-sourced and lower-emissions[2] gas to Australians. Our tier 1 resources, close to established infrastructure and the Southeast Australian market, is a core element of our competitive advantage. Over the last 10 years, we have shifted our business into domestic gas, targeting these premium domestic markets. Our growth strategy is to now leverage the unique infrastructure position that we have established, respecting the capital that has been invested in the business by our shareholders, enabling us to grow both value and volume. With stable, reliable production as our foundation, we now look forward to developing our East Coast Supply Project, a significant opportunity to increase production through AGP by more than four times. At a potential 90 terajoules a day, it is one of the largest new sources of supply for the Southeast domestic market and we have strong customer support for this economically attractive project

As previously announced, we are participating in a rig consortium which is expected to bring a rig into the region around the middle of calendar year 2025, setting the timeline for drilling. Our preferred programme is to drill 3 wells on a 50% basis, targeting first gas by 2028. This project could deliver more than 350 Bcf[3] of mean, unrisked resource potential, with a 98% chance of at least one gas discovery at Elanora, Isabella or Juliet.

Cost out / Transformation

In FY24, we have realised more than $10 million in annualised savings, with approximately 85% of identified initiatives completed within the year. This program has delivered our commitment to reduce General & Administrative (G&A) costs by at least 10%, achieving a 24% reduction in FY24 compared to FY23.

We aim to maintain this momentum through an ongoing continuous improvement program through FY25, focusing on streamlining business processes and systems, reducing contractor services costs through shorter OGPP absorber cleaning times and further increasing the time between absorber cleans, and lower waste management costs.

FY25 OUTLOOK

In FY25, our priority will be on further margin enhancement, maximising cash generation and paying down debt ahead of our major growth spending.
This will be driven by:

- Continued performance improvement at Orbost and improving reliability across both OGPP and AGP.
- Increasing our realised gas prices through increasing our exposure to the tight spot market and supplying customers with gas when they need it most, particularly during peak power generation demand periods.
- Maintaining focus on the lower cost base that we have delivered through our Transformation program and driving a mindset of continuous improvement to keep identifying opportunities to do things better, reduce costs and improve productivity.
- Focusing on energy efficiency and reducing waste and emissions at our plants. This not only maximises our sales gas volumes but will help to position us as an operator of choice for third-party gas volumes.
- Lastly, we will continue to progress the East Coast Supply Project, with the aim of locking in a partner for our preferred 3-well drilling program, in preparation for arrival of the rig.

CONCLUDING REMARKS

As we have consistently said, we believe gas is not just a transition fuel, it will increasingly be required to support Australia's net-zero targets and integration of renewable energy in the future. Australian manufacturers, businesses and homes continue to need access to reliable, low emissions and affordable gas. Domestic gas from existing basins, leveraging existing infrastructure, is the lowest cost, lowest emission supply to meet this demand. Over FY24, the need for more gas now and in the longer term, especially in our target markets, has become clearer to the Australian and State Governments, the Australian Energy Market Operator and other independent market analysts. Without gas, Australia cannot ensure reliable and affordable energy for householders and businesses or meet its climate objectives and deliver the energy transition.

We at Cooper Energy are uniquely positioned to supply affordable, reliable, locally-sourced and lower-emissions[2] gas to Southeast Australia and through this, deliver long-term, sustainable value to all shareholders, stakeholders, customers and the communities in which we live and work.

Thank you to our investors, the Board, the new Executive team, our staff and contractors, lenders, customers and suppliers for supporting our journey and success. I look forward to further progress in financial year 2025.

Jane Norman
Managing Director and CEO

[1]The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 15 May 2023 (Gummy Deep), 13 April 2022 (Wobbegong), and 4 May 2016 (Manta Deep and Chimaera East)
[2]Cooper Energy produces gas with lower Scope 1 and 2 emissions than alternative sources such as gas redirected from Queensland or imported as LNG, with Scope 1 and 2 emissions also fully offset using carbon credits
[3]The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and the net share of each prospect, were announced to ASX on 9 February 2022.

PROUDLY PART OF AUSTRALIA'S ENERGY FUTURE

THINK DIFFERENTLY

We innovate by keeping it simple while raising the bar. Nothing stops us from continually learning how to do things better and we move with pace.

DELIVER TOGETHER

Our clarity of purpose, can-do mindset and respect for each other means that anything is possible, and we are accountable to deliver our part.

ACT RESPONSIBLY

We know how to act responsibly and why it is important to work safely, keep our promises and act ethically with integrity in everything we do.

OUR BUSINESS

Cooper Energy is an Australian company providing energy exclusively for the domestic market.

Our headquarters are in Adelaide, with regional offices in Perth and Melbourne. We operate two gas processing facilities in regional Victoria, which process gas from offshore fields in the Otway and Gippsland basins.

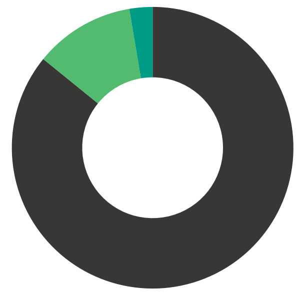
We have various non-operated interests in the South Australian Cooper Basin and in the onshore Otway basin in regional South Australia and Victoria.

FY24 Production: 62.1 TJe/day

- Gippsland Basin gas (49.5)
- Otway Basin gas & gas liquids (10.5)
- Cooper Basin oil (2.1)

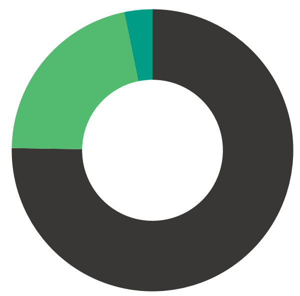
2P Proved & Probable reserves at 30 June 2024:
33.0 MMboe (201.6 PJe)

- Gippsland Basin (29.1 MMboe)
- Otway Basin (3.0 MMboe)
- Cooper Basin (0.9 MMboe)



2C Contingent Resources at 30 June 2024:
48.4 MMboe (at 30 June 2024)

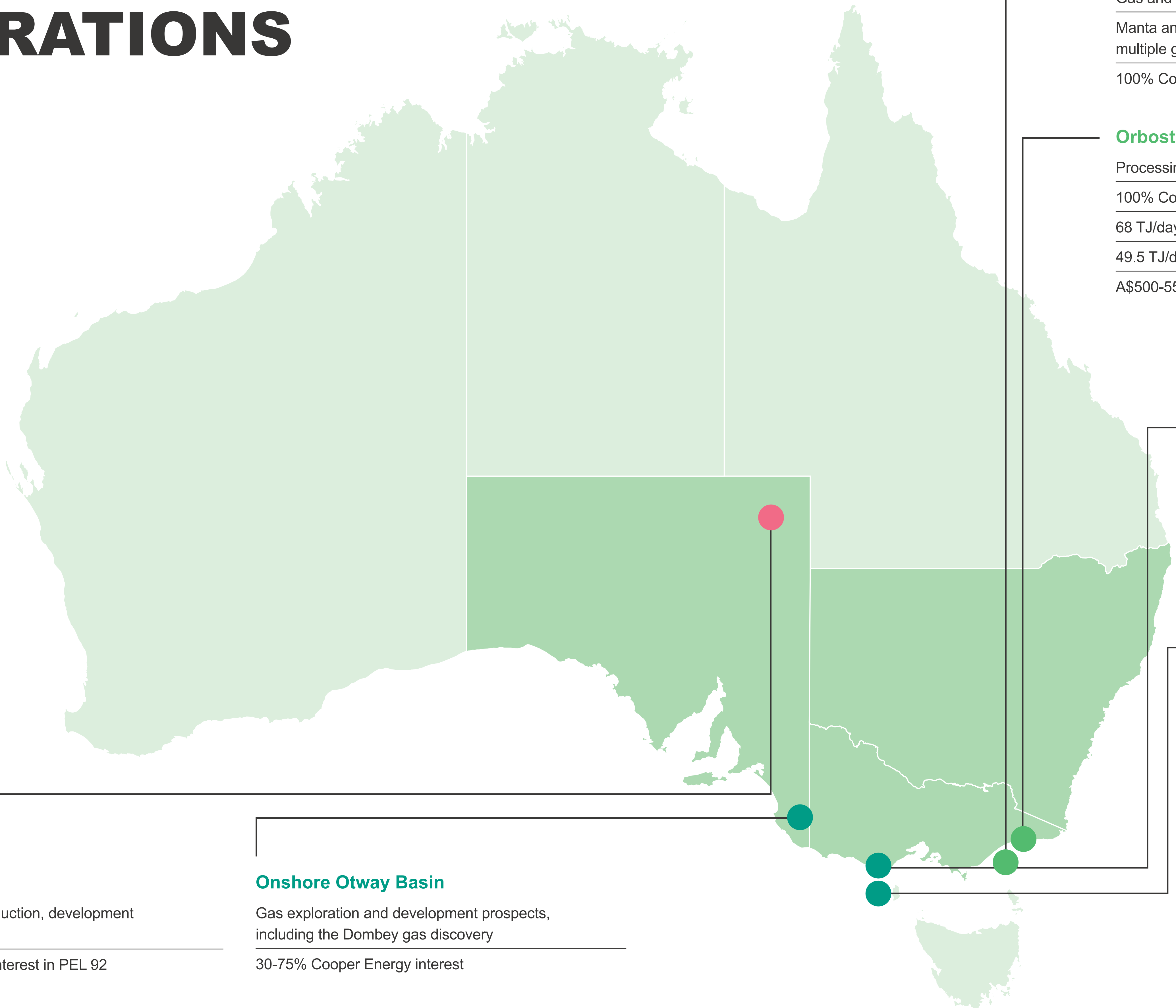
- Gippsland Basin (37.4 MMboe)
- Otway Basin (10.7 MMboe)
- Cooper Basin (0.3 MMboe)



OTHER KEY STATISTICS AT 30 JUNE 2024

Market cap	$594.0 million
Net debt	$250.7 million
Issued shares	2,640.0 million
Employee headcount	128

OUR OPERATIONS



Offshore Gippsland Basin

Gas and gas liquids production from the Sole field

Manta and Gummy gas and gas liquids resource and multiple gas exploration prospects

100% Cooper Energy interest

Orbost Gas Processing Plan

Processing hub for offshore Gippsland Basin gas

100% Cooper Energy interest

68 TJ/day capacity

49.5 TJ/day average production FY24

A$500-550mm estimated replacement value

Athena Gas Plant

Processing hub for Otway Basin gas

50% Cooper Energy interest

150 TJ/day capacity

21 TJ/day average production FY24 YTD

A$450-500mm estimated replacement value

Offshore Otway Basin

Gas and gas liquids production from the Casino, Henry and Netherby fields

Annie gas discovery and multiple exploration prospects

Preparing for the East Coast Supply Project

50% Cooper Energy interest in CHN

10% Cooper Energy interest in VIC/L21 (Minerva)

Cooper Basin

Western Flank oil production, development and exploration

25% Cooper Energy interest in PEL 92

Onshore Otway Basin

Gas exploration and development prospects, including the Dombey gas discovery

30-75% Cooper Energy interest

OUR SOCIAL & ENVIRONMENTAL COMMITMENT

HEALTH, SAFETY & ENVIRONMENT

Ahead of industry benchmark TRIFR[1]

~$60 MILLION

in purchases from SA and Victorian-based suppliers

CARBON NEUTRAL

Maintaining Climate Active Carbon Neutral Organisation certification[5]

HEALTH, SAFETY & ENVIRONMENT

No reportable[2] or notifiable[3] environmental incidents during the period

HEALTH, SAFETY & ENVIRONMENT

0 FATALITIES

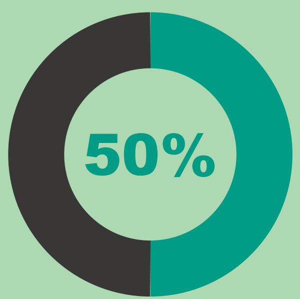
1 LOST TIME INJURY

CARBON NEUTRAL

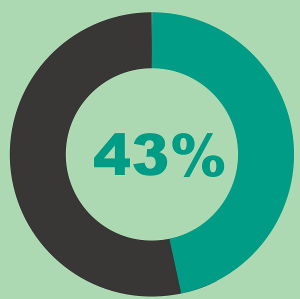
100%

SCOPE-1, SCOPE-2 & RELEVANT SCOPE-3 EMISSIONS OFFSET[4]

GENDER DIVERSITY



Female representation on the Board of Directors



Female representation on the Executive Leadership Team

>300 SUPPLIERS IN SA & VICTORIA

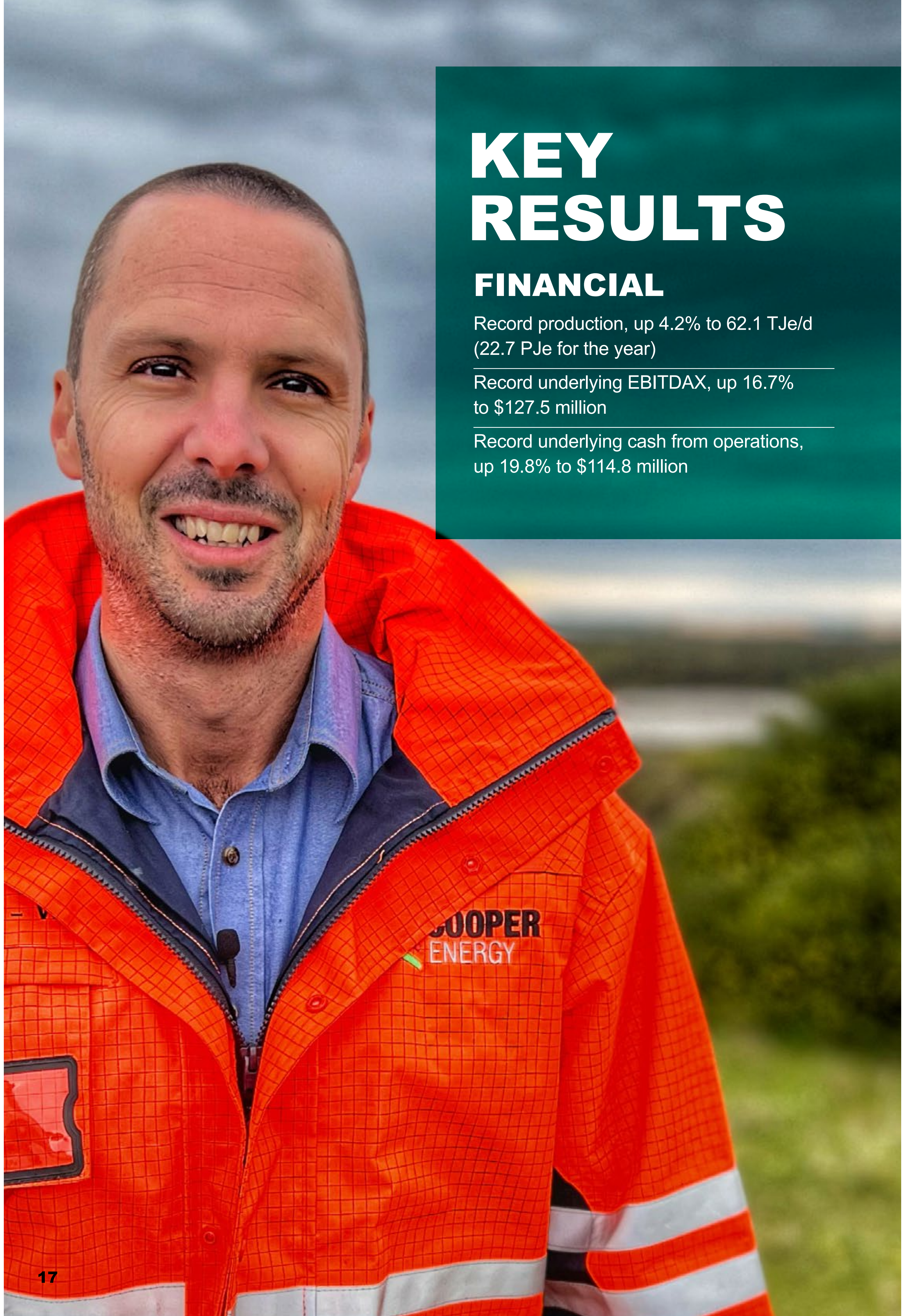
[1] NOPSEMA industry 12-month rolling average TRIFR for FY24

[2] As defined by Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009

[3] As defined by the Victorian Environment Protection Act 2017

[4] Organisational carbon emissions voluntarily offset according to Climate Active's scheme for FY24. These consist of Scope-1 (direct), Scope-2 (purchased electricity) and what Cooper has defined as its relevant Scope-3 emissions (embedded energy and business travel). Downstream Customer Scope-3 transportation and combustion emissions are not included. More information regarding Scope definition is available in the Cooper Energy 2024 Sustainability Report.

[5] Cooper Energy has been certified by Climate Active as a Carbon Neutral organisation for its Scope 1, Scope 2 and what Cooper Energy defines as its relevant Scope 3 emissions (e.g. embedded energy and business travel) for FY20-23. It is in the process of seeking FY24 certification. See the 2024 Sustainability Report for further information.



KEY RESULTS

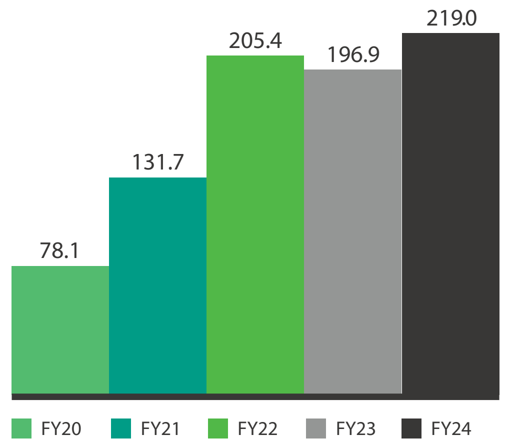
FINANCIAL

Record production, up 4.2% to 62.1 TJe/d (22.7 PJe for the year)

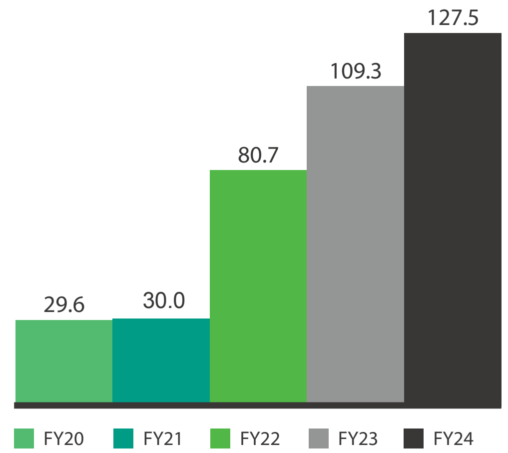
Record underlying EBITDAX, up 16.7% to $127.5 million

Record underlying cash from operations, up 19.8% to $114.8 million

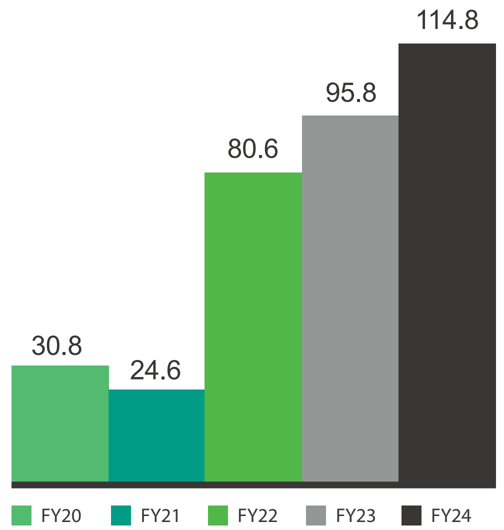
SALES REVENUE ($ million)



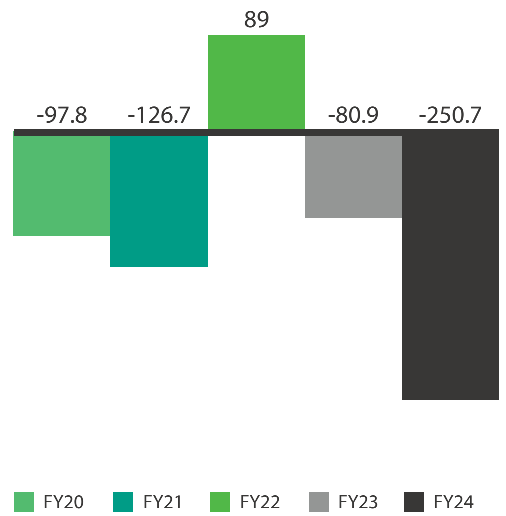
UNDERLYING EBITDAX ($ million)



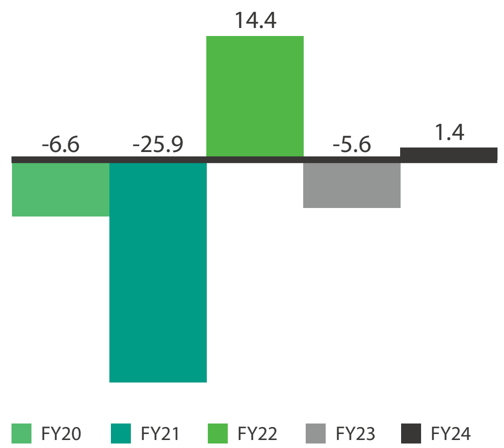
UNDERLYING CASH FROM OPERATIONS[1] ($ million)



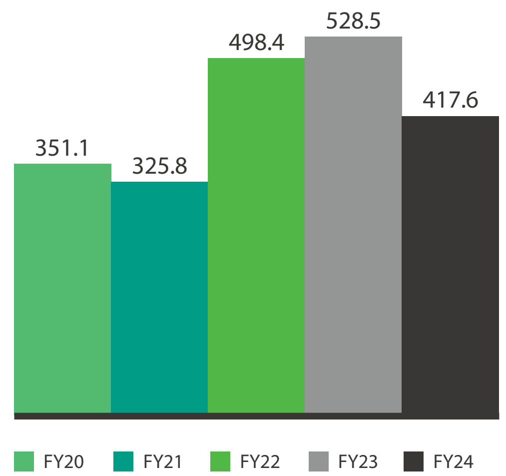
NET (DEBT)/CASH ($ million)



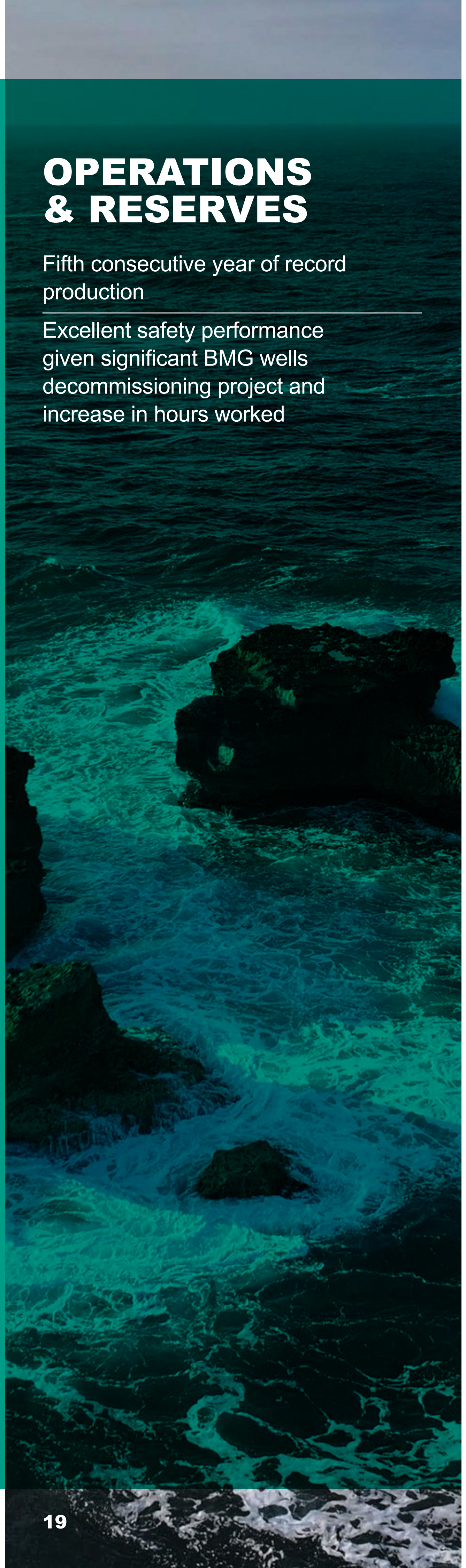
UNDERLYING NET PROFIT ($ million)



TOTAL EQUITY ($ million)



[1]Operating Cash Flow excluding restoration spend and other non-recurring and non-underlying items

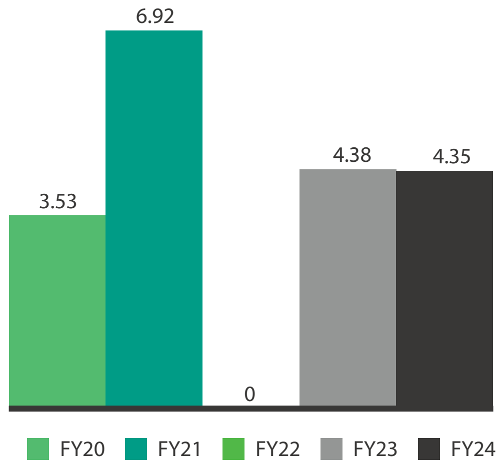


OPERATIONS & RESERVES

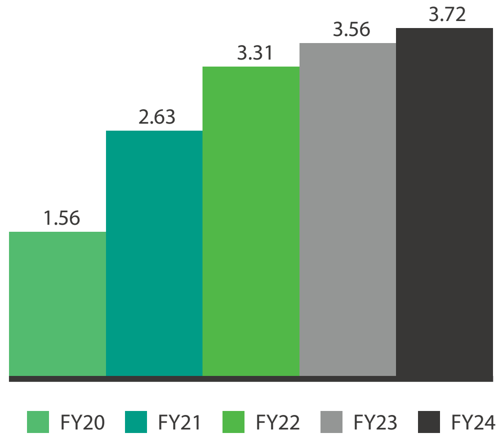
Fifth consecutive year of record production

Excellent safety performance given significant BMG wells decommissioning project and increase in hours worked

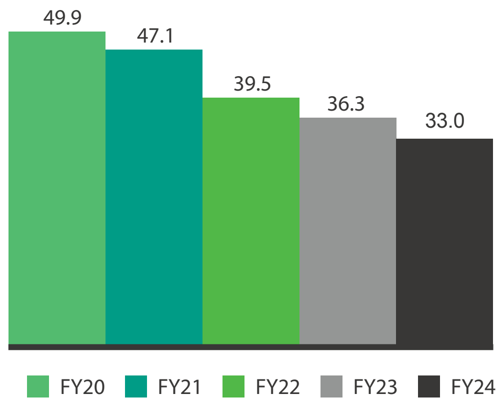
SAFETY (total recordable injury frequency rate)



PRODUCTION (MMboe)



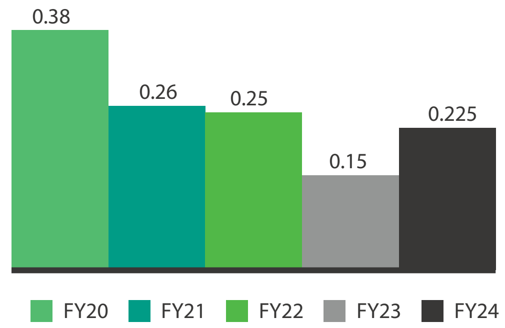
PROVED AND PROBABLE RESERVES (MMboe)[1]



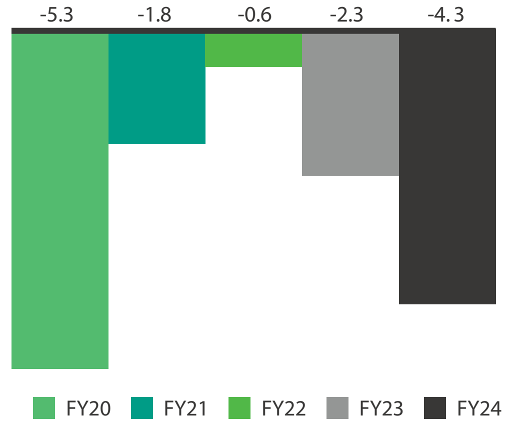
[1]As announced to the ASX on 23 August 2024

EQUITY

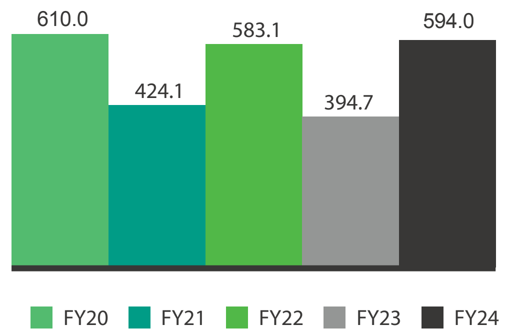
SHARE PRICE (dollars per share at 30 June)



BASIC EARNINGS PER SHARE (cents per share at 30 June)



MARKET CAPITALISATION ($million at 30 June)



GAS & OIL REVENUE

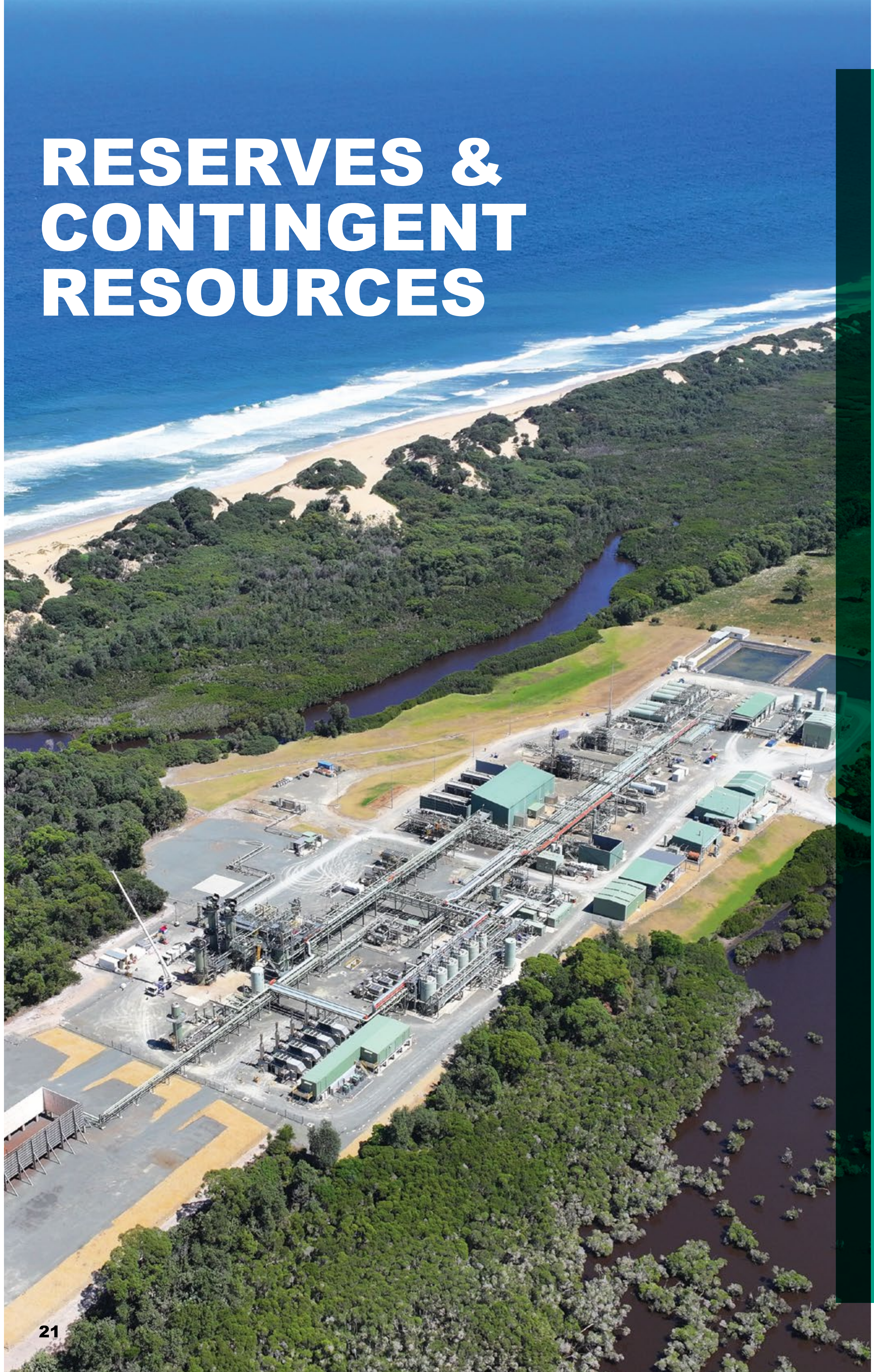
Gas	FY24	FY23	FY22
Total sales volume (PJ)	22.5	21.4	22.7
Average realised price ($/GJ)	8.83	8.59	8.29
Total revenue ($million)	198.5	184.0	188.1
2P Reserves (PJ)[1]	196.1	217.2	235.1

Oil and condensate	FY24	FY23	FY22
Total sales volume (kbbl)	146.8	91.5	126.6
Average realised price ($/bbl)	138.97	136.59	129.14
Total revenue ($million)	20.5	13.0	17.3
2P Reserves (MMbbl)[1]	0.9	0.8	1.1

CAPITAL EXPENDITURE

By activity ($million)	FY24	FY23	FY22
Exploration & appraisal	14.6	23.9	4.9
Development	9.3	17.3	14.6
TOTAL	**23.9**	**41.2**	**19.5**

By basin ($million)	FY24	FY23	FY22
Gippsland Basin	6.5	18.3	0.4
Otway Basin	10.6	17.8	15.3
Cooper Basin	6.0	4.2	3.3
Other	0.8	0.9	0.5
TOTAL	**23.9**	**41.2**	**19.5**



RESERVES & CONTINGENT RESOURCES

RESERVES

Cooper Energy's 2P gas and oil Reserves at 30 June 2024 are assessed to be 33.0 MMboe (201.6 PJe)[1].

[1]The conversion factor of 1 PJ = 0.163417 MMboe has been used to convert from sales gas (PJ) to oil equivalent (MMboe). The conversion factor 1 MMbbls = 6.11932 PJe has been used to convert oil (MMbbls) and condensate (MMbbls) to gas equivalent (PJe).

The key factors contributing to the reduction in Reserves since 30 June 2023 include:

- Production of 3.7 MMboe in FY24
- Upward revisions of 0.2 MMboe (2P) in the offshore Gippsland through updated history matching of the Sole gas field subsurface model
- Upwards revisions of 0.2 MMboe (2P) in the onshore Cooper Basin through the FY24 Bangalee South exploration discovery and revised field limits

RESERVES AT 30 JUNE 2024[1]

Category	Unit	1P Proved			2P Proved and Probable			3P Proved, Probable and Possible		
		Dev.	Undev.	Total	Dev.	Undev.	Total	Dev.	Undev.	Total
Sales gas	**PJ**	128.6	0.0	128.6	196.1	0.0	196.1	280.0	0.0	280.0
Oil + cond.	**MMbbl**	0.4	0.0	0.4	0.8	0.1	0.9	1.1	0.1	1.2
Total (2)	**MMboe**	21.4	0.0	21.4	32.9	0.1	33.0	46.9	0.1	47.0

[1]As announced to the ASX on 23 August 2024
[2]Reserves exclude Cooper Energy's share of future fuel usage. Totals may not reflect arithmetic addition due to rounding. The Reserves information displayed should be read in conjunction with the information in the Notes on calculation of Reserves and Contingent Resources provided in this document. "Cond." refers to condensate, "Dev." refers to developed reserves and "Undev." refers to undeveloped reserves

YEAR-ON-YEAR MOVEMENT IN 2P RESERVES

Category	Unit	Proved and Probable 2P Reserves			
		Cooper	Otway	Gippsland	Total
Reserves at 30 June 2023 (1)	**MMboe**	0.8	3.6	31.9	**36.3**
FY24 Production (2)	**MMboe**	-0.1	-0.6	-3.0	-3.7
Revisions/Acquisitions	**MMboe**	0.2	0.0	0.2	0.4
Reserves at 30 June 2024 (3)	**MMboe**	0.9	3.0	29.1	**33.0**

[1]As announced to the ASX on 25 August 2023
[2]Production from 1 July 2023 to 30 June 2024
[3]As announced to the ASX on 23 August 2024. Totals may not reflect arithmetic addition due to rounding.

CONTINGENT RESOURCES

Cooper Energy's 2C Contingent Resources at 30 June 2024 are 48.4 MMboe.[1] No material changes have occurred to the Contingent Resources since 30 June 2023.

[1]The conversion factor of 1 PJ = 0.163417 MMboe has been used to convert from sales gas (PJ) to oil equivalent (MMboe). The conversion factor 1 MMbbls = 6.11932 PJe has been used to convert oil (MMbbls) and condensate (MMbbls) to gas equivalent (PJe).

CONTINGENT RESOURCES AT 30 JUNE 2024[1]

	1C			2C			3C		
Category	**Gas**	**Oil/Cond**	**Total**	**Gas**	**Oil/Cond**	**Total**	**Gas**	**Oil/Cond**	**Total**
Basin	**PJ**	**MMbbl**	**MMboe**	**PJ**	**MMbbl**	**MMboe**	**PJ**	**MMbbl**	**MMboe**
Gippsland	100.9	2.5	19.0	198.9	4.9	37.4	365.0	9.7	69.3
Otway	43.9	0.0	7.2	64.7	0.1	10.7	83.9	0.1	13.8
Cooper	0.0	0.2	0.2	0.0	0.3	0.3	0.0	0.6	0.6
Total (2)	144.8	2.7	26.4	263.6	5.3	48.4	448.8	10.4	83.7

[1]As announced to the ASX on 23 August 2024
[2]Totals may not reflect arithmetic addition due to rounding. The Contingent Resources information displayed should be read in conjunction with the information in the Notes on calculation of Reserves and Contingent Resources provided in this document. "Oil/Cond" refers to oil + condensate resources.

YEAR-ON-YEAR MOVEMENT IN CONTINGENT RESOURCES

Category	Unit	1C	2C	3C
Contingent Resources at 30 June 2023 (1)	MMboe	26.4	48.4	83.7
Revisions	MMboe	0.0	0.0	0.0
Contingent Resources at 30 June 2024 (2)	MMboe	26.4	48.4	83.7

[1]As announced to the ASX on 25 August 2023
[2]As announced to the ASX on 23 August 2024. Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category. As a result, the 1C estimate may be conservative and the 3C estimate may be optimistic due to the effects of arithmetic summation.

Notes on calculation of Reserves and Contingent ResourcesCooper Energy prepares its petroleum Reserves and Contingent Resources in accordance with the definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

The estimates of petroleum Reserves and Contingent Resources contained in this Reserves statement are as at 30 June 2024. The Company is not aware of any new information or data that materially affects the estimates of reserves and contingent resources, and the material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed.

Unless otherwise stated, all references to Reserves and Contingent Resource quantities in this document are net to Cooper Energy.

Cooper Energy has completed its own estimation of Reserves and Contingent Resources for its operated Otway and Gippsland Basin assets. Elsewhere, Reserves and Contingent Resource estimations are based on assessment and independent views of information provided by the permit operators (Beach Energy Limited for PEL 92).

Reference points for Cooper Energy's petroleum Reserves and Contingent Resources and production are defined points where normal operations cease, and petroleum products are measured under defined conditions prior to custody transfer. Fuel, flare and vent consumed prior to the reference point is excluded.

Petroleum Reserves and Contingent Resources are prepared using deterministic, with support from probabilistic, methods. The Reserves and Contingent Resources estimate methodologies incorporate a range of uncertainty relating to each of the key reservoir input parameters to predict the likely range of outcomes.

Project and field totals are aggregated by arithmetic summation by category. Aggregated 1P and 1C estimates may be conservative and aggregated 3P and 3C estimates may be optimistic due to the effects of arithmetic summation.

Throughout this announcement, totals may not exactly reflect arithmetic addition due to rounding.

The conversion factor of 1 PJ = 0.163417 MMboe has been used to convert from sales gas (PJ) to oil equivalent (MMboe). Condensate and crude oil are converted at 1bbl = 1 boe. The conversion factor 1 MMbbls = 6.11932 PJe has been used to convert Oil (MMbbls) and condensate (MMbbls) to gas equivalent (PJe).

Reserves

Under the SPE PRMS 2018, "Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions".
The Otway Basin totals comprise the arithmetically aggregated project fields (Casino, Henry and Netherby). The Cooper Basin totals comprise the arithmetically aggregated PEL 92 fields. The Gippsland Basin totals comprise Sole Reserves only.

Contingent Resources

Under the SPE PRMS 2018, "Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies".

The Contingent Resources assessment includes resources in the Gippsland, Otway and Cooper Basins.

Qualified petroleum Reserves and Resources evaluator statement

The information contained in this report regarding Cooper Energy's Reserves and Contingent Resources is based on, and fairly represents, information and supporting documentation reviewed, prepared by, or under the supervision of, Mr James Clark who is a full-time employee of Cooper Energy Limited holding the position of Manager, Exploration & Subsurface. Mr Clark holds a Bachelor of Arts (Hons), a Doctorate in Geology, is a member of the American Association of Petroleum Geologists and the Society of Petroleum Engineers, is qualified in accordance with ASX listing rule 5.41, and has consented to the inclusion of this information in the form and context in which it appears.

REVIEW OF OPERATIONS

SAFETY

Detailed information regarding Cooper Energy's safety performance is provided in the 2024 Sustainability Report.

The 2024 Sustainability Report was published at the time of this Annual Report and can be viewed and downloaded from the Company's website.

Safety metrics

	FY24	FY23
Hours worked	689,398	228,482
Lost-time injuries (LTI)	1	0
Total recordable injury frequency rate (TRIFR)[1]	4.35	4.38
Industry TRIFR[2]	5.86	5.68

[1] TRIFR is recordable injuries (medical treatment injuries + restricted work case + lost time injuries + fatalities) per million hours worked. Calculated on a rolling 12-month basis

[2] Industry TRIFR is the NOPSEMA benchmark for offshore Australian operations; data is updated 3-monthly; published at www.nopsema.gov.au

PRODUCTION

Cooper Energy achieved record annual gas and oil production of 22.7 PJe in FY24, mainly due to increasing gas production from the Sole field in the Gippsland Basin.

	FY24			FY23		
	Gas (PJ)	Oil & Cond. (kbbl)	Total (PJe)	Gas (PJ)	Oil & Cond. (kbbl)	Total (PJe)
Gippsland Basin	18.1	-	18.1	17.2	-	17.2
Otway Basin	3.8	3.6	3.8	3.9	3.6	3.9
Cooper Basin	-	127.4	0.8	-	116.6	0.7
TOTAL	**21.9**	**131.0**	**22.7**	**21.1**	**120.1**	**21.8**

GIPPSLAND BASIN

Cooper Energy is the operator and 100% interest holder for all its Gippsland Basin interests. As at 30 June 2024, these interests comprised:

VIC/L32, which contains the Sole gas field;

VIC/RL13, VIC/RL14 and VIC/RL15, which contains the Basker, Manta and Gummy (BMG) gas and liquids field (these retention leases also hold legacy infrastructure associated with the BMG oil project);

VIC/RL16, which contains the shut-in Patricia-Baleen gas field and infrastructure which connects to the OGPP; and

Exploration permits VIC/P72, VIC/P75 and VIC/P80.

Orbost Gas Processing Plant

OGPP delivered an average gas processing rate of 49.5 TJ/d during FY24 (+5.5% on 47.1 TJ/d produced in FY23).

Production rates increased in H2 FY24 versus H1 FY24, largely due to the implementation of Orbost Improvement Project initiatives. Subsequent to FY24 year end, over July-August 2024, multiple records for Sole/OGPP production were set, including a record daily rate of 68 TJ, a 30-day average of 65.7 TJ/d, a 60-day average of 60.2 TJ/d and a 90-day average of 57.7 TJ/d.

The Sole gas field continues to perform in line with expectations.

Orbost Improvement Project

Numerous initiatives were implemented over FY24, focused on minimising foaming and fouling in the absorbers, increasing the time between absorber cleans and reducing the duration of cleans.

Workstreams undertaken included:
• reinstatement of the polisher unit;
• installation of heat tracing and insulation around the polisher unit;
• installation of an alternative spray distributor configuration in the absorber beds;
• installation of a mist eliminator;
• optimisation of the anti-foam agent pumps;
• trials of alternative packing material in the absorbers; and
• clean-in-place trials in the absorbers.

The polisher unit had a significant positive impact on production during the year. In late December 2023, a new type of polisher unit media was loaded and achieved a record life of nearly five months, four times longer than the previous record.

With the support of the polisher unit and other improvement initiatives, a record absorber runtime of six weeks between cleans was achieved over June - July 2024, compared to the previous typical absorber runtime of 2 - 3 weeks.

Work continues on identifying the root cause of the sulphur foaming and fouling issues in the sulphur absorber units. While this work is ongoing, the success of improvement programme initiatives to date, has allowed the plant to operate more consistently and at higher rates.

Further initiatives are being progressed to improve the reliability of the plant and maximise production rates, focusing on extending the time between absorber cleans and minimising the duration of the cleans.

With the recent production records, a decision has been made to no longer progress with the option to install a third absorber.

BMG wells decommissioning

During FY24, Cooper Energy decommissioned the former Basker, Manta and Gummy (BMG) wells. The work was primarily undertaken by the Helix Q7000 semi-submersible well intervention vessel.

Following delayed completion of the Tui field abandonment programme in New Zealand, the vessel departed New Zealand in late November 2023. BMG wells decommissioning operations commenced in late December 2023.

The late arrival of the Helix Q7000 at the BMG site resulted in the Company incurring more than three months of holding costs for the remaining contractor spread on the BMG programme. This delayed start, and additional time required for startup activities, consumed the budgeted contingency.

On 22 January 2024, the Company revised its mid-case cost estimate for the BMG wells decommissioning to approximately A$240-280 million, including a reasonable contingency for further non-productive time and adverse weather.

The BMG wells decommissioning programme was successfully completed in May. The programme incurred more than 360,000 person-hours with no lost time injuries and no significant environmental incidents. The success of the wells decommissioning project highlights the Company's commitment to health, safety, and the environment, as well as its strong engineering capability.

The total cost of the BMG wells decommissioning programme is expected to be slightly less than $270 million, with the final value subject to remaining invoice reconciliation. Decommissioning costs were funded from cash on hand, organic cash generation and the existing senior debt facility.

Cooper Energy continues to pursue its Victorian Supreme Court claim against PT Pertamina Hulu Energi ("Pertamina") for Pertamina's 10% share of the BMG decommissioning costs. These costs relate to decommissioning the seven wells as well as the related subsea infrastructure of the BMG oil project. From 2009 until 2014, Pertamina Hulu Energi Australia Pty Limited ("Pertamina Australia"), a wholly owned subsidiary of Pertamina, held a 10% interest in the BMG joint operating and production agreement ("JOA").

In February 2014, Pertamina Australia withdrew from the JOA.

A claim against Pertamina was filed by Cooper Energy in the Supreme Court of Victoria (the "Court"), in December 2022, seeking payment of an amount equal to 10% of the costs and expenses of the decommissioning operations incurred and to be incurred, pursuant to Pertamina Australia's obligations under the withdrawal and abandonment provisions of the JOA. Pertamina has been ordered by the Court to file its defence in September 2024.

Gippsland Basin farm-out

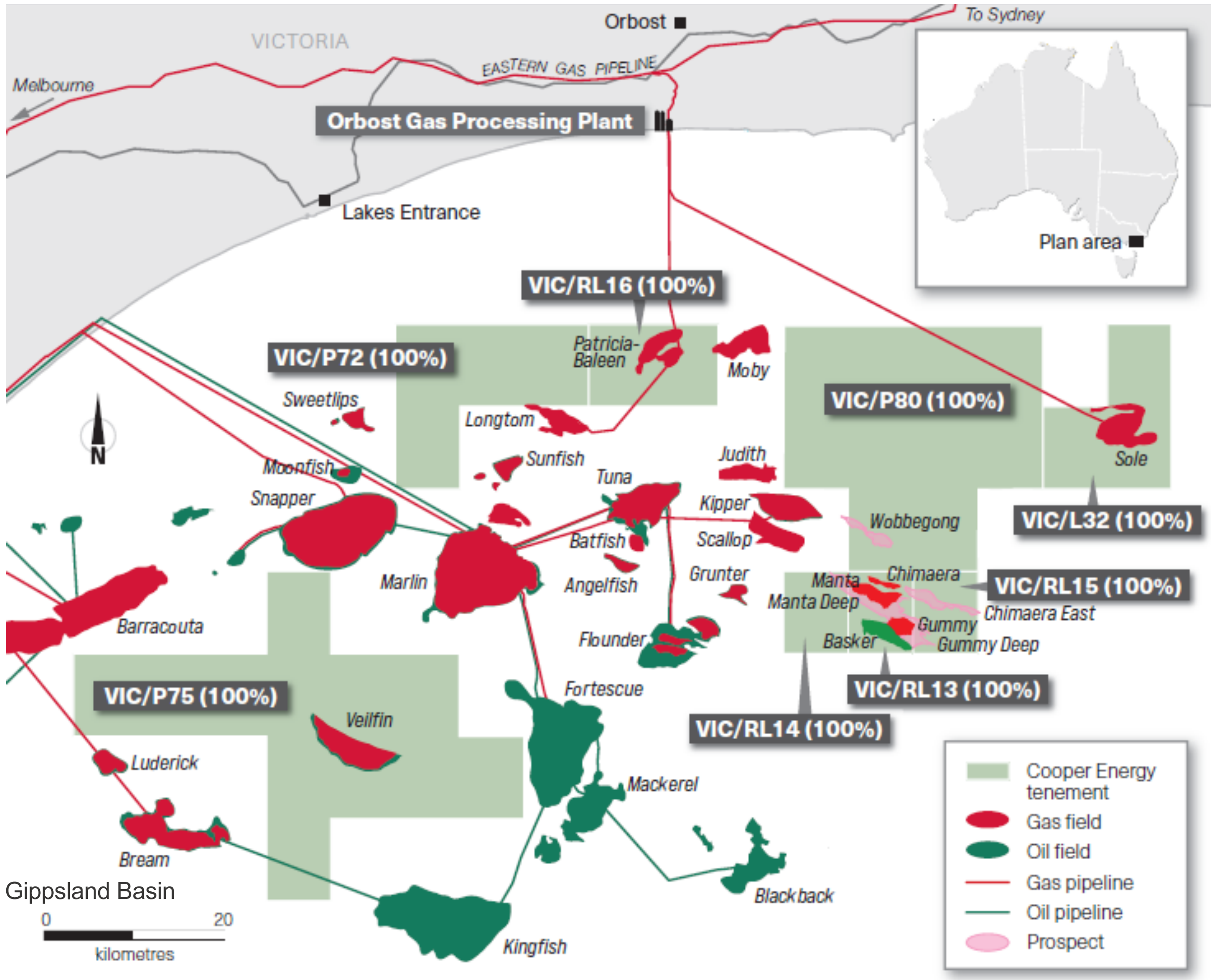
In May 2024, Cooper Energy commenced a process to bring a partner into VIC/P80 and VIC/L13,14 & 15 (Cooper Energy 100%) for the next Gippsland gas exploration and development phase.

The opportunity covers 185 PJ of 2C[1] discovered resource and more than 1.3 Tcf[2] of prospective resource. This brownfield project is expected to have a low cost to develop, a clear commercialisation pathway via existing infrastructure, and a relatively lower overall emissions profile compared to alternate sources, such as gas transported to Victoria from Queensland or imported LNG.

Gippsland Basin gas storage

In Q4 FY24 Cooper Energy commenced studying the potential repurpose of the shut-in Patricia Baleen field in VIC/RL16 (Cooper Energy 100%) for gas storage.

Cooper Energy tested the existing equipment, and the results of these tests are being integrated into the Company's assessment of gas storage potential.



[1] Contingent Resources for Manta gas and liquids announced to ASX on 12 August 2019, Contingent Resources for Gummy gas and liquids announced to ASX on 25 August 2023, 100% share
[2] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 15 May 2023 (Gummy Deep), 13 April 2022 (Wobbegong), and 4 May 2016 (Manta Deep and Chimaera East)

OTWAY BASIN (OFFSHORE)

The Company's interests in the offshore Otway Basin as at 30 June 2024 comprised:

a 50% interest in and operatorship of production licences VIC/L24 and VIC/L30 containing the producing Casino, Henry and Netherby gas fields, with the remaining 50% interest held by Mitsui E&P Australia and its associated entities ("Mitsui");

a 50% interest in and operatorship of production licences VIC/L33 and VIC/L34 containing part of the Black Watch and Martha gas fields, with the remaining 50% interest in these production licences held by Mitsui;

a 50% interest in and operatorship of exploration permit VIC/P44 containing the undeveloped Annie gas discovery, with the remaining 50% interest held by Mitsui;

a 100% interest in and operatorship of exploration permit VIC/P76;

a 50% interest in and operatorship of AGP (onshore Victoria), which is jointly owned with Mitsui and processes gas from the Casino, Henry and Netherby gas fields; and

a 10% non-operated interest in production licence VIC/L22, which holds the shut-in Minerva gas field, with Woodside Energy the operator and 90% interest holder.

Athena Gas Plant (AGP)

The AGP achieved an average gas processing rate of 10.4 TJ/d during FY24 (FY23: 10.7 TJ/d), both net to Cooper Energy's 50% share. Notable improvements in plant reliability were offset by natural decline in the Casino, Henry and Netherby (CHN) gas fields.

Low inlet pressure operations were successfully implemented in the beginning of CY2024, resulting in a production uplift of approximately 1 TJ/d on average. Well cycling operations continued to be implemented throughout the financial year to optimise production from the CHN fields.

Production in Q3 FY24 was impacted by a planned maintenance shutdown and additional unplanned compressor maintenance.

During Q4 FY24 AGP demonstrated stable operation with zero reliability loss over the two months of May and June.

East Coast Supply Project

Cooper Energy made significant progress on the East Coast Supply Project (ECSP), formally referred to as the Otway Phase 3 Development (OP3D), under which the Company intends to maximise the use of existing Otway Basin infrastructure to bring much-needed gas supply to Southeast Australia.

The ECSP developments can be connected to Cooper Energy's existing gas processing infrastructure at the AGP, which has ~150 TJ/d of total capacity (100% gross), with first gas targeted for 2028.

In Q1 FY24, as part of a consortium agreement with three other operators, the Company secured the Transocean Equinox rig for its drilling campaign in the Otway Basin. The Transocean Equinox is estimated to arrive in the Otway Basin in circa mid-CY2025. Within the consortium agreement, Cooper Energy has committed to one firm well and has options to drill additional development and/or exploration/appraisal wells.

Cooper Energy has evaluated a number of alternatives for the ECSP drilling and development campaign. The Company has focused on identifying the optimal campaign considering the size of prospects, the development's overall economic returns, scale of capital expenditure required and risk.

While Cooper Energy continues to evaluate ECSP alternatives, the Company is targeting a three-well programme on a 50% basis. This includes developing 64.8 PJ[1] in gross 2C resource (32.4 PJ net to Cooper Energy) through one well (Annie-2) and a two well exploration programme, with one planned geological sidetrack, targeting 358 Bcf[2] (179 Bcf net to Cooper Energy) of gross mean unrisked prospective resource potential.

Discussions with Mitsui, Cooper Energy's 50% joint venture partner in the Otway Basin, regarding the ECSP, are ongoing.

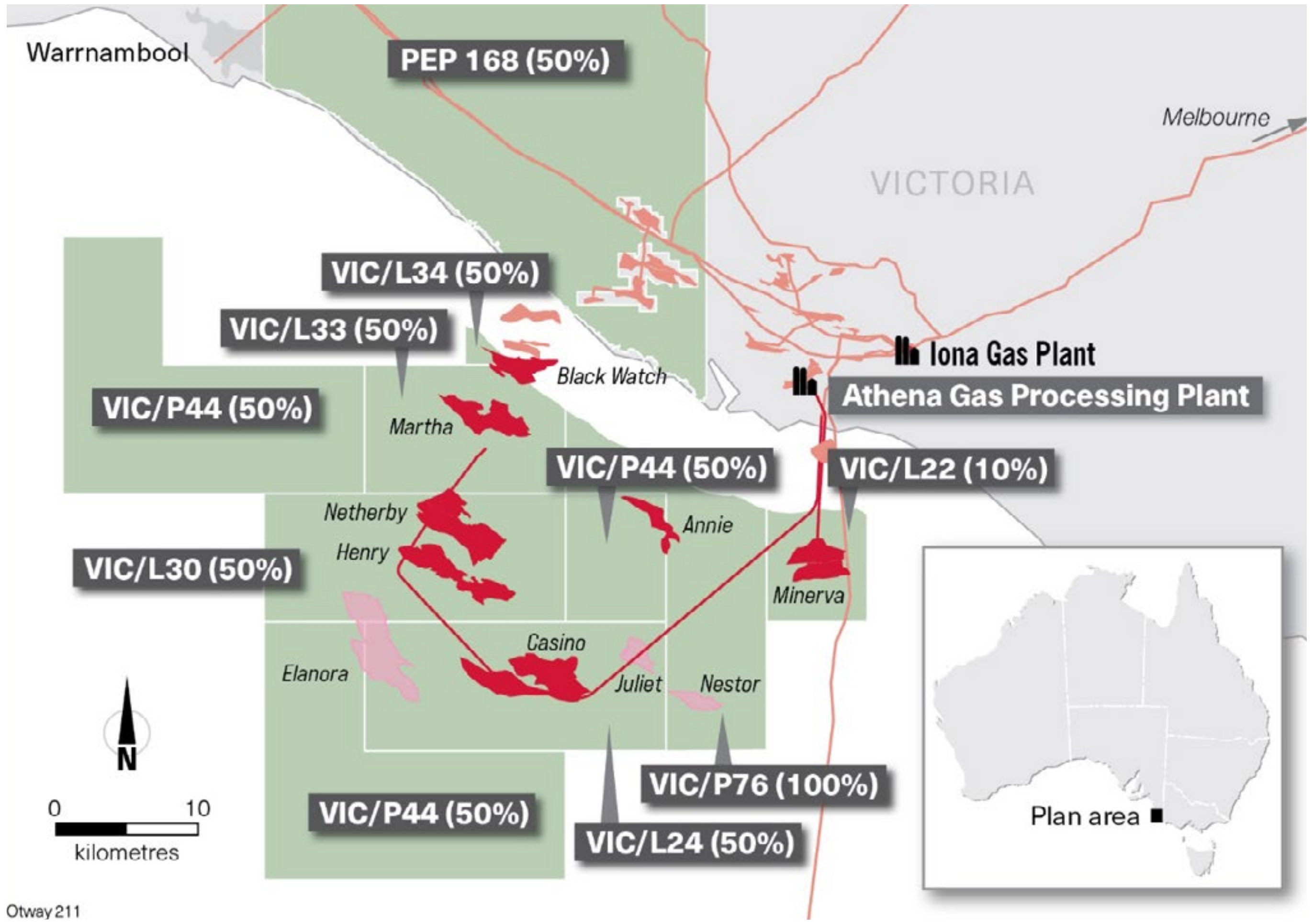
Cooper Energy expects to sanction the ECSP during FY25, at which time it will confirm the identity, number and timing of wells drilled as part of the programme. The Transocean Equinox is expected to commence drilling the first firm well of its campaign for Cooper Energy later in FY26.

The ECSP is expected to be funded from a range of sources including organic cash generation, the existing secured bank debt facility as well as the accordion debt facility of up to $120 million. Additionally, the Company continues to engage with several gas customers to support new domestic gas supply through a range of funding options, which could include prepayments.

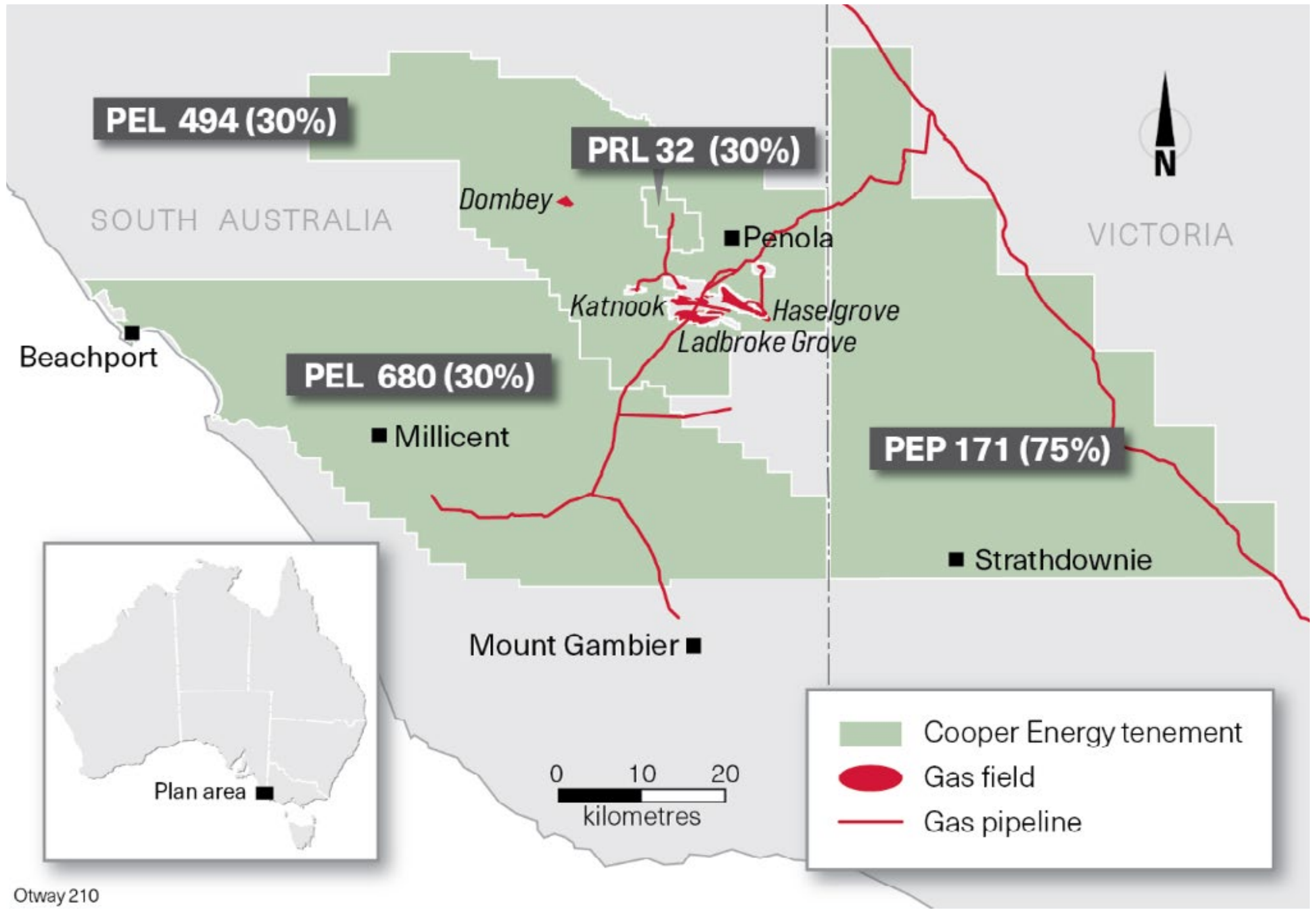
Minerva decommissioning

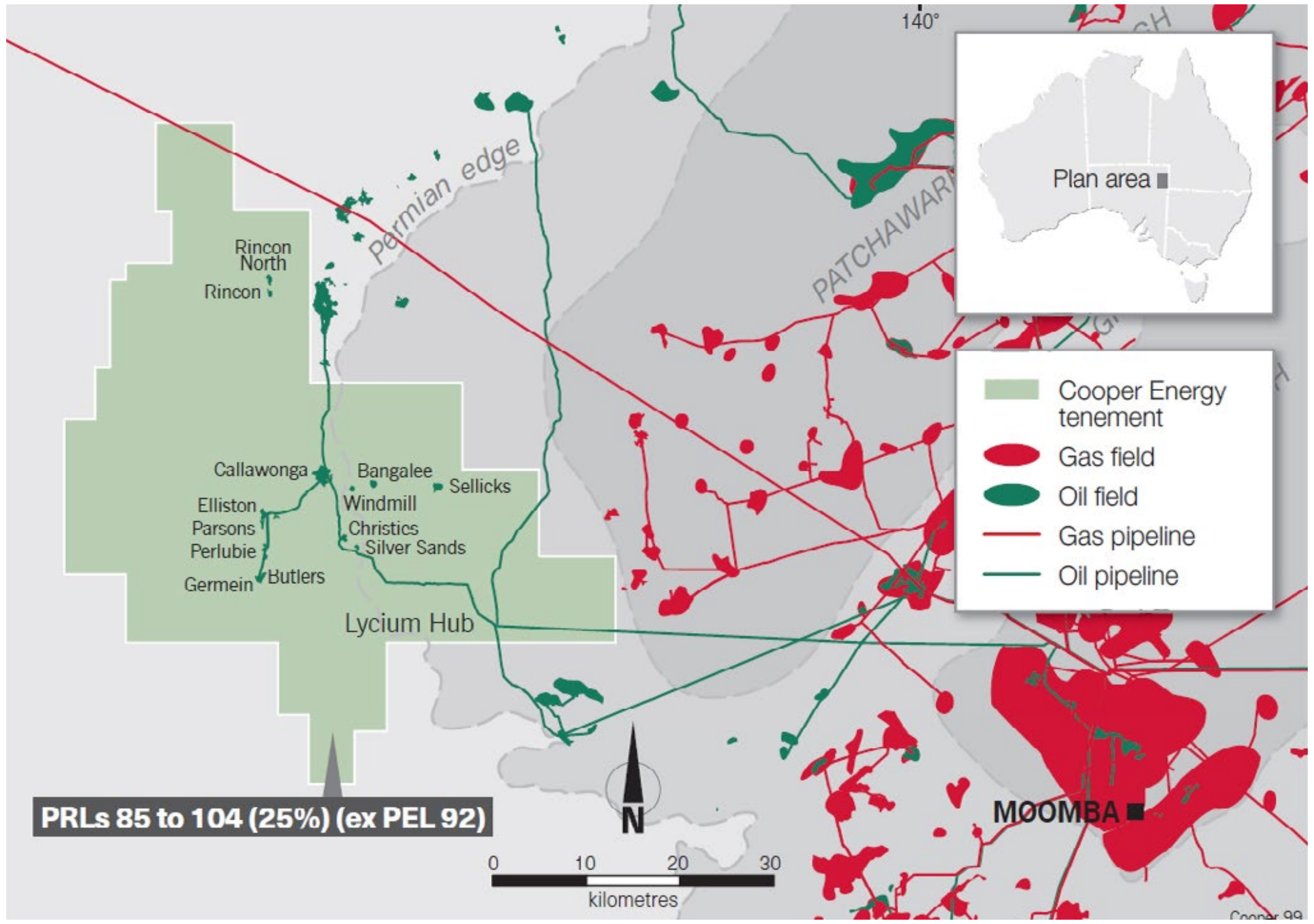
Woodside Energy, the Operator of VIC/L22 (Cooper Energy share 10%), will commence decommissioning of the Minerva gas field in late CY2024.

The subsea facilities (pipelines, umbilicals, etc.) will be removed first, followed by the subsequent decommissioning of the Minerva wells. The Transocean Equinox rig is estimated to arrive in the offshore Otway Basin region in circa mid-CY2025 and will commence the Minerva wells decommissioning shortly thereafter.



[1] Indicative only, not guidance. Projects are preliminary in nature and not yet sanctioned. Annie 2C resource is included on a gross basis as part of the Otway Basin 2C number in the FY24 Reserves and Contingent Resources ASX released on the 23 August 2024. See also Contingent Resource announcement: Annie Gas Field, 24 February 2020.
[2] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and the net share of each prospect, were announced to ASX on 9 February 2022.





OTWAY BASIN (ONSHORE)

The Company's interests in the onshore Otway Basin as at 30 June 2024 comprised:

a 30% interest in PEL 494, PRL 32 and PEL 680 in South Australia, with the remaining interests held by the operator, Beach Energy;

a 50% interest in PEP 168 in Victoria, with the remaining interest held by the operator, Beach Energy; and

a 75% interest in PEP 171 in Victoria, with the remainder held by operator Vintage Energy Limited.

Exploration activity

The PEL 494 Dombey 3D seismic survey was processed during H1 FY24 and interpreted during H2 FY24. Analysis to delineate the resource potential of the Dombey gas field and identify potential new exploration opportunities is ongoing and expected to be completed in H1 FY25.

Reprocessing of existing 3D seismic surveys within PEP 168 was conducted in H1 FY24, with several legacy 3D seismic datasets across PEP 168 reprocessed into one survey. Interpretation of this reprocessed seismic data was undertaken during the H2 FY24 and is ongoing to mature drilling prospects in the permit.

COOPER BASIN

The Company's interests in the Cooper Basin as at 30 June 2024 comprised a 25% interest in PRLs 85-104 (formerly PEL 92), with the remaining interests held by the operator, Beach Energy.

Exploration and development activity

Cooper Energy took part in a four well exploration drilling campaign in PRLs 85-104 (formerly PEL 92) in the first half of FY24.

The first exploration well, Marion 1, was drilled in September 2023 and was plugged and abandoned after failing to encounter hydrocarbons in the primary Namur Reservoir.

Bangalee South 1, located 630 metres southeast of Bangalee 1, was drilled in October 2023 and intersected 2.9 metres of net oil pay in the Namur reservoir and 4.3 metres of net oil pay in the Birkhead reservoir. The well was cased and suspended as a future oil producer. The Birkhead zone was brought online in December 2023, with initial production above 350 bbls/d (gross).

In October 2023, Wooley Rock 1 intersected 1.2 metres of net oil pay and was plugged and abandoned as a non-commercial discovery. Chadinga 1 was drilled in December 2023, approximately three kilometres northwest of the Wooley Rock discovery and was plugged and abandoned, having failed to encounter hydrocarbons.

TRANSFORMATION PROGRAMME

One of the Company's key priorities for FY24 was the execution of cost-out initiatives under the transformation programme, outlined during the FY23 full year results.

The transformation programme was all encompassing, targeting savings and efficiency across the entire business.

As at 30 June 2024, approximately $10.5 million in annualised forward-looking net savings has been realised, with over 100 initiatives identified across the business. Around 85% of the identified initiatives were completed or actioned by the end of FY24, with the full effect of cost savings and benefits realised into FY25 and beyond.

Significant savings in production costs were achieved across the business, in particular at OGPP. A large part of the savings related to cost of cleaning of the absorber beds, including renegotiating long standing contracts with third party contractors, as well as reducing the time and frequency of absorber cleans.

An additional focus area at OGPP was to reduce costs arising from the removal and disposal of solid sulphur and waste related to the treatment of gas. The Company is investigating beneficial reuse opportunities for the solid sulphur that is produced as a by-product at the plant and currently classified as waste. If successful, and in conjunction with more efficient waste disposal, the Company is targeting more than $2.0 million per year in additional savings from this initiative.

A 24% reduction in net G&A costs was achieved in FY24 vs FY23 on an annualised basis, or 36% net of restructuring and other non-recurring costs incurred.

$10.5 MILLION

annualised net savings realised (approx)

>100

initiatives identified across the business

24% REDUCTION

in net G&A costs on an annualised basis

PORTFOLIO

Cooper Energy Exploration & Production Tenements

GIPPSLAND BASIN

State	Tenement	Interest	Location	Area (km^2)	Operator	Activity
Victoria	VIC/P72	100%	Offshore	271	Cooper Energy	Exploration
	VIC/P75	100%	Offshore	808	Cooper Energy	Exploration
	VIC/P80	100%	Offshore	676	Cooper Energy	Exploration
	VIC/RL13 (Basker-Manta-Gummy)	100%	Offshore	67	Cooper Energy	Retention
	VIC/RL14	100%	Offshore	67	Cooper Energy	Retention
	VIC/RL15	100%	Offshore	67	Cooper Energy	Retention
	VIC/RL16	100%	Offshore	135	Cooper Energy	Retention
	VIC/L32	100%	Offshore	203	Cooper Energy	Production

OTWAY BASIN

State	Tenement	Interest	Location	Area (km^2)	Operator	Activity
South Australia	PEL 494	30%	Onshore	1,277	Beach Energy	Exploration
	PEL 680	30%	Onshore	1,929	Beach Energy	Exploration
	PRL 32	30%	Onshore	37	Beach Energy	Retention
Victoria	PEP 168	50%	Onshore	795	Beach Energy	Exploration
	PEP 171	75%	Onshore	1,974	Vintage Energy	Exploration
	VIC/P44	50%	Offshore	603	Cooper Energy	Exploration
	VIC/P76	100%	Offshore	162	Cooper Energy	Exploration
	VIC/L22 (Minerva)	10%	Offshore	58	Woodside Energy	Production
	VIC/L24 (Casino)	50%	Offshore	201	Cooper Energy	Production
	VIC/L30 (Henry & Netherby)	50%	Offshore	201	Cooper Energy	Production
	VIC/L33	50%	Offshore	128	Cooper Energy	Production
	VIC/L34	50%	Offshore	6	Cooper Energy	Production

COOPER BASIN

State	Tenement	Interest	Location	Area (km^2)	Operator	Activity
South Australia	PPL 204 (Sellicks)	25%	Onshore	2.0	Beach Energy	Production
	PPL 205 (Christies-Silver Sands)	25%	Onshore	4.3	Beach Energy	Production
	PPL 220 (Callawonga)	25%	Onshore	5.5	Beach Energy	Production
	PPL 224 (Parsons)	25%	Onshore	1.8	Beach Energy	Production
	PPL 245 (Butlers)	25%	Onshore	2.1	Beach Energy	Production
	PPL 246 (Germein)	25%	Onshore	0.1	Beach Energy	Production
	PPL 247 (Perlubie)	25%	Onshore	1.5	Beach Energy	Production
	PPL 248 (Rincon)	25%	Onshore	2.0	Beach Energy	Production
	PPL 249 (Ellison)	25%	Onshore	0.8	Beach Energy	Production
	PPL 250 (Windmill)	25%	Onshore	0.6	Beach Energy	Production
	PRL 85-104[1] (formerly PEL 92)	25%	Onshore	1,899.3	Beach Energy	Exploration

[1]Includes associated PPLs

DIRECTORS

MR JOHN C. CONDE AO

B.Sc. B.E(Hons), MBA

- Chairman

- Independent Non-Executive Director

Appointed 25 Feb 2013

Experience and expertise

Mr Conde has extensive experience in business and commerce and in chairing high profile business, arts and sporting organisations.

Previous positions include non-executive director of BHP Billiton (ASX:BHP), Chairman of Bupa Australia, Chairman of Pacific Power (the Electricity Commission of NSW), Chairman of the Sydney Symphony Orchestra, director of AFC Asian Cup, Chairman of Events NSW, President of the National Heart Foundation, Chairman of the Pymble Ladies' College Council and director of Dexus Property Group (ASX:DXS).

Current and other directorships in the last 3 years

Mr Conde is Chairman of The McGrath Foundation (since 2013 and director since 2012) and Chairman of Dexus Wholesale Property Fund (DWPF) (since 2020).

Mr Conde is a former President of the Commonwealth Remuneration Tribunal (2003 – 2023) and Deputy Chairman of Whitehaven Coal Limited (ASX:WHC) (2007 – 2022)

Special responsibilities

Mr Conde is Chairman of the Board of Directors. Effective 19 August 2021 he is also a member of the People & Remuneration Committee and is the Chairman of the Governance & Nomination Committee.

MS JANE L. NORMAN

B.Sc.,B.Eng.(Hons) PGDip, GAICD

Managing Director and CEO

Appointed 20 March 2023

Experience and expertise

Jane has worked and studied in Australia and the UK and brings 30 years of industry experience in the energy markets. She began her career with Shell International Exploration & Production as a Process Engineer in operations and then as a Commercial Advisor in The Hague, Aberdeen and London. Subsequently, in London, Jane held corporate finance and equity capital markets roles with Cazenove & Co (now JP Morgan Cazenove) and Goldman Sachs.

Jane returned to Australia to join Santos where she held senior commercial, corporate strategy and Executive Committee roles. She led major strategic initiatives at Santos and played a key role in Santos' growth strategy, in particular the merger with Oil Search.

During her time at Santos Jane helped drive the transformation of company performance, helping to establish the growth strategy focused on cash generation and shareholder returns and, more recently, the company's energy transition strategy. Jane holds a Bachelor of Science (Pure Mathematics and Chemistry) and Bachelor of Chemical Engineering (Hons) from the University of Sydney and a Graduate Diploma in Management and Economics of Natural Gas (Distinction) from the University of Oxford. Jane is a Graduate of the Australian Institute of Company Directors.

Current and other directorships in the last 3 years

Ms Norman is a director of the wholly owned subsidiaries of Cooper Energy Limited and is on the Board of the Australian Energy Producers (since 2023).

Special responsibilities

Ms Norman is Managing Director and CEO. She is responsible for the day-to-day leadership of Cooper Energy, and is the leader of the Executive Leadership Team.

MR TIMOTHY G. BEDNALL

LLB (Hons)

Independent Non-Executive Director

Appointed 31 March 2020

Experience and expertise

Mr Bednall is a highly experienced and respected corporate lawyer and law firm manager. He is a partner of King & Wood Mallesons (KWM), where he specialises in mergers and acquisitions, capital markets and corporate governance, representing public company and government clients. Mr Bednall has advised clients in the oil and gas and energy sectors throughout his career.

Mr Bednall was the Chairman of the Australian partnership of KWM from January 2010 to December 2012, during which time the merger of King & Wood and Mallesons Stephen Jaques was negotiated and implemented. He was also Managing Partner of M&A and Tax for KWM Australia from 2013 to 2014, and Managing Partner of KWM Europe and Middle East from 2016 to 2017. He was General Counsel of Southcorp Limited (which became the core of Treasury Wine Estates Limited) from 2000 to 2001.

Current and other directorships in the last 3 years

Mr Bednall is a board member of the National Portrait Gallery Foundation (since 2018) and a director of Pooling Limited (since 2017).

Special responsibilities

Effective 19 August 2021 Mr Bednall is a member of the Audit Committee, the People & Remuneration Committee and the Governance & Nomination Committee, and effective 9 November 2023 Mr Bednall is a member of the Risk and Sustainability Committee.

MS GISELLE M. COLLINS

B. Ec, CA , GAICD

Independent Non-Executive Director

Appointed 19 Aug 2021

Experience and expertise
Ms Collins has broad executive and director experience across finance, treasury and property disciplines.

Ms Collins' executive positions included General Manager Property, Treasury and Tourism of NRMA, Chief Executive Officer, Property and General Manager Finance with the Hannan Group, and Senior Manager, Audit Services with KPMG Switzerland. Ms Collins is a former non-executive director and Chairman of the following companies: Aon Superannuation (2016 – 2017), The Travelodge Hotel Group (2009 – 2013) and The Heart Research Institute Limited (2003 – 2011).

Current and other directorships in the last 3 years
Ms Collins is Chairman of Hotel Property Investments (ASX:HPI) since 2022, director since 2017 and recently appointed as Chairman of Pacific Smiles Limited (ASX:PSQ), director since 2023. Ms Collins is also a non executive director of Generation Development Group (ASX:GDG) since 2018 and Chairman of the responsibility entity (RE) for AMP Limited's managed investment schemes since 2021.

Ms Collins is a former Chairman for Indigenous Business Australia in the Darwin Hotel Pty Limited, non-executive director of Generation Life (2018 – 2021) and Peak Rare Earths Limited (ASX:PEK) (2021 – 2023).

Special responsibilities
Effective 19 August 2021 Ms Collins is a member of the Audit Committee and the Risk & Sustainability Committee. Effective 9 November 2023 Ms Collins is the Chairman of the Audit Committee and a member of the Governance & Nomination Committee.

MS ELIZABETH A. DONAGHEY

B.Sc., M.Sc.

Independent Non-Executive Director

Appointed 25 June 2018

Experience and expertise
Ms Donaghey brings over 30 years' experience in the energy sector including technical, commercial and executive roles in EnergyAustralia, Woodside Energy and BHP Petroleum.

Ms Donaghey's experience includes non-executive director roles at Imdex Ltd (an ASX-listed provider of drilling fluids and downhole instrumentation), St Barbara Ltd (a gold explorer and producer), and the Australian Renewable Energy Agency. She has performed extensive committee roles in these appointments, serving on audit and compliance, risk and audit, technical and regulatory, remuneration and health and safety committees.

Current and other directorships in the last 3 years
Ms Donaghey is currently a non-executive director of the Australian Energy Market Operator (AEMO) (since 2017) and a non-executive director of Ampol Limited (ASX: ALD) (since 2021).

Special responsibilities
Effective 19 August 2021 Ms Donaghey is a member of the Risk & Sustainability Committee, the People & Remuneration Committee and the Governance & Nomination Committee. Effective 23 June 2023 Ms Donaghey is the Chairman of the Risk & Sustainability Committee.

MR JEFFREY W. SCHNEIDER

B.Com

Independent Non-Executive Director

Appointed 12 Oct 2011

Experience and expertise
Mr Schneider has over 30 years of experience in senior management roles in the oil and gas industry, including 24 years with Woodside Energy. He has extensive corporate governance and board experience as both a non-executive director and chairman in resources companies.

Current and other directorships in the last 3 years
Mr Schneider does not currently hold any other directorships.

Special responsibilities
Effective 19 August 2021 Mr Schneider is Chairman of the People & Remuneration Committee. Effective 9 November 2023 Mr Schneider is also a member of the Audit Committee.

MS VICTORIA J. BINNS

B. Eng (Mining – Hons 1), Grad Dip SIA, FAusIMM, GAICD

Independent Non-Executive Director

Appointed 2 March 2020
Retired 9 Nov 2023

Experience and expertise
Ms Binns has over 35 years' experience in the global resources and financial services sectors, including more than 10 years in executive leadership roles at BHP and 15 years in financial services with Merrill Lynch Australia and Macquarie Equities. During her career at BHP, Ms Binns' roles included Vice President Minerals Marketing, leadership positions in the metals and coal marketing business, Vice President of Market Analysis and Economics and was a member of the first BHP Global Inclusion and Diversity Council.

Prior to joining BHP, Ms Binns held a number of board and senior management roles at Merrill Lynch Australia including Managing Director and Head of Australian Research, Head of Global Mining, Metals and Steel, and Head of Australian Mining Research. She was also co-founder and Chair of Women in Mining and Resources Singapore.

Current and other directorships in the last 3 years
Ms Binns is a non-executive director of Evolution Mining (ASX:EVN) (since 2020) and Sims Limited (ASX:SGM) (since 2021). She is also a non-executive director of the Carbon Market Institute and a member of the J.P. Morgan Australia & NZ Advisory Council.

Special responsibilities
Prior to her retirement, Ms Binns was the Chairman of the Audit Committee and was a member of the Risk & Sustainability Committee.

EXECUTIVE LEADERSHIP

MS JANE L. NORMAN

B.Sc., B.Eng. (Hons) PGDip, GAICD

Managing Director and CEO

Ms Norman's biography is shown in the Director's section of the report.

MR DANIEL YOUNG

B. Com (Hons), MBA (Hons), CA, CFA

Chief Financial Officer

Mr Young joined Cooper Energy in May 2022. Mr Young is an energy professional with over 28 years of experience in Australia, Asia and Europe. He joined Cooper Energy from Jadestone Energy plc where he held the role of Chief Financial Officer for over five years. He also held the role of Executive Director with Jadestone. Daniel played a key role in the management team, charged with the funding, growth and development of Jadestone. The compound annual share price growth rate averaged 25% over this period.

Prior to Jadestone, Mr Young was Head of APAC Consulting for Wood Mackenzie and earlier worked in J.P. Morgan's energy investment banking coverage/mergers & acquisitions group, in Europe and in Asia. During this time, he worked on a number of noteworthy transactions in the energy sector.

After completing his undergraduate studies, Daniel joined Deloitte where he qualified as a Chartered Accountant. Daniel holds a Bachelor of Commerce with Firsts in Accounting and Finance from the University of Western Australia and an MBA with Honours from the University of Chicago Booth School of Business.
He is also a CFA® charterholder.

MR EDDY GLAVAS

B. Acc. FCPA, MBA

Chief Commercial Officer

Mr Glavas joined Cooper Energy in August 2014 and has more than 25 years of experience in business development, finance, commercial, portfolio management and strategy, including 22 years in the oil and gas sector. Prior to joining Cooper Energy, he was employed by Santos as Manager Corporate Development with responsibility for managing multi-disciplinary teams tasked with mergers, acquisitions, partnerships and divestitures.

Prior roles within Santos included: Finance Manager WA and NT, where Mr Glavas was a member of the leadership team that managed a large asset portfolio; corporate roles in strategy and planning; and operational, commercial and finance roles for Santos' Cooper Basin assets.

MR CHAD WILSON

B. Sc. Chem. Eng. (Distinction), B. Sc. Zoology (Chemistry), PEng, MIEAust CPEng NER

Chief Operating Officer

Mr Wilson joined Cooper Energy in October 2023 and has over two decades of experience in project development, production operations and business transformation.

He embarked on his professional journey as a Process Engineer at a prominent Canadian mining firm. He later joined Talisman Energy, where he held various roles in engineering, development, and, finally, an operational management role comprising five operating areas, six sweet gas plants and one of Alberta's major sour gas processing plants.

Subsequently, he joined Santos in Australia, where Chad was appointed Chief Production Engineer and later Vice President of Cooper Basin. He was instrumental in the transformation of the Cooper Basin asset through 2015-16, ensuring the asset was sustainably profitable in the low oil price environment. After heading up development and operations of the Cooper Basin for a further 4 years, he became Vice President, Energy Solutions, where he oversaw the development of the Moomba Carbon Capture and Storage Project and emissions reduction strategy and execution across Santos's portfolio. Chad has a proven track record of enhancing safety, production, and profitability through applying lean systems thinking.

He holds a Bachelor of Science in Chemical Engineering and a Bachelor of Science in Zoology/Chemistry from the University of Alberta, Canada.

MR NATHAN CHILDS

B. Chem. Eng. (Hons)

Chief Corporate Services Officer

Mr Childs has over 25 years of experience in the gas and oil industry, having held line, technical, engineering and executive management roles.

Before joining Cooper Energy in October 2019 as Head of Engineering and Planning, he was Santos's Vice President of Production Mid stream. He worked through several roles at Santos across plant and process operations; engineering; production optimisation; asset management; commercial business development; integrity, and reliability.

While working for Santos, Nathan made several strategic changes, including lowering operating costs, improving asset performance, increasing production, delivering $50 million of transformation initiatives to improve free cash flow and implementing Operations Discipline.

Nathan began his career with Rio Tinto in research and technology development. He later worked at ExxonMobil's refining and supply business after graduating with first-class honours from Adelaide University with a Bachelor of Engineering–Chemical.

MS YING LUO

B. Eng. (Hons), B. Sc. (Hons), MBA, Grad Cert.

Chief Advisor & General Manager Strategy

Ms Luo has almost 15 years of experience working in the energy sector in onshore gas, LNG and hydrogen.

She began her career as a Graduate Mechanical Engineer with Santos. She progressed through several roles over the following decade including Production Engineer, and Operations Engineer where she implemented solutions to design and operability issues identified during the commissioning and start-up of the GLNG Project upstream wells and facilities.

Ying also worked in the Corporate Strategy and Planning team, providing oil, LNG and domestic gas market analysis, supporting the development of Santos' 10-year strategic plan. Her last four years with Santos were as the Project and Strategy Lead for the Energy Solutions division. Ying developed, implemented, and maintained the Energy Solutions strategy and led a portfolio of emissions reduction, renewable integration and hydrogen projects. Most recently she worked as the Senior Adviser, Hydrogen Development for the Australian Gas Infrastructure Group where she led the development of Australia's largest renewable hydrogen production and blending project in Albury-Wodonga, Victoria.

Ying has a Bachelor of Mechanical Engineering with First Class Honours; Bachelor of Science (Mathematics, Computer Science) with First Class Honours; Graduate Certificate in Energy and Resources Policy and Practice and an MBA. She was awarded the Sir John Monash Scholarship for Excellence at Monash University and the Exceptional Young Women in Resources from the South Australian Chamber of Mines and Energy.

MS NICOLE ORTIGOSA

BA LLB (Hons), Grad Dip Legal Practice

Company Secretary & General Counsel

Ms Ortigosa has over 15 years' experience as a corporate and commercial lawyer, specialising in the energy and resources sector. Prior to joining Cooper Energy she worked for top tier law firms across Australia, including Clifford Chance and Minter Ellison. Nicole's experience covers all legal, corporate, and commercial aspects of the business, including joint ventures, gas sales, infrastructure, environment, regulatory, procurement, mergers and acquisitions, corporate governance and compliance.

Nicole started at Cooper Energy in 2017 and prior to becoming General Counsel & Company Secretary was the Legal Manager. Amongst other matters, she has advised the company on the development of the Sole gas field, the acquisition of the Athena Gas Plant and associated infrastructure and the acquisition of the Orbost Gas Processing Plant and associated onshore and offshore pipeline infrastructure.

She holds a Bachelor of Laws with Honours from the University of Adelaide, and a Graduate Diploma in Legal Practice from the Law Society of South Australia.

MR ANDREW THOMAS

B. Sc. (Hons)

Chief Exploration & Subsurface Officer

Ceased as Executive KMP on 30 June 2024

Mr Thomas is a successful and experienced geoscientist who has been involved with Australian and international gas and oil exploration and development projects for over 30 years. He has experience in a wide range of onshore and offshore basins in Australia, Asia and Africa.

Prior to joining Cooper Energy, Mr Thomas was employed by Newfield Exploration in the roles of Southeast Asia New Ventures Manager and Exploration Manager for offshore Sarawak and was a key person in the team that successfully negotiated Newfield's entry into Malaysia in 2004. Through the efforts of the teams he led, Newfield built a substantial portfolio of permits in Malaysia and made several significant oil and gas discoveries before being divested to SapuraKencana in 2014.

Mr Thomas's previous employers include Santos Limited, Gulf Canada and Geoscience Australia. He is a member of the American Association of Petroleum Geologists and a member of the Society of Petroleum Engineers.

Mr. Thomas leaves Cooper Energy on 30 September 2024, after 12 years of dedicated service. Mr Thomas ceased as Executive KMP on 30 June 2024.

KEY PERFORMANCE INDICATORS

		FY20	FY21	FY22	FY23	FY24
OPERATIONAL						
Production	PJe	9.2	16.1	20.3	21.8	22.7
2P Proved and Probable Reserves	MMboe	49.9	47.1	39.5	36.3	33.0
Wells drilled	#	18	1	2	2	4
Exploration wells spudded	#	4	-	2	-	4
1P Reserves replacement ratio[1]	%	-65%	17%	-65%	24%	-1%
FINANCIAL						
Sales revenue	$ million	78.1	131.7	205.4	196.9	219.0
Other income	$ million	19.8	7.2	-	-	3.4
Underlying EBITDAX	$ million	29.6	30.0	80.7	109.3	127.5
Net profit / (loss) before tax	$ million	-110.0	-33.5	-22.7	-104.7	-125.1
Underlying profit / (loss) after tax	$ million	-6.6	-25.9	14.4	-5.6	1.4
Cash and cash equivalents	$ million	131.6	91.3	247.0	77.1	14.3
Underlying cash from operations	$ million	30.8	24.6	80.6	95.8	114.8
Working capital	$ million	90.4	30.3	190.3	-121.8	-52.9
Accumulated profit	$ million	-136.0	-166.0	-177.5	-214.3	-328.4
Franking credits	$ million	42.9	42.9	42.9	42.9	42.9
Total Equity	$ million	351.1	325.8	498.4	528.5	417.6
Earnings per share	cents	-5.3	-1.8	-0.6	-2.3	-4.3
Return on shareholder funds	%	-21.9%	-8.9%	-2.6%	-11.8%	-24.1%
Total shareholder return	%	-30.6%	-30.7%	-5.8%	-38.8%	+50.0%
CAPITAL AS AT 30 JUNE 2024						
Share price	$	0.375	0.260	0.245	0.15	0.225
Issued shares	#	1,621.6	1,631.0	2,379.8	2,631.5	2,640.0
Market capitalisation	$ million	608.1	424.1	583.1	394.7	594.0

[1]The annual reserve replacement ratio is calculated based on the 1P Reserve revisions (excluding production) divided by Financial Year production

FINANCIAL REPORT

30 June 2024

COOPER ENERGY LIMITED
and its controlled entities.

ABN 93 096 170 295

CONTENTS

OPERATING AND FINANCIAL REVIEW

OPERATIONS

Cooper Energy Limited and its controlled entities ("Cooper Energy", or the "Company", or the "Group") generates revenue from the production of gas and condensate in the Otway and Gippsland Basins, and from the production of oil in the Cooper Basin.

The Company's current operations and interests include:

- offshore gas and gas liquids production in the Gippsland Basin, Victoria, from the Sole gas field;
- offshore gas and gas liquids production in the Otway Basin, Victoria, from the Casino, Henry and Netherby gas fields;
- onshore oil production in the western flank of the Cooper Basin, South Australia;
- the Orbost Gas Processing Plant ("OGPP") onshore Gippsland Basin, Victoria;
- the Athena Gas Plant ("AGP") onshore Otway Basin, Victoria;
- the Annie gas discovery in the offshore Otway Basin and the Dombey gas discovery in the onshore Otway Basin;
- the undeveloped Manta and Gummy gas and liquids fields in the Gippsland Basin; and
- exploration prospectivity in the onshore and offshore Otway, offshore Gippsland and Cooper Basins.

The Company is the operator of all its offshore activities, as well as the OGPP and AGP, and non-operator of all its onshore activities.

Workforce
At 30 June 2024, the Company had 126.1 full time equivalent ("FTE") employees and 13.4 FTE contractors, compared with 128.9 FTE employees and 24.4 FTE contractors at 30 June 2023. This 9% reduction in both employee and contractor numbers in FY24 is largely tied to the completion of the BMG wells decommissioning programme.

Contractors are engaged via third parties in South Australia, Western Australia and Victoria, and numbers fluctuated predominantly driven by the requirements of the BMG wells decommissioning project. As of 30 June 2024, all contractors engaged by Cooper Energy were contracted via third party providers.

Health, safety and environment
For the twelve months to 30 June 2024 the Group recorded zero fatalities, one lost time injury, one restricted work case and one medical treatment injury.

The lost time injury occurred at the OGPP in November 2023; a Cooper Energy employee suffered a finger injury requiring surgery and resulting in a lost time period of 3 days.

The restricted work case occurred at AGP in March 2024, where a contractor suffered discomfort in the lower back requiring restricted work duties to be assigned.

The medical treatment case occurred on the Helix Q7000 semi-submersible well intervention vessel during the BMG wells decommissioning project in January 2024, where a contractor suffered a lacerated ear requiring stitches.

The total recordable injury frequency rate ("TRIFR") was 4.35 per million hours worked in the 12 months to 30 June 2024, well below the industry benchmark of 5.86[1] injuries per million hours worked. The TRIFR declined from the 4.38 per million hours worked recorded in the previous 12 months to 30 June 2023, which was also below the industry benchmark of 5.68[1].

There were no reportable[2] or notifiable[3] environmental incidents during the period.

Sustainability
A mixture of Australian Carbon Credit Units and Climate Active eligible international credits were retired at the end of H1 FY24 and H2 FY24 to offset the Company's estimated FY24 scope 1, scope 2 and relevant scope 3 emissions[4].

Carbon credit retirements in H2 FY24 were based on an estimate of emissions and will be trued-up once FY24 emissions data is finalised.

[1] NOPSEMA industry rolling 12-month TRIFR for 30 June 2023 and 30 June 2024
[2] As defined by *Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009*
[3] As defined by the Victorian *Environment Protection Act 2017*
[4] See page 15 of Cooper Energy 2023 Sustainability Report for scope definitions

For the year ended 30 June 2024

OPERATING AND FINANCIAL REVIEW

RESERVES AND CONTINGENT RESOURCES

Proved and Probable Reserves (2P) at 30 June 2024 are assessed to be 33.0 MMboe, compared with 36.3 MMboe at 30 June 2023.

Changes to 2P Reserves for FY24 include production of -3.7 MMboe and 2P Reserves revisions of +0.4 MMboe. Contingent Resources (2C) at 30 June 2024 are assessed to be 48.4 MMboe compared with 48.4 MMboe at 30 June 2023.

Details of Reserves and Contingent Resources and the movement from the previous year are available in the ASX announcement titled 'Reserves and Contingent Resources at 30 June 2024', released on 23 August 2024.

	Proved and Probable Reserves (2P)			Contingent Resources (2C)		
As at 30 June 2024[1]	**Gas PJ**	**Oil & condensate MMbbl**	**Total MMboe**	**Gas PJ**	**Oil & condensate MMbbl**	**Total MMboe**
Gippsland Basin	178.1	0.0	29.1	198.9	4.9	37.4
Otway Basin	18.0	0.0	3.0	64.7	0.1	10.7
Cooper Basin	0.0	0.9	0.9	0.0	0.3	0.3
Total Cooper Energy	**196.1**	**0.9**	**33.0**	**263.6**	**5.3**	**48.4**

[1] *As announced on 23 August 2024. Totals may not reflect arithmetic addition due to rounding. The method of aggregation is by arithmetic sum by category.*

Production[5]
Gas and oil production for FY24 was 22.7 PJ-equivalent ("PJe"), or 62.1 TJ-equivalent per day, 4.2% higher than the prior year, mainly due to increased gas production from Sole with the improved performance at OGPP.

Total gas production of 21.9 PJ, or 59.9 TJ/d, was 4.1% higher than the prior year. In the Gippsland Basin, increased Sole production and improved OGPP performance resulted in a 5.5% increase in gas production to 18.1 PJ, or 49.5 TJ/d. In the Otway Basin, natural field decline at CHN contributed to a 2.0% decline in gas production to 3.8 PJ, or 10.4 TJ/d (both net to Cooper Energy's 50% share).

Oil and condensate production was 131.0 kbbl, or 358 bbls/d (net to Cooper Energy's 25% share), 9.1% higher than the prior year due to the production uplift from three new wells in PRLs 85-104 (formerly PEL 92) in the Cooper Basin.

Production by product and basin is summarised in the following tables.

PRODUCTION BY PRODUCT		FY24	FY23	Change
Sales gas	PJ	21.9	21.1	4.1%
Oil and condensate[1]	kbbl	131.0	120.1	9.1%
Total production	**PJe**	**22.7**	**21.8**	**4.2%**

PRODUCTION BY BASIN		FY24	FY23	Change
Gippsland Basin				
Sole: sales gas	PJ	18.1	17.2	5.5%
Otway Basin				
Casino Henry: sales gas	PJ	3.8	3.9	(2.0%)
Casino Henry: condensate	kbbl	3.6	3.6	1.8%
Cooper Basin				
Oil[1]	kbbl	127.4	116.6	9.2%
Total production	**PJe**	**22.7**	**21.8**	**4.2%**

[1] *FY23 oil production figures may vary compared to previously reported data as a result of production allocation reconciliations. Percentages may not reflect arithmetic calculation due to rounding*

[5] Totals may not reflect arithmetic addition due to rounding

OPERATING AND FINANCIAL REVIEW

Orbost Gas Processing Plant
OGPP delivered an average gas processing rate of 49.5 TJ/d during FY24 (FY23: 47.1 TJ/d).
Production rates increased in H2 FY24 versus H1 FY24, largely due to the implementation of Orbost Improvement Project initiatives. Multiple records for Sole/OGPP production were set during Q3 FY24 including a record daily rate of 67.3 TJ/d, a 30-day average of 58.2 TJ/d, a 60-day average of 55.8 TJ/d and a 90-day average of 54.1 TJ/d.

However overall plant performance was below expectations for large periods of FY24, particularly during H1 FY24, with continued foaming and fouling issues in the sulphur absorber units constraining production rates and requiring absorber downtime for cleaning. Some of these issues arose from unsuccessful trials during the Orbost Improvement Project, with learnings applied to improve system stability.

Production was also impacted by short-term issues, such as unplanned generator maintenance in March 2024 and pipeline restrictions in June 2024, which have since been resolved.

The Sole gas field continues to perform in line with expectations.

Orbost Improvement Project
Numerous initiatives were implemented over FY24, focused on minimising foaming and fouling in the absorbers, increasing the time between absorber cleans and reducing the duration of cleans. Worksteams undertaken included:

- reinstatement of the polisher unit;
- installation of heat tracing and insulation around the polisher unit;
- installation of an alternative spray distributor configuration in the absorber beds;
- installation of a mist eliminator in one absorber;
- optimisation of the anti-foam agent pumps;
- trials of alternative packing material in the absorbers; and
- trials of absorber clean-in-place.

The polisher unit had a significant positive impact on production during the year. In late December 2023, a new type of polisher unit media was loaded and achieved a record life of nearly five months, four times longer than the previous record.

With the support of the polisher unit and other improvement initiatives, a record absorber runtime of 6 weeks between cleans was achieved over June - July 2024, compared to the previous typical absorber runtime of 2 - 3 weeks.

Work continues on identifying the root cause of the sulphur foaming and fouling issues in the sulphur absorber units. While this work is ongoing, the success of improvement programme initiatives to date has allowed the OGPP to operate more consistently and at higher rates.

Further Orbost Improvement Project initiatives are being progressed to improve the reliability of the OGPP and maximise production rates. With recent 30 day, 60 day, and 90 day production records, a decision has been made no longer to progress with the option to install a third absorber bed.

Athena Gas Plant
The AGP achieved an average gas processing rate of 10.4 TJ/d during FY24 (FY23: 10.7 TJ/d), both net to Cooper Energy's 50% share. Notable improvements in plant reliability were offset by natural decline in the CHN gas fields.

Low inlet pressure operations were successfully implemented in the beginning of 2024, resulting in a production uplift of approximately 1 TJ/d on average. Well cycling operations continued to be implemented throughout the year to optimise production from the CHN fields.

Production in Q3 FY24 was impacted by a planned maintenance shutdown and additional unplanned compressor maintenance.

During Q4 FY24 AGP demonstrated stable operation with zero reliability loss over the two months of May and June.

COMMERCIAL

Extended gas sales arrangements with key customers
On 6 November 2023, the Company signed an agreement with EnergyAustralia to extend the supply term under their existing Sole gas sales agreement ("GSA"). Under the amended agreement, the Company will supply five petajoules of natural gas annually, for three years, from January 2026. The contract is priced reflective of current market conditions for term contracts[6].

During December 2023, the Company completed a price review on a one petajoule per annum GSA. Cooper Energy achieved a favourable outcome, with the revised base contract price effective 1 January 2024 increasing by the maximum extent possible under the GSA.

Bairnsdale Power Station gas sales agreement
On 3 June 2024, the Company entered into an agreement with Alinta Energy to supply as-available gas to the Bairnsdale Power Station. The Bairnsdale Power Station is a 94 MW open cycle gas peaker, located approximately 100kms from the Orbost Gas Plant. Gas will be supplied during times of elevated electricity demand. The agreement highlights the growing opportunity for Cooper Energy to provide shaped gas products, to support the reliability of the electricity system, amidst growing variable renewables.

Gas Market Code
During the period the Company maintained its deemed exemption to the price rules under the Gas Market Code, noted as a small supplier supplying the domestic market.

Physical gas portfolio management
During the period the Company entered into a revised suite of commercial arrangements with Jemena's Eastern Gas Pipeline. The arrangements deliver increased flexibility to manage production variability experienced at the Orbost Gas Plant and delivery obligations under the Company's gas sale agreements.

[6] As an indication of current market conditions, please see the ACCC Gas Inquiry December 2023, interim update on east coast gas market, page 87

OPERATING AND FINANCIAL REVIEW

DEVELOPMENT, EXPLORATION AND ABANDONMENT

Gippsland Basin
Cooper Energy is the operator and 100% interest holder for all its Gippsland Basin interests. As at 30 June 2024, these interests comprised:

a) VIC/L32, which contains the Sole gas field;
b) VIC/RL13, VIC/RL14 and VIC/RL15, which contain the Basker, Manta and Gummy (BMG) gas and liquids fields (these retention leases also hold legacy infrastructure associated with the BMG oil project);
c) VIC/RL16, which contains the shut-in Patricia-Baleen gas field and infrastructure which connects to the OGPP; and
d) exploration permits VIC/P72, VIC/P75 and VIC/P80.

BMG wells decommissioning
During FY24, Cooper Energy decommissioned the former Basker and Manta wells in the offshore Basker-Manta-Gummy (BMG) retention leases. The work was primarily undertaken by the Helix Q7000 semi-submersible well intervention vessel.

Following delayed completion of the Tui field abandonment, the vessel departed New Zealand in late November 2023. Equipment and fuel were loaded at Geelong Port and Corner Inlet, adjacent to the Barry Beach Marine Terminal in Victoria, prior to transiting to the offshore BMG location. Well decommissioning operations commenced in late December 2023.

The late arrival of the Helix Q7000 in Australia resulted in the Company incurring more than three months of holding costs for the remaining contractor spread on the BMG programme. This delayed start and additional time required for startup activities consumed the budgeted contingency.

On 22 January 2024, the Company revised its mid-case cost estimate for the BMG wells decommissioning to approximately A$240-280 million, including a reasonable contingency for further non-productive time and adverse weather.

The BMG wells decommissioning programme was completed in May. The Helix Q7000 vessel went off-hire and departed the BMG site on 28 May. The programme incurred more than 360,000 person-hours with no lost time injuries and no significant environmental incidents. The success of the wells decommissioning project highlights the Company's commitment to health, safety, and the environment, as well as its strong engineering capability.

The total cost of the BMG wells decommissioning programme is expected to be slightly less than A$270 million, with the final value subject to remaining invoice reconciliation. Decommissioning costs were funded from cash on hand, organic cash generation and the existing senior debt facility.

Cooper Energy continues to pursue its Victorian Supreme Court claim against PT Pertamina Hulu Energi ("Pertamina") for Pertamina's 10% share of the BMG decommissioning costs. These costs relate to decommissioning the seven wells and future removal of related BMG subsea infrastructure.

Pertamina, via an Australian subsidiary, participated in the BMG oil project during its production life. Cooper Energy's claim against Pertamina arises from Pertamina's obligations under the withdrawal and abandonment provisions of the BMG joint operating and production agreement. Pertamina has been ordered by the Court to file its defence in September 2024.

Gippsland Basin farm-out
In May 2024, Cooper Energy commenced a process to bring a partner into VIC/P80 and VIC/L13,14 & 15 (Cooper Energy 100%) for the next Gippsland gas exploration and development phase.

The opportunity covers 185 PJ[7] of 2C discovered resource and > 1.3 Tcf[8] of prospective resource. This brownfield project is expected to have a low cost to develop, a clear commercialisation pathway via existing infrastructure, and a relatively lower overall emissions profile compared to alternate sources, such as gas transported to Victoria from Queensland or imported LNG.

Gippsland Basin gas storage
In Q4 FY24 Cooper Energy commenced studying potential repurpose of the shut-in Patricia-Baleen field in VIC/RL16 (Cooper Energy 100%) for gas storage.

[7] Contingent Resources for Manta gas and liquids announced to ASX on 12 August 2019, Contingent Resources for Gummy gas and liquids announced to ASX on 25 August 2023, 100% share

[8] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and net share of each prospect, were announced to ASX on 15 May 2023 (Gummy Deep), 13 April 2022 (Wobbegong), and 4 May 2016 (Manta Deep and Chimaera East)

OPERATING AND FINANCIAL REVIEW

Cooper Energy tested the existing equipment, and the results of these tests are being integrated into the Company's assessment of gas storage potential.

Otway Basin (Offshore)
The Company's interests in the offshore Otway Basin as at 30 June 2024 comprised:

a) a 50% interest in and operatorship of production licences VIC/L24 and VIC/L30 containing the producing Casino, Henry and Netherby gas fields, with the remaining 50% interest held by Mitsui E&P Australia and its associated entities ("Mitsui");
b) a 50% interest in and operatorship of production licences VIC/L33 and VIC/L34 containing part of the Black Watch and Martha gas fields, with the remaining 50% interest in these production licences held by Mitsui;
c) a 50% interest in and operatorship of exploration permit VIC/P44 containing the undeveloped Annie gas discovery, with the remaining 50% interest held by Mitsui;
d) a 100% interest in and operatorship of exploration permit VIC/P76;
e) a 50% interest in and operatorship of AGP (onshore Victoria), which is jointly owned with Mitsui and processes gas from the Casino, Henry and Netherby gas fields; and
f) a 10% non-operated interest in production licence VIC/L22, which holds the shut-in Minerva gas field, with Woodside Energy the operator and 90% interest holder.

East Coast Supply Project
Cooper Energy made significant progress on the East Coast Supply Project ("ECSP"), formerly referred to as the Otway Phase 3 Development ("OP3D"), under which the Company intends to maximise the use of existing Otway Basin infrastructure to bring much-needed gas supply to Southeast Australia.

The ECSP developments can be connected to Cooper Energy's existing gas processing infrastructure at the AGP, which has ~150 TJ/d of total capacity (100% gross), with first gas targeted for 2028.

In Q1 FY24, as part of a consortium agreement with three other operators, the Company secured the Transocean Equinox rig for its drilling campaign in the Otway Basin. The Transocean Equinox is estimated to arrive in the Otway Basin in circa mid-CY2025. Within the consortium agreement, Cooper Energy has committed to one firm well and has options to drill additional subsea development and/or exploration/appraisal wells.

Cooper Energy has evaluated a number of alternatives for the ECSP drilling and development campaign. The Company has focused on identifying the optimal campaign considering the size of prospects, the development's overall economic returns, scale of capital expenditure required and risk.

While Cooper Energy continues to evaluate ECSP alternatives, the Company is targeting a three-well programme. This includes developing 64.8 PJ[9] in gross 2C estimated resource (32.4 PJ net to Cooper Energy) through one well (Annie-2) and a two well exploration programme, with one planned geological sidetrack, targeting 358 Bcf[10] (179 Bcf net to Cooper Energy) of gross mean unrisked prospective resource potential.

Discussions with Mitsui, Cooper Energy's 50% joint venture partner in the Otway Basin, regarding the ECSP, are ongoing.

Cooper Energy expects to sanction the ECSP during FY25, at which time it will confirm the identity, number and timing of wells drilled as part of the programme. The Transocean Equinox is expected to commence drilling the first firm well of its campaign for Cooper Energy in FY26.

The ECSP is expected to be funded from a range of sources including organic cash generation, the existing secured bank debt facility as well as the accordion debt facility of up to $120 million. Additionally, the Company continues to engage with several gas customers to support new domestic gas supply through a range of funding options, which could include prepayments.

Minerva decommissioning
Woodside Energy, the Operator of VIC/L22 (Cooper Energy share 10%), will commence decommissioning of the Minerva gas field in late 2024. The subsea facilities (pipelines, umbilicals, etc.) will be removed first, followed by the subsequent decommissioning of three of the four Minerva wells. The Transocean Equinox rig is estimated to arrive in the offshore Otway Basin region in circa mid-CY2025 and will commence the Minerva wells decommissioning shortly thereafter.

Otway Basin (Onshore)
The Company's interests in the onshore Otway Basin as at 30 June 2024 comprised:

a) a 30% interest in PEL 494, PRL 32 and PEL 680 in South Australia, with the remaining interests held by the operator, Beach Energy;
b) a 50% interest in PEP 168 in Victoria, with the remaining interest held by the operator, Beach Energy; and
c) a 75% interest in PEP 171 in Victoria, with the remainder held by operator Vintage Energy Limited.

[9] Indicative only, not guidance. Projects are preliminary in nature and not yet sanctioned. Annie 2C resource is included on a gross basis as part of the Otway Basin 2C number in the FY23 Reserves and Contingent Resources ASX released on the 23 August 2024. See also Contingent Resource announcement: Annie Gas Field", 24 February 2020.

[10] The Low (P90), Mid (P50), Mean and High (P10) prospective resource estimates, and the net share of each prospect, were announced to ASX on 9 February 2022.

OPERATING AND FINANCIAL REVIEW

Exploration
The PEL 494 Dombey 3D seismic survey was processed during H1 FY24 and interpreted during H2 FY24. Analysis to delineate the resource potential of the Dombey gas field and identify potential new exploration opportunities is ongoing and expected to be completed in Q1 FY25.

Reprocessing of existing 3D seismic surveys within PEP 168 was conducted in H1 FY24, with several legacy 3D seismic datasets across PEP 168 reprocessed into one survey. Interpretation of this reprocessed seismic data was undertaken during the H2 FY24 and is ongoing to mature drilling prospects in the permit.

Cooper Basin
The Company's interests in the Cooper Basin as at 30 June 2024 comprised a 25% interest in PRLs 85-104 (formerly PEL 92), with the remaining interests held by the operator, Beach Energy.

Exploration and development
Cooper Energy took part in a four well exploration drilling campaign in PRLs 85-104 (formerly PEL 92) in the first half of FY24.

The first exploration well, Marion 1, was drilled in September 2023 and was plugged and abandoned after failing to encounter hydrocarbons in the primary Namur Reservoir.

Bangalee South 1, located 630 metres southeast of Bangalee 1, was drilled in October 2023 and intersected 2.9 metres of net oil pay in the Namur reservoir and 4.3 metres of net oil pay in the Birkhead reservoir. The well was cased and suspended as a future oil producer. The Birkhead zone was brought online in December 2023, with initial production above 350 bbls/d.

In October 2023, Wooley Rock 1 intersected 1.2 metres of net oil pay and was plugged and abandoned as a non-commercial discovery. Chadinga 1 was drilled in December 2023, approximately three kilometres northwest of the Wooley Rock discovery and was plugged and abandoned, having failed to encounter hydrocarbons.

TRANSFORMATION PROGRAMME

One of the Company's key priorities for FY24 was the execution of cost-out initiatives under the transformation programme, outlined during the FY23 full year results in August 2023.

The transformation programme is all encompassing, targeting savings and efficiency across the entire business.

To date, approximately A$10.5 million in net savings has been realised, with over 100 initiatives identified across the business. Around 85% of the identified initiatives were completed or actioned by the end of FY24, with the full effect of cost savings and benefits realised into FY25 and beyond.

Significant savings in production costs were achieved across the business, in particular at OGPP. A large part of the savings related to cleaning of the absorber beds, including renegotiating long standing contracts with third party contractors, as well as reducing the time and frequency of absorber cleans. Successful implementation of the in-situ absorber cleans has the potential to deliver meaningful further savings.

An additional focus area at OGPP was to reduce costs arising from the removal and disposal of solid sulphur and process liquids related to the treatment of gas. The Company is investigating beneficial reuse opportunities for the solid sulphur that is produced as a by-product at OGPP and currently classified as a waste. If successful, and in conjunction with more efficient liquids disposal, the Company is targeting more than A$2.0 million per year additional saving from this initiative.

Within the Company's gas commercial activities, the company has removed A$0.4 million in costs related to physical gas portfolio management, through cost saving initiatives and renegotiation of key contracts.

To date, approximately A$4.6 million in annualised G&A net savings has been realised, relative to FY23, as a result of a freeze in general salary rises, reduction in the size of the Board, reduction in the number of KMP, office rationalisation, reduction in the use of advisory services, and reductions to travel and entertainment wherever possible. This savings number is net of A$2.2 million of restructuring costs and other FY24 non-recurring items, hence we expect to see a further significant reduction in reported G&A in FY25.

OTHER ACTIVITIES

Orbost sulphur trial
In April 2024 the Company agreed with Gippsland Agricultural Group to undertake a six-month trial to use sulphur by-product from OGPP as an alternative to commercially available fertiliser. A permit for the trial was granted by the Victorian Environmental Protection Agency and the trial is underway with preliminary results expected in October 2024.

If successful, the trial will pave the way for the sulphur by-product to be used in commercial agricultural applications on an ongoing basis, eliminating the cost of disposal and potentially generating revenue. This would both reduce costs for the business, while contributing to the circular economy and creating opportunities within the community in which we operate.

OPERATING AND FINANCIAL REVIEW

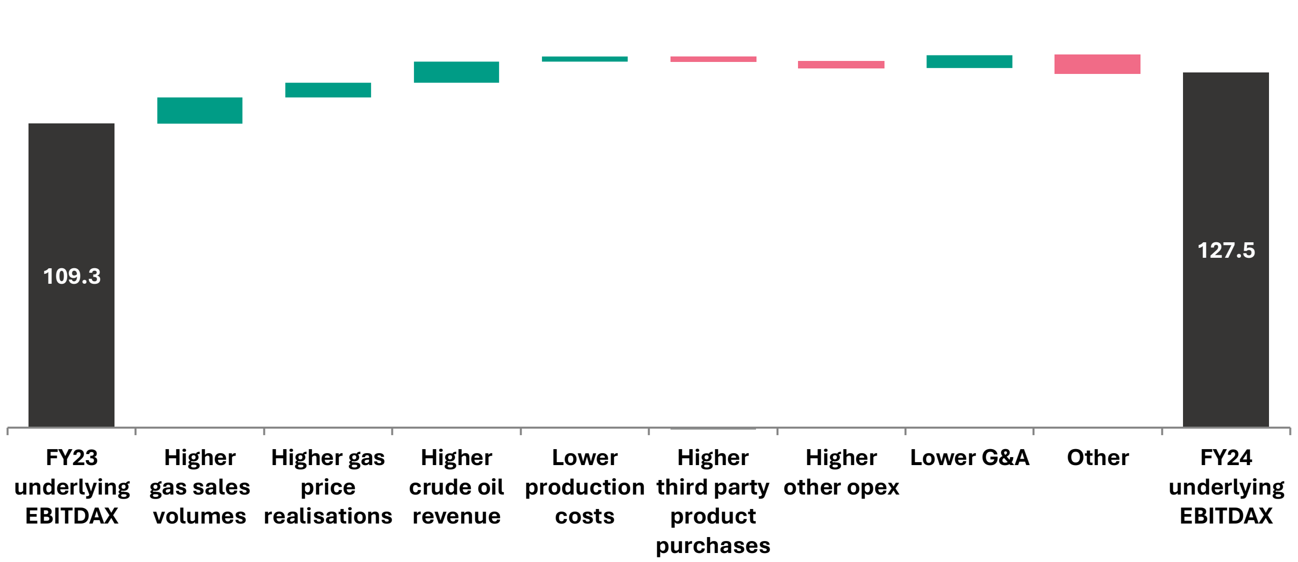
FINANCIAL PERFORMANCE

All numbers in tables in the Operating and Financial Review have been rounded and are expressed in Australian dollars, except where noted otherwise. Some total figures may differ insignificantly from totals obtained from the arithmetic addition of the rounded numbers presented.

In order to provide a more meaningful comparison of operating results between periods, the calculation of underlying EBITDAX and of underlying net profit/(loss) after tax includes adjustments for items which are considered unrelated to the Company's underlying operating performance.

Underlying EBITDAX and underlying net profit/(loss) after tax are not defined measures under International Financial Reporting Standards and are not audited. For that reason, reconciliations of underlying EBITDAX and of underlying net profit/(loss) after tax are included at the end of this review.

Cooper Energy recorded FY24 underlying EBITDAX of A$127.5 million, 16.7% higher than FY23. There are several drivers behind the change, which is summarised in the following chart.



The principal factors which contributed to the movement in underlying EBITDAX between the periods included:

- higher gas sales revenue of A$14.6 million attributed to higher sales volumes compared to the previous year (22.47 PJ in FY24, versus 21.41 PJ in FY23), together with higher realised gas prices across the portfolio (A$8.83/GJ in FY24, versus A$8.59/GJ in FY23);
- higher crude oil sales revenue of A$7.6 million, due to higher volumes of lifted oil (143.2 kbbls in FY24 versus 87.7 kbbls in FY23); and
- production expenses were lower by A$1.9 million in FY24. Production expenses reflect a full year of processing gas at OGPP with no toll payable to APA. Whilst costs have been incurred in addressing the sulphur depositional issues, savings have been realised from the transformation programme;
- third-party gas purchases and trading costs were higher by A$1.8 million in FY24 due to the timing of purchases to fulfill contracted sales (564.6 TJ gas purchased in FY24 versus 346.7 TJ in FY23);
- other opex was higher by A$2.3 million due to higher royalties and the production costs associated with oil sold from PEL 92 that was in inventory in FY23;
- lower G&A of A$4.6 million linked to savings realised from the transformation programme; and
- other items were higher by A$6.4 million primarily due to costs associated with care and maintenance work at Patricia-Baleen, as well as the impact of underlying adjustments.

OPERATING AND FINANCIAL REVIEW

Underlying profit after tax (exclusive of the items noted below) was A$1.4 million, compared with an underlying loss after tax of A$5.6 million in FY23. Factors driving the change, in addition to those listed above for underlying EBITDAX, included:

- higher net finance costs of A$6.5 million, mostly due to higher interest expense;
- higher exploration expenses of A$3.7 million, due to activity during the period; and
- lower tax benefit of A$1.5 million.

The Company's statutory loss after tax was A$114.1 million, which compares with a loss after tax of A$60.5 million recorded in FY23. The FY24 statutory loss included a number of significant items considered to fall outside underlying operating performance, which affected the result by a total of A$115.5 million.

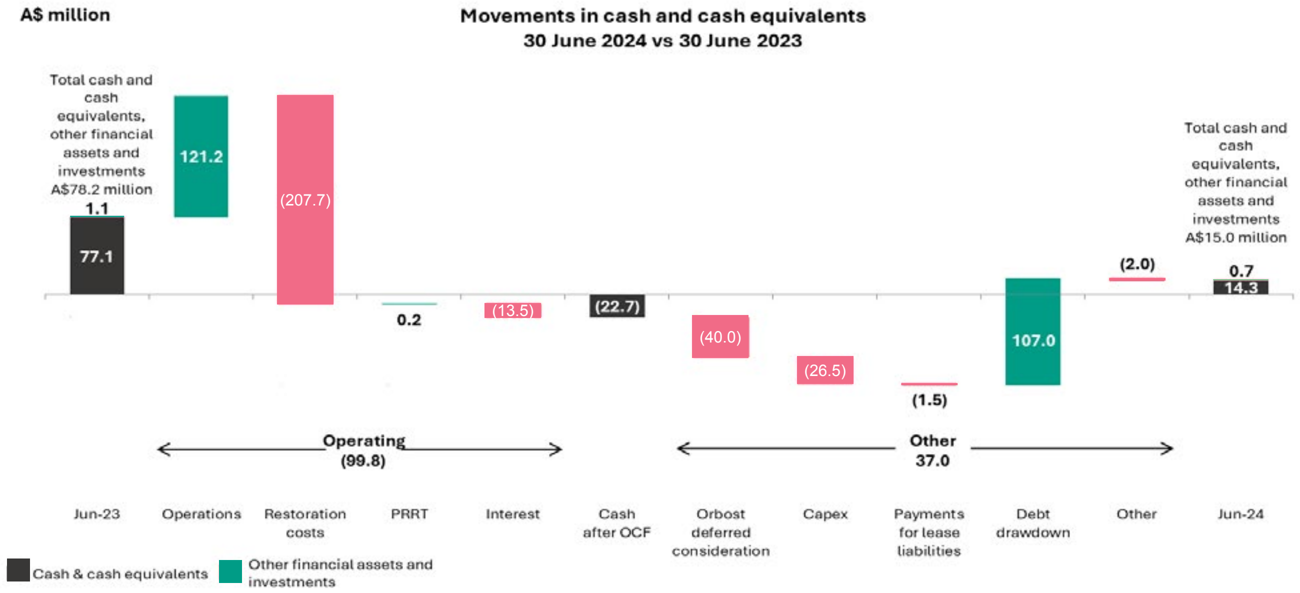
These items comprise:

- non-cash restoration expense of A$110.3 million resulting from a reassessment of the BMG, Patricia-Baleen, and Minerva Field decommissioning provisions;
- derecognition of the previously recognised deferred tax asset in respect of the Sole gas field decommissioning of A$33.3 million[11];
- business restructuring and transformation costs of A$3.4 million;
- FX hedging costs of A$1.5 million;
- a non-cash impairment expense of A$0.3 million in relation to one of the Group's exploration licences;
- OGPP acquisition and integration costs of A$0.1 million;
- other expense of A$1.8 million in respect of the National Oil & Gas Australia Pty Ltd Commonwealth Government levy; and
- tax impact of the above items of A$35.2 million.

Financial performance		FY24	FY23	Change	%
Production volume	PJe	22.74	21.81	0.93	4.2%
Sales volume	PJe	23.37	21.97	1.40	6.4%
Revenue	A$ million	219.0	196.9	22.1	11.2%
Gross profit	A$ million	51.7	32.5	19.2	59.1%
Underlying EBITDAX[1]	A$ million	127.5	109.3	18.3	16.7%
Operating cash flow	A$ million	(99.8)	62.8	(162.6)	N/M
Underlying loss before tax	A$ million	(7.7)	(16.0)	8.3	51.9%
Underlying profit/(loss) after tax	A$ million	1.4	(5.6)	7.0	N/M
Reported loss after tax	A$ million	(114.1)	(60.5)	(53.6)	(88.6%)
Cash, other financial assets and investments	A$ million	15.0	78.2	(63.2)	(80.8%)

[1] Earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment

Cash and cash equivalents decreased by A$62.8 million over the period, as summarised in the chart below.



[11] Based on the current 2P profile of the business, and before the additional production assumed from the ECSP and/or other future developments, taxable profits may not be generated at the time that Sole decommissioning is undertaken, hence there may be no taxable profits to be offset by the deduction for decommissioning costs.

OPERATING AND FINANCIAL REVIEW

Operating cash outflows for the period were A$99.8 million in FY24 versus cash inflows of A$62.8 million in FY23. The main line items for operating cashflow comprised:

- cash generated from operations of A$121.2 million (FY23: A$96.7 million). The major drivers of the increase are explained above in relation to underlying EBITDAX, while noting that changes in working capital are captured in cash from operations whereas EBITDAX is reported on an accruals basis;
- restoration costs of A$207.7 million (FY23: A$19.6 million), up mostly due to the wells abandonment activity at BMG in FY24;
- petroleum resource rent tax (PRRT) refunds of A$0.2 million (FY23: A$6.2 million payments), impacted by higher deductible expenditure in FY24; and
- net interest paid of A$13.5 million (FY23: A$8.1 million).

Excluding restoration spend and other non-recurring and non-underlying items, operating cash flow is A$114.8 million (FY23: A$95.8 million).
Financing, investing and other net cash inflows for the period were A$37.0 million (FY23: A$232.6 million net cash outflows) and primarily included:

- debt drawdown of A$107.0 million (FY23: nil);
- OGPP deferred acquisition payment of A$40.0 million (FY23 net acquisition cost of: A$237.0 million[12]);
- exploration, intangibles, development and property, plant and equipment costs of A$26.5 million, comprised of a number of different elements including order of the first subsea tree for the ESCP, drilling in the Cooper Basin and spend on the Orbost Improvement Project (FY23: A$38.6 million);
- nil proceeds from held for sale assets (FY23: A$0.7 million);
- repayment of lease liability of A$1.5 million (FY23: A$1.3 million); and
- other including foreign exchange revaluation A$2.1 million (FY23: A$1.0 million).

FINANCIAL POSITION

Financial Position		30 June 2024	30 Jun 2023 (Restated)	Change	%
Total assets	A$ million	1,223.2	1,365.0	(141.8)	(10.4%)
Total liabilities	A$ million	805.5	836.5	(31.0)	(3.7%)
Total equity	A$ million	417.6	528.5	(110.9)	(21.2%)
Net debt[1]	A$ million	(250.7)	(80.9)	(169.8)	209.9%

[1] Net debt is based on drawn debt of A$265.0 million (FY23: A$158.0 million). Total debt per the statement of financial position is A$253.1 million (FY23: A$143.9 million), which includes A$11.9 million (FY23: A$14.1 million) of prepaid financing costs.

TOTAL ASSETS

Total assets decreased by A$141.8 million from A$1,365.0 million at 30 June 2023 to A$1,223.2 million at 30 June 2024.

At 30 June 2024, the Company held cash and cash equivalents of A$14.3 million and investments of A$0.7 million.

Gas and oil assets decreased by A$60.7 million from A$535.8 million to A$475.1 million, mainly as a result of amortisation driven by production. Property, plant and equipment decreased by A$34.1 million from A$380.4 million at 30 June 2023 to A$346.3 million at 30 June 2024, mainly due to depreciation. Exploration and evaluation assets increased by A$9.2 million from A$184.6 million to A$193.8 million, due to PEL 92 exploration drilling and the order of the first subsea tree for the ECSP.

TOTAL LIABILITIES

Total liabilities decreased by A$31.0 million from A$836.5 million at 30 June 2023 to A$805.5 million at 30 June 2024.

The sum of current and non-current trade and other payables decreased by A$11.1 million year-on-year, from A$87.9 million at 30 June 2023 to A$76.8 million. Provisions decreased by A$117.0 million from A$583.6 million to A$466.6 million, primarily driven by the completion of BMG abandonment in FY24 and the reset of certain other provisions.

TOTAL EQUITY

Total equity decreased by A$110.9 million from A$528.5 million to A$417.6 million. In comparing equity at 30 June 2024 to 30 June 2023, the key movements were:

- higher contributed equity of A$2.2 million due to vesting of performance rights during the period;
- higher reserves of A$1.1 million due to share-based payments issued during the period offset by the transfer to issued capital for the vested rights; and
- higher accumulated losses of A$114.1 million due to the statutory loss for the period.

[12] OGPP upfront acquisition cost of A$210.0 million, plus other acquisition and financing costs of A$27.0 million

For the year ended 30 June 2024

OPERATING AND FINANCIAL REVIEW

STRATEGY AND OUTLOOK

On 4 June 2024, the Company set out its updated 10-year vision and strategy in an investor briefing presentation and webcast.

Cooper Energy remains focused on playing a crucial role in Australia's energy future, by building on its core business of producing domestic gas for Australian customers. Our strategy aligns with the Australian Government's Future Gas Strategy, which underscores the importance of gas in ensuring energy security, reliability and affordability, and supports the broader energy transition.

At Cooper Energy, we are committed to delivering gas to Australian consumers, including industrial manufacturers and major energy generators and retailers. Our strategy leverages our existing offshore and onshore infrastructure across Victoria, where the industry and community have coexisted for decades. This includes backfilling our facilities by developing new supply from existing basins that are close to market and opening our infrastructure for third-party access to maximise utilisation.

Today, in our target markets of Southeastern Australia, almost 40% of gas consumed is used by industrial customers to make products that are the backbone of Australia's economy. This includes customers in the construction, food processing and packaging sectors. As highlighted by the Australian Energy Market Operator[13], gas also remains critical to providing fast-start, reliable, dispatchable power to support the greater integration of variable renewables into the electricity market.

As the way gas is used evolves in the future, the shape of gas demand will change. We are investigating gas storage and peaking gas opportunities to deliver gas to our customers when they need it. Being able to supply gas during peak demand periods, particularly when flexible gas-powered generation is called upon, will enable us to capture additional value and margin. Gas storage could be provided through existing commercial arrangements that allow us to use 'line pack' in transmission pipelines, or using depleted reservoirs, such as our Patricia Baleen fields.

In FY25, our business priorities are strong organic cash generation, to de-risk our growth opportunities, and to deliver superior shareholder returns. To achieve this our objectives are to:

- Reduce production loss at Orbost to deliver low 60s TJ/d and group production >70 TJe/d by end-FY25;
- Increase realised gas prices through increased exposure to spot and peaking gas product opportunities;
- Drive further cost and emissions reductions through continuous improvement and efficiencies; and
- Progress the preferred drilling program to deliver the East Coast Supply Project and backfill AGP from 2028.

[13] See the 2024 Step Change scenario under AEMO's Gas Statement of Opportunities, March 2024, which "forecasts the potential for a long-term increase in gas-powered electricity generation consumption … due to an increasing need for firming support as coal generators continue to retire and electrical demand increases through electrification, particularly during winter seasons when solar output is low" (p.22)

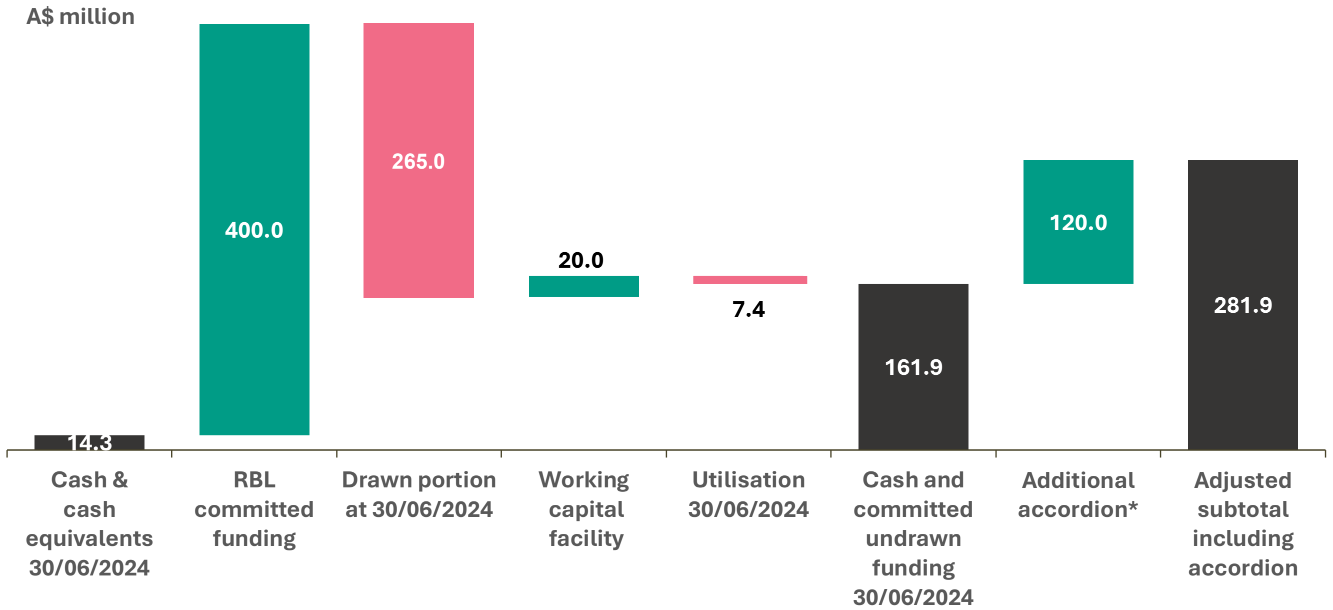
OPERATING AND FINANCIAL REVIEW

FUNDING AND CAPITAL MANAGEMENT

At 30 June 2024, the Company had cash reserves of A$14.3 million and drawn debt of A$265.0 million.

The Company has a reserves based loan facility with a group of banks, with a committed available limit of A$400.0 million as at 30 June 2024 (excluding an up to A$120.0 million accordion facility), to be used for general corporate purposes. Management plans to utilise the facility to part fund the planned ECSP in the Otway Basin.

The Company has additional liquidity of A$20.0 million through a working capital facility to be used for general business purposes, of which around A$7.4 million has been utilised in respect of bank guarantees as at 30 June 2024. The facility also includes an additional amount of up to A$120.0 million, under an accordion facility available, subject to certain terms and conditions. The Company's liquidity position as at 30 June 2024 is illustrated in the following chart:



* Subject to terms and conditions

Further information is detailed in the basis of preparation and accounting policies section of the Financial Statements.

The Company continues to assess accretive funding options as it pursues growth opportunities.

For the year ended 30 June 2024

OPERATING AND FINANCIAL REVIEW

RISK MANAGEMENT

The Company has an established risk management protocol that is applied at all organisational levels, and serves to identify and manage risk within the Company's risk appetite.

The Company's management system is being reviewed and revised to provide effective management of operational and business risks. The executive leadership team revises risk assessments and reviews risk management actions for corporate level risks on a regular basis.

The non-financial internal audit program supports the risk management program by reviewing the effectiveness of key risk controls and advising on improvements.

Corporate risk activities and internal audit outcomes are reported to and discussed with the Risk & Sustainability Committee of the Board. This Committee oversees the risk and non-financial audit programs and provides guidance.

RISK	DESCRIPTION
Production performance	The OGPP contributes around 80% of Cooper Energy group production. The plant has historically encountered sulphur removal and general reliability issues and it produced below its nameplate production capacity during FY24. Cooper Energy is progressing an improvement project targeting sulphur deposition and fouling in the absorbers, as well as general reliability improvements. There is a risk that the improvement project does not meet, or only partially meets, its objectives and that overall OGPP performance does not meet Cooper Energy's expectations in the future. Should OGPP production fall from FY24 levels of 49.5 TJ/d on average, Group revenue and operating cashflows will, all else held equal, likely decrease and impact Cooper Energy's strategic planning. Conversely, should the improvement project increase OGPP production towards its nameplate capacity, Group revenue and operating cashflows will, all else held equal, likely increase from FY24 levels. The Athena Gas Plant or AGP, formerly named the Minerva Gas plant, was built by BHP in 2009, and was repurposed and renamed the Athena Gas Plant by Cooper Energy in 2020. Characterised as a mature asset, there are inherent risks associated with aging equipment nearing end of life. Sales gas and raw gas compression reliability, aging fixed equipment, and end of life control systems for the offshore wells present ongoing production, revenue, and operating cashflow risks. Cooper Energy has developed and is progressing strategies and actions to mitigate and minimise these risks. Cooper Energy operates with a comprehensive range of operating and risk management plans and an enterprise-wide integrated management system to ensure safe and sustainable operations. To the extent that it is reasonable and possible to do so, Cooper Energy mitigates the risk of financial loss associated with operating events through insurance.
Health safety and environment	The nature of Cooper Energy's operations poses inherent risks to the health and safety of employees and contractors as well as posing a range of environmental risks. A major safety or environmental incident could jeopardise Cooper Energy's licence to operate, leading to delays, disruption and a potential interruption of the company's activities. Cooper Energy has a comprehensive approach to the management of health, safety and environmental risks. The company's management systems integrate technical and engineering requirements with management and mitigation of personal health and safety risks, process safety risks and environmental risks.
JV partnership alignment	Joint venture ownership and operation of assets is common in the gas and oil exploration and production industry. Joint ventures are structured to achieve a common goal to develop and operate an asset and are used to mitigate exploration and development risks including sharing of costs. The ability for Cooper Energy to execute growth activity in a joint venture ("JV") can be impacted by a change of circumstance and consequential divergent or misaligned strategy and appetite for capital investment by its JV partner. The joint operating agreement ("JOA") that covers the Company's JV in the offshore Otway contains sole risk and voting provisions in scenarios where JV parties have different or misaligned objectives.

OPERATING AND FINANCIAL REVIEW

Changes to restoration obligations/ provisions	Cooper Energy has certain restoration obligations with respect to its exploration and development licences, including subsea wells, production facilities and related infrastructure. These liabilities are derived from legislative and regulatory requirements, which are subject to change. Cooper Energy's balance sheet incorporates estimates for such decommissioning and abandonment activity, with those estimates included within provisions. Cooper Energy conducts a review of restoration provisions on a semi-annual basis. This includes a review of the assumptions included in the estimation, such as changes to the legislative and/or regulatory requirements for decommissioning and abandonment, future remaining reserves estimates, timing and costs and resultant production from the commercialisation of contingent resources, current prevailing market rates and costs to undertake decommissioning and abandonment activity, future inflation rates, and appropriate discount rates. Gas and oil reserves and estimates of contingent resources are expressions of judgement based on knowledge, experience and industry practice. Estimates may change and may change significantly, or become uncertain, when new information becomes available and/or there are material changes to circumstances which result in a change to plans. This may have a positive or negative effect on estimated restoration provisions. Changes to the estimate of restoration provisions are recognised in line with accounting standards. Restoration provisions are informed estimates, but there can be no assurance that the future actual costs associated with decommissioning and abandonment will not exceed the long-term provision quantum recognised to cover this activity.
Positive cash generation and access to capital	Cooper Energy undertakes significant capital expenditure to fund exploration, appraisal, development and restoration requirements. While Cooper Energy generates positive operating cashflow to reinvest into the business, it may also seek, from time to time, to access third-party capital to accelerate organic and/or inorganic growth options. Organic operating cashflow generation is dependent upon many variables, such as production rates including uptime, prevailing spot prices for uncontracted gas and global oil price benchmarks, operating costs, general and administration costs, taxation and foreign exchange rates. Spot gas prices are subject to fluctuations and are affected by numerous factors beyond the control of Cooper Energy. Cooper Energy monitors and analyses its gas and oil markets and seeks to reduce price risk where reasonable and practical. Gas price risk is assessed within the context of the Company's ongoing modelling of the Southeast Australian energy market and through its gas contracting strategy, which prioritises long term agreements and appropriate indexation and price review clauses. There can be no assurance that sufficient organic operating cashflow generation and/or access to incremental third-party capital will be available on acceptable terms, or at all. Lower organic operating cashflow generation and/or limitations on access to adequate incremental third-party capital could have a material adverse effect on the business, including the ability to commercialise discoveries and expand the Company's operations, long term results from operations, financial conditions and prospects, and compliance with covenants under the existing bank facility. If Cooper Energy accesses further funding under the existing debt facility, Cooper Energy's debt levels will increase. Consequently, there is a risk that Cooper Energy may be more exposed to risks associated with gearing and leverage. Failure to comply with the covenants of the debt facility could limit financial flexibility. It may enable the bank group to accelerate repayment of the Company's debt obligations. Lower organic operating cashflows, whether as a result of a decline in commodity prices or otherwise, may also give rise to changes in the assumptions incorporated into the estimation of fair market values used to test the carrying value of Cooper Energy's gas and oil assets.
Market intervention and legislative changes	Cooper Energy operates in a highly regulated environment and complies with the law. Federal or State Government intervention, legislative, policy or guideline changes can impact Cooper Energy's operations and share value. Changes, and uncertainty with respect to future legislative changes, can prolong compliance, delay approvals and escalate costs, impacting the company's financial position or expected financial returns. Cooper Energy engages with Federal and State governments and regulators on a regular basis to maintain open channels of communication.

OPERATING AND FINANCIAL REVIEW

Climate change & energy transition	Cooper Energy recognises its activities may be impacted by climate change and the energy transition. Risks are identified and managed in two broad categories: physical climate change risks relating to direct impacts on the Company's operations, and energy transition risks arising from the move to a net-zero energy system. A comprehensive range of risks and opportunities associated with climate change is incorporated into company policy, strategy and risk management processes. Cooper Energy has taken a proactive stance, since 2020, to voluntarily offset its Scope-1 (direct), Scope-2 (purchased electricity) and relevant Scope-3 emissions[14] (e.g. embedded energy and business travel), with a blend of Australian and international carbon credits. Cooper Energy also identifies and executes opportunities to reduce physical emissions from its operated assets, including opportunities to reduce flaring and fuel gas consumption, which also make more gas available to market. The Company's carbon neutral status[15] is certified by Climate Active, an initiative of the Australian Federal Government. For the avoidance of doubt, Cooper Energy does not offset downstream customer "Scope-3" emissions which arise primarily from processing, transmission, distribution and combustion of sold products. Cooper Energy is also investigating opportunities to invest in carbon credit origination projects, both in Australia and overseas. Investing in carbon credit origination projects aims to reduce the cost to access credible credits for our carbon neutral[16] certification. Our proactive approach to emissions reduction and voluntary offsets may also help to mitigate risks associated with climate activism. Cooper Energy is conscious of the risk of activism from some parts of the community and certain other stakeholders, aimed at delaying new natural gas projects, such as Cooper Energy's East Coast Supply Project (ECSP). Cooper Energy's project opportunities are in existing basins, leveraging existing infrastructure, helping to minimise the environmental footprint. The Australian Government's Future Gas Strategy, released in May 2024, highlights the principle of the need for new sources of gas supply, such as the ECSP, to meet demand during the economy-wide transition. On energy transition risk, the Company's domestic gas assets are resilient to the threat of demand loss from climate change. AEMO scenarios, including their central Step Change scenario, indicate that although gas demand may reduce slightly in Cooper Energy's target markets of Southeast Australia, gas supply is declining even faster, creating a significant opportunity for additional domestic gas supply. This underpins Cooper Energy's long-term strategy to grow its business and to increase market share. Gas is expected to play a significant role through the energy transition in two key areas. First, as a source for heating and industrial use by Australian manufacturers, where limited cost effective or practical alternatives are available, and second, to provide firming of variable renewable power generation as the electricity network continues to decarbonise. The Company's strategy continues to focus on conventional gas production, locally in Southeast Australia, close to market. The Company measures and publicly reports its emissions and emissions offsets to maintain its carbon neutral[14] position. These results, together with detail on climate change impacts, direct emissions reduction initiatives and its energy transition strategy, are described in Cooper Energy's annual Sustainability Report. Disclosures are aligned with the Taskforce on Climate related Financial Disclosures. See page 18 of the 2023 Sustainability Report for further information.

[14] Cooper Energy has been certified by Climate Active as a carbon neutral organisation for its Scope-1, Scope-2 and what Cooper Energy defines as its relevant Scope-3 emissions for FY20-23. Cooper Energy is in the process of seeking FY24 certification. See page 15 of Cooper Energy 2023 Sustainability Report for further information.
[15] Refer to footnote 14 above.
[16] Refer to footnote 14 above.

OPERATING AND FINANCIAL REVIEW

Cyber security	Cooper Energy's operations are, and will continue to be, reliant on various computer systems, data repositories and interfaces with networks and other systems. Failures or breaches of these systems (including by way of virus and hacking attacks) have the potential to materially and negatively impact Cooper Energy's operations. Cooper Energy has barriers, continuity plans and risk management systems in place, however there are inherent limits to such plans and systems. Further, Cooper Energy has no control over the cyber security plans and systems of third parties which may interface with Cooper Energy's operations, or upon whose services Cooper Energy's operations are reliant.
Access to skills and capabilities	Cooper Energy relies on the ability to attract and retain people with the right skills, behaviours and capability to deliver both its base business and its growth opportunities. It also relies on skills and expertise provided through industry service providers for both onshore and offshore operations. Failure to access such capability and services may constrain the achievement of business objectives. Cooper Energy has established employment conditions and practices, incentives and a workplace culture designed to attract and retain the skills and experience needed to deliver business objectives. The Company aims to appeal to a diverse group of individuals and ensure their inclusion in its 'one team' ethos. Metrics are in place to monitor employee engagement, and these are regularly reviewed by the executive leadership team and the Board. The company has well-established relationships with service providers regionally, domestically and globally. Cooper Energy collaborates with industry colleagues to partner in offshore campaigns, for example, as a means to share access to skills and experience. This includes the engagement of international providers with access to a global workforce. The company also has access to well-known and highly skilled contract personnel engaged to meet the various project requirements.

RECONCILIATIONS FOR NET LOSS TO UNDERLYING NET LOSS AND UNDERLYING EBITDAX

Reconciliation To Underlying EBITAX[1]		**FY24**	**FY23**	**Change**	**%**
Underlying profit/(loss)	**A$ million**	**1.4**	**(5.6)**	**7.0**	**125.1%**
Add back:					
Net finance costs	A$ million	15.0	8.5	6.5	76.5%
Accretion expense	A$ million	17.7	18.0	(0.3)	(1.7%)
Tax benefit	A$ million	(11.0)	(36.2)	25.2	69.6%
Tax adjustments to generate underlying profit/(loss)	A$ million	1.9	25.8	(23.9)	(92.6%)
Depreciation	A$ million	40.1	38.7	1.4	3.6%
Amortisation	A$ million	58.7	60.1	(1.4)	(2.3%)
Exploration and evaluation expense	A$ million	3.7	-	3.7	N/M
Underlying EBITDAX	**A$ million**	**127.5**	**109.3**	**18.2**	**16.7%**

Reconciliation to Underlying Loss		**FY24**	**FY23**	**Change**	**%**
Net loss after income tax	**A$ million**	**(114.1)**	**(60.5)**	**(53.6)**	**(88.6%)**
Adjusted for:					
OGPP reconfiguration and commissioning works	A$ million	-	0.4	(0.4)	N/M
OGPP acquisition and integration costs	A$ million	0.1	5.8	(5.7)	(98.2%)
Hedging costs	A$ million	1.5	-	1.5	N/M
APA toll normalisation	A$ million	-	2.9	(2.9)	N/M
Business restructuring and transformation	A$ million	3.4	2.7	0.7	25.9%
Restoration expense and associated costs	A$ million	110.3	49.1	61.2	124.6%
NOGA levy	A$ million	1.8	1.7	0.1	5.9%
Impairment	A$ million	0.3	26.1	(25.8)	(98.9%)
Derecognition of deferred income tax asset	A$ million	33.3	-	33.3	N/M
AASB 112 retrospective change	A$ million	-	(8.0)	8.0	N/M
Tax impact of adjustments to underlying loss	A$ million	(35.2)	(25.8)	(9.4)	(36.4%)
Underlying profit/(loss)	**A$ million**	**1.4**	**(5.6)**	**7.0**	**125.1%**

[1] Earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment.

DIRECTORS' STATUTORY REPORT

The Directors present their report together with the Consolidated Financial Report of the Group, being Cooper Energy Limited (the "parent entity" or "Cooper Energy" or "Company") and its controlled entities, for the financial year ended 30 June 2024, and the Independent Auditor's Report thereon.

1. DIRECTORS

The Directors of the parent entity at any time during or since the end of the financial year are:

MR JOHN C. CONDE AO
B.Sc. B.E(Hons), MBA
Chairman
Independent
Non-Executive Director
Appointed 25 February 2013

Experience and expertise
Mr Conde has extensive experience in business and commerce and in chairing high profile business, arts and sporting organisations.

Previous positions include non-executive director of BHP Billiton (ASX:BHP), Chairman of Bupa Australia, Chairman of Pacific Power (the Electricity Commission of NSW), Chairman of the Sydney Symphony Orchestra, director of AFC Asian Cup, Chairman of Events NSW, President of the National Heart Foundation, Chairman of the Pymble Ladies' College Council and director of Dexus Property Group (ASX:DXS).

Current and other directorships in the last 3 years
Mr Conde is Chairman of The McGrath Foundation (since 2013 and director since 2012) and Chairman of Dexus Wholesale Property Fund (DWPF) (since 2020).

Mr Conde is a former President of the Commonwealth Remuneration Tribunal (2003 – 2023) and Deputy Chairman of Whitehaven Coal Limited (ASX:WHC) (2007 – 2022)

Special responsibilities
Mr Conde is Chairman of the Board of Directors. Effective 19 August 2021 he is also a member of the People & Remuneration Committee and is the Chairman of the Governance & Nomination Committee.

MS JANE L. NORMAN
B.Sc.,B.Eng.(Hons) PGDip
GAICD
Managing Director and CEO
Appointed 20 March 2023

Experience and expertise
Jane has worked and studied in Australia and the UK and brings 30 years of industry experience in the energy markets. She began her career with Shell International Exploration & Production as a Process Engineer in operations and then as a Commercial Advisor in The Hague, Aberdeen and London. Subsequently, in London, Jane held corporate finance and equity capital markets roles with Cazenove & Co (now JP Morgan Cazenove) and Goldman Sachs.

Jane returned to Australia to join Santos where she held senior commercial, corporate strategy and Executive Committee roles. She led major strategic initiatives at Santos and played a key role in Santos' growth strategy, in particular the merger with Oil Search.

During her time at Santos Jane helped drive the transformation of company performance, helping to establish the growth strategy focused on cash generation and shareholder returns and, more recently, the company's energy transition strategy. Jane holds a Bachelor of Science (Pure Mathematics and Chemistry) and Bachelor of Chemical Engineering (Hons) from the University of Sydney and a Graduate Diploma in Management and Economics of Natural Gas (Distinction) from the University of Oxford. Jane is a Graduate of the Australian Institute of Company Directors.

Current and other directorships in the last 3 years
Ms Norman is a director of the wholly owned subsidiaries of Cooper Energy Limited and is on the Board of the Australian Energy Producers (since 2023).

Special responsibilities
Ms Norman is Managing Director and CEO. She is responsible for the day-to-day leadership of Cooper Energy, and is the leader of the Executive Leadership Team.

DIRECTORS' STATUTORY REPORT

MR TIMOTHY G. BEDNALL
LLB (Hons)
Independent Non-Executive Director
Appointed 31 March 2020

Experience and expertise
Mr Bednall is a highly experienced and respected corporate lawyer and law firm manager. He is a partner of King & Wood Mallesons (KWM), where he specialises in mergers and acquisitions, capital markets and corporate governance, representing public company and government clients. Mr Bednall has advised clients in the oil and gas and energy sectors throughout his career.

Mr Bednall was the Chairman of the Australian partnership of KWM from January 2010 to December 2012, during which time the merger of King & Wood and Mallesons Stephen Jaques was negotiated and implemented. He was also Managing Partner of M&A and Tax for KWM Australia from 2013 to 2014, and Managing Partner of KWM Europe and Middle East from 2016 to 2017. He was General Counsel of Southcorp Limited (which became the core of Treasury Wine Estates Limited) from 2000 to 2001.

Current and other directorships in the last 3 years
Mr Bednall is a board member of the National Portrait Gallery Foundation (since 2018) and a director of Pooling Limited (since 2017).

Special responsibilities
Effective 19 August 2021 Mr Bednall is a member of the Audit Committee, the People & Remuneration Committee and the Governance & Nomination Committee, and effective 9 November 2023 Mr Bednall is a member of the Risk and Sustainability Committee.

MS GISELLE M. COLLINS
B. Ec, CA
GAICD
Independent
Non-Executive Director
Appointed 19 August 2021

Experience and expertise
Ms Collins has broad executive and director experience across finance, treasury and property disciplines.

Ms Collins' executive positions included General Manager Property, Treasury and Tourism of NRMA, Chief Executive Officer, Property and General Manager Finance with the Hannan Group, and Senior Manager, Audit Services with KPMG Switzerland. Ms Collins is a former non-executive director and Chairman of the following companies: Aon Superannuation (2016 – 2017), The Travelodge Hotel Group (2009 – 2013) and The Heart Research Institute Limited (2003 – 2011).

Current and other directorships in the last 3 years
Ms Collins is Chairman of Hotel Property Investments (ASX:HPI) since 2022, director since 2017 and recently appointed as Chairman of Pacific Smiles Limited (ASX:PSQ), director since 2023. Ms Collins is also a non executive director of Generation Development Group (ASX:GDG) since 2018 and Chairman of the responsibility entity (RE) for AMP Limited's managed investment schemes since 2021.

Ms Collins is a former Chairman for Indigenous Business Australia in the Darwin Hotel Pty Limited, non-executive director of Generation Life (2018 – 2021) and Peak Rare Earths Limited (ASX:PEK) (2021 – 2023).

Special responsibilities
Effective 19 August 2021 Ms Collins is a member of the Audit Committee and the Risk & Sustainability Committee. Effective 9 November 2023 Ms Collins is the Chairman of the Audit Committee and a member of the Governance & Nomination Committee.

DIRECTORS' STATUTORY REPORT

MS ELIZABETH A. DONAGHEY
B.Sc., M.Sc.
Independent
Non-Executive Director
Appointed 25 June 2018

Experience and expertise
Ms Donaghey brings over 30 years' experience in the energy sector including technical, commercial and executive roles in EnergyAustralia, Woodside Energy and BHP Petroleum.

Ms Donaghey's experience includes non-executive director roles at Imdex Ltd (an ASX-listed provider of drilling fluids and downhole instrumentation), St Barbara Ltd (a gold explorer and producer), and the Australian Renewable Energy Agency. She has performed extensive committee roles in these appointments, serving on audit and compliance, risk and audit, technical and regulatory, remuneration and health and safety committees.

Current and other directorships in the last 3 years
Ms Donaghey is currently a non-executive director of the Australian Energy Market Operator (AEMO) (since 2017) and a non-executive director of Ampol Limited (ASX: ALD) (since 2021).

Special responsibilities
Effective 19 August 2021 Ms Donaghey is a member of the Risk & Sustainability Committee, the People & Remuneration Committee and the Governance & Nomination Committee. Effective 23 June 2023 Ms Donaghey is the Chairman of the Risk & Sustainability Committee.

MR JEFFREY W. SCHNEIDER
B.Com
Independent Non-Executive Director
Appointed 12 October 2011

Experience and expertise
Mr Schneider has over 30 years of experience in senior management roles in the oil and gas industry, including 24 years with Woodside Energy. He has extensive corporate governance and board experience as both a non-executive director and chairman in resources companies.

Current and other directorships in the last 3 years
Mr Schneider does not currently hold any other directorships.

Special responsibilities
Effective 19 August 2021 Mr Schneider is Chairman of the People & Remuneration Committee. Effective 9 November 2023 Mr Schneider is also a member of the Audit Committee.

MS VICTORIA J. BINNS
B. Eng (Mining – Hons 1),
Grad Dip SIA, FAusIMM, GAICD
Independent
Non-Executive Director
Appointed 2 March 2020

Retired 9 November 2023

Experience and expertise
Ms Binns has over 35 years' experience in the global resources and financial services sectors, including more than 10 years in executive leadership roles at BHP and 15 years in financial services with Merrill Lynch Australia and Macquarie Equities. During her career at BHP, Ms Binns' roles included Vice President Minerals Marketing, leadership positions in the metals and coal marketing business, Vice President of Market Analysis and Economics and was a member of the first BHP Global Inclusion and Diversity Council.

Prior to joining BHP, Ms Binns held a number of board and senior management roles at Merrill Lynch Australia including Managing Director and Head of Australian Research, Head of Global Mining, Metals and Steel, and Head of Australian Mining Research. She was also co-founder and Chair of Women in Mining and Resources Singapore.

Current and other directorships in the last 3 years
Ms Binns is a non-executive director of Evolution Mining (ASX:EVN) (since 2020) and Sims Limited (ASX:SGM) (since 2021). She is also a non-executive director of the Carbon Market Institute and a member of the J.P. Morgan Australia & NZ Advisory Council.

Special responsibilities
Prior to her retirement, Ms Binns was the Chairman of the Audit Committee and was a member of the Risk & Sustainability Committee.

DIRECTORS' STATUTORY REPORT

2. COMPANY SECRETARY

Ms Nicole Ortigosa B.A., LLB (Hons), Grad Dip Legal Practice was appointed to the position of Company Secretary and General Counsel effective from 21 April 2023.

Nicole has over 16 years experience as a corporate and commercial lawyer, specialising in the energy and resources sector. Prior to joining Cooper Energy she worked for top tier law firms across Australia, including Clifford Chance and Minter Ellison. Nicole's experience covers all legal, corporate, and commercial aspects of the business, including joint ventures, gas sales, infrastructure, environment, regulatory, procurement, mergers and acquisitions, corporate governance and compliance.

Nicole started at Cooper Energy in 2017 and prior to becoming General Counsel & Company Secretary was the Legal Manager. Amongst other matters, she has advised the company on the development of the Sole gas field, the acquisition of AGP and associated infrastructure and the acquisition of OGPP and associated onshore and offshore pipeline infrastructure.

She holds a Bachelor of Laws with Honours from the University of Adelaide and a Graduate Diploma in Legal Practice from the Law Society of South Australia.

3. DIRECTORS' MEETINGS

The number of Directors' meetings (including meetings of committees of Directors) and number of meetings attended by each of the Directors during the financial year were:

Director	Board Meetings		Audit Committee Meetings		Risk & Sustainability Committee Meetings		People & Remuneration Committee Meetings		Governance & Nomination Committee Meetings	
	A	B	A	B	A	B	A	B	A	B
Mr J. Conde	7	7	-	-	-	-	4	4	1	1
Mr J. Norman	7	7	-	-	-	-	-	-	-	-
Mr T. Bednall	7	7	4	4	2	2	4	4	1	1
Ms E. Donaghey	7	7	-	-	4	4	4	4	1	1
Mr J. Schneider	7	7	2	2	-	-	4	4	1	1
Ms G. Collins	7	7	4	4	4	4	-	-	-	-
Ms V. Binns[1]	4	4	2	2	2	2	-	-	-	-

A = Number of meetings attended.

B = Number of meetings held during the time the Director held office, or was a member of the Committee, during the year.

[1] Ms Binns retired effective 9 November 2023

REMUNERATION REPORT

4. REMUNERATION REPORT (AUDITED)

Information about the remuneration of the Company's key management personnel for the financial year ended 30 June 2024 is set out in the Remuneration Report. The Remuneration Report forms part of the Directors' Report. It has been prepared in accordance with section 300A of the Corporations Act 2001 and has been audited as required by that Act.

REMUNERATION REPORT INTRODUCTION FROM THE CHAIRMAN OF THE PEOPLE & REMUNERATION COMMITTEE

Dear Shareholder,

The 2024 financial year (FY24) has seen notable improvement in the performance of the business and the achievement of a significant milestone with the completion of the BMG wells decommissioning project. This, together with the improving performance of the Orbost Gas Processing Plant (OGPP), provides a positive business setting which creates the opportunity for future growth. The company has a clear strategy supported by a refreshed Executive Leadership Team (ELT) established by Jane Norman, Managing Director & Chief Executive Officer since her commencement in March 2023.

This Remuneration Report reflects achievement levels in FY24 and the associated remuneration outcomes for the Key Management Personnel (KMP). The report documents the Company's remuneration framework and guiding principles and illustrates clearly the impact of the Company's performance on the remuneration outcomes. We will seek shareholders' support for the Remuneration Report at the 2024 Annual General Meeting.

The Board believes that the FY24 remuneration outcomes are appropriate, taking into account the Company's performance, changes in the business, cost of living and competition in the employment market for high quality staff.

Remuneration Report Context: 2024 Financial Year
The Company's performance in the 12 months to 30 June 2024 is reported in the Operating and Financial Review of the Financial Report. This performance and how it compared with the specific targets of the Company Scorecard provide the context of the Remuneration Report.

In FY24, the Company has been successful in maintaining its strong performance in Health and Safety at industry leading levels, together with no recordable environmental incidents. The financial targets (cash OPEX, net G&A and SIB Capex) were largely achieved. However, production levels are yet to reach target levels despite significant improvements and the commitment of the operations team under the new leadership of our Chief Operating Officer, Chad Wilson.

Our Projects & Growth scorecard dimension was predominately weighted to the successful completion of the BMG wells decommissioning project. The completion of this project demonstrated the strength of our engineering capability which was able to meet the many challenges of this large scale and complex task. It was also delivered without any significant safety or environmental incident. Whilst recognising the major efforts of the BMG project team, delays in the project and increased costs have meant that the minimum level for reward (above Threshold) was not achieved.

Full details of the scoring of the Company Scorecard for FY24 are captured in 4.6.2. The Board determined that a FY24 short-term incentive plan (STIP) payment be awarded that reflected a Company Scorecard result of 56.1%. STIP relating to individual performance will also be awarded to Executive KMP and Staff based on achievement against individual objectives. The FY24 STIP outcomes for the KMP are included in this report 4.6.3.

REMUNERATION DEVELOPMENTS

As foreshadowed in last years' report, the company's Executive KMP numbers have reduced. For FY25, there will be four Executive KMP roles namely the Managing Director and Chief Executive Officer, Chief Financial Officer, Chief Operating Officer and Chief Commercial Officer. In FY25 the Exploration and Subsurface function will come under the leadership of the Chief Operating Officer, Chad Wilson. Andrew Thomas, previously Chief Exploration and Subsurface Officer, leaves Cooper Energy after 12 years of dedicated service.

Other executive roles shown in this report continue to be part of the Cooper Energy Executive Leadership Team (ELT). The revised Executive KMP group better reflects those directly responsible for planning, directing and controlling the activities of Cooper Energy and the size of the business. The revised number of Executive KMP also better aligns with our industry peers.

Last year I also indicated that there would be a review of some aspects of our remuneration framework to ensure it is meeting its intended objectives of providing incentives to deliver superior performance to our shareholders, as well as attracting and retaining high calibre employees. As a result of this review, there have been some changes to the STIP and LTIP as it applies to the Executive KMP and broader ELT. These are described in 4.4.2 of this report. The changes are intended to strengthen the connection between the shareholder experience and remuneration outcomes of our executives.

REMUNERATION REPORT

REMUNERATION OUTCOMES

Fixed annual remuneration (FAR): planned increases to the Executive KMP FAR were communicated in last year's report. However, given the company's financial and business performance these increases did not proceed in FY24 (other than the statutory change to superannuation). This was true for the ELT and for Staff not covered by an enterprise agreement. The only exception was the small number of employees who took on additional responsibilities during FY24. This included the Chief Financial Officer. The decision not to proceed with general increases in FY24 was consistent with our cost containment objectives of FY24.

As a consequence, there has not been a general salary increase for ELT and Staff (excluding those covered by an enterprise agreement) since 1 July 2022. Statutory increases to the superannuation rate have been passed on to all employees. The Board determined that an increase will be applied to ELT and Staff effective 1 July 2024 including the increase in statutory superannuation. For the Executive KMP, these increases range from 1.8% to 4.42%. The overall increase for the whole of the ELT was 3.33%. Increases to base salaries are seen as comparable to our relevant peer companies and industry generally. The next general review of base salaries will be 1 October 2025.

Short term incentive plan (STIP): the FY24 STIP outcomes for the Executive KMP are included in this report in 4.6.3. These reflect the Company Scorecard result and achievement against FY24 individual objectives.

For FY25, a deferred equity component will be included in STIP for the ELT. To date, any STIP reward for the ELT has resulted in a cash payment. An equity opportunity has only existed in the LTIP. For the Managing Director & Chief Executive Officer (MD & CEO) and the Chief Operating Officer their existing maximum STIP opportunity will be adjusted to reduce the cash component and include the equity component. For example, in the case of the MD & CEO, the existing cash maximum opportunity of 125% of FAR, will become a maximum of 105% rewarded in cash and a maximum of 20% rewarded in equity (performance rights) with a deferral period of 12 months. Other ELT members will have their maximum STIP opportunity increased from 50% to 60% of FAR with the additional amount becoming an opportunity to earn performance rights (with a 12-month deferral period for vesting). This change is intended to strengthen the connection between the shareholder experience and remuneration outcomes of the ELT. Full details are described in 4.4.4.

Shareholders should note that if the FY25 STIP results in an eligible grant of performance rights (equity) for the MD & CEO, approval of shareholders will be sought at the 2025 Annual General Meeting (AGM).

Long term incentive plan (LTIP): our remuneration framework is also designed to reward superior performance over the long term and align executive performance with shareholder value. The Board has resolved to revise the structure of LTIP to include a second measurement resulting in two evenly weighted measures being relative total shareholder return (RTSR) and absolute total shareholder return (ATSR). Under the revised structure approved by the Board, grants will be solely in performance rights; share appreciation rights do not form part of the revised LTIP offer. The LTIP offer to the ELT in December 2023 (3-year plan) reflected this structure. The details of these measures are described in 4.4.5. For the MD & CEO, shareholders approved the revised LTIP structure at the 2023 AGM.

LTIP grants from December 2021 and 2022 will be tested in December 2024 and 2025 respectively. The structure of these plans remains as performance rights and share appreciation rights, with any vesting subject to actual performance against the nominated peer group (RTSR). There has been no vesting from the LTIP since December 2020, due to the underperformance of the business.

The revised LTIP will continue to rely on strong business performance, including growth in the company's share price, to deliver any level of vesting.

Directors fees: non-executive director fee remuneration was last increased on 1 July 2019. Since that time statutory increases to superannuation have also been absorbed within the total fee. Effective 1 July 2024, the Board resolved that the Company would pay the increase to the superannuation rate (from 11% to 11.5%) but that there would be no other increase in directors fees. This is reflected in the Board Fees shown in 4.9.1.

The level of energy and commitment to succeed in the Company is very strong, at all locations and levels.

The Board recognises the gains made in FY24 and is very appreciative of the efforts of all staff in this regard. Under Jane Norman's leadership we are confident we will realise the company's potential and we look forward to FY25 and beyond.

Yours sincerely

Mr Jeffrey Schneider
Chairman of the People & Remuneration Committee

REMUNERATION REPORT

CONTENTS

4.1 INTRODUCTION

This Remuneration Report (Report) details the approach to remuneration frameworks, outcomes and performance for Cooper Energy. The Remuneration Report forms part of the Directors' Report and provides shareholders with an understanding of the remuneration principles and practices in place for Key Management Personnel (KMP) for the reporting period.

4.2 KEY MANAGEMENT PERSONNEL COVERED IN THIS REPORT

In this Report, KMP are the people who have the authority and responsibility for planning, directing and controlling the activities of the Group, either directly or indirectly. They are:

- the Non-Executive Directors;
- the Managing Director and Chief Executive Officer; and
- selected executives on the Executive Leadership Team.

The Managing Director and Chief Executive Officer and select executives on the Executive Leadership Team are referred to in this Report as "Executive KMP". The following table sets out the KMP of the Group during the reporting period and the period they were KMP:

Name	Position	Period As KMP
Non-Executive Directors		
John Conde AO	Chairman	Full Year
Timothy Bednall	Non-Executive Director	Full Year
Giselle Collins	Non-Executive Director	Full Year
Elizabeth Donaghey	Non-Executive Director	Full Year
Jeffrey Schneider	Non-Executive Director	Full Year
Former Non-Executive KMP		
Vicky Binns[1]	Non-Executive Director	Part Year[1]
Executive KMP		
Jane Norman	Managing Director & Chief Executive Officer	Full Year
Chad Wilson[2]	Chief Operating Officer	Part Year[2]
Dan Young	Chief Financial Officer	Full Year
Eddy Glavas	Chief Commercial Officer	Full Year
Andrew Thomas[3]	Chief Exploration & Subsurface Officer	Full Year[3]

[1] Vicky Binns retired from the Board effective 9 November 2023.
[2] Chad Wilson commenced effective 23 October 2023.
[3] Andrew Thomas ceased as Executive KMP on 30 June 2024. Andrew leaves Cooper Energy on 30 September 2024.

REMUNERATION REPORT

4.3 REMUNERATION GOVERNANCE

4.3.1 PHILOSOPHY AND OBJECTIVES

The Company is committed to a remuneration philosophy that aligns with its business strategy and encourages superior performance and shareholder returns. Cooper Energy's approach towards remuneration is aimed at ensuring that an appropriate balance is achieved between:

- maximising sustainable growth in shareholder returns;
- operational and strategic requirements; and
- providing attractive and appropriate remuneration packages.

The primary objectives of the Company's remuneration policy are to:

- attract and retain high calibre employees;
- ensure that remuneration is fair and competitive with both peers and competitor employers;
- provide significant incentive to deliver superior performance (when compared to peers), against Cooper Energy's strategy and key business goals without rewarding conduct that is contrary to the Cooper Energy values or risk appetite;
- achieve the most effective returns (employee productivity), for total employee spend; and
- ensure remuneration transparency and credibility for all employees and in particular for Executive KMP.

Cooper Energy's policy is to pay fixed annual remuneration (FAR) at the median level, compared to resource industry benchmark data and supplement this with "at risk" remuneration to bring total remuneration within the upper quartile when outstanding performance is achieved.

4.3.2 PEOPLE & REMUNERATION COMMITTEE

The People & Remuneration Committee (which, as at the date of this report, is comprised of four non-executive directors, all of whom are independent) makes recommendations to the Board about remuneration strategies and policies for the executive KMP and considers matters related to organisational structure and operating model, company culture and values, diversity, succession for senior executives, and executive development and talent management. The ultimate responsibility for, and power to make company decisions with respect to these matters, remains with the full Board.

On an annual basis, the People & Remuneration Committee makes recommendations to the Board about the form of payment and incentives to executive KMP, and the amount. This is done with reference to Company performance and individual performance of the executive KMP, relevant employment market conditions, current industry practices and independent remuneration benchmark reports.

4.3.3 EXTERNAL REMUNERATION ADVISERS

The People & Remuneration Committee may consider advice from external advisors who are engaged by and report directly to the Committee. Such advice will typically cover non-executive director fees, executive KMP remuneration and advice in relation to equity plans.

The *Corporations Act 2001* requires companies to disclose specific details regarding the use of remuneration consultants. The mandatory disclosure requirements only apply to those advisors who provide a "remuneration recommendation" as defined in the *Corporations Act 2001*. The Committee did not receive any remuneration recommendations during the FY24 reporting period.

4.4 NATURE & STRUCTURE OF EXECUTIVE KMP REMUNERATION

Executive KMP remuneration during the reporting period consisted of a mix of:

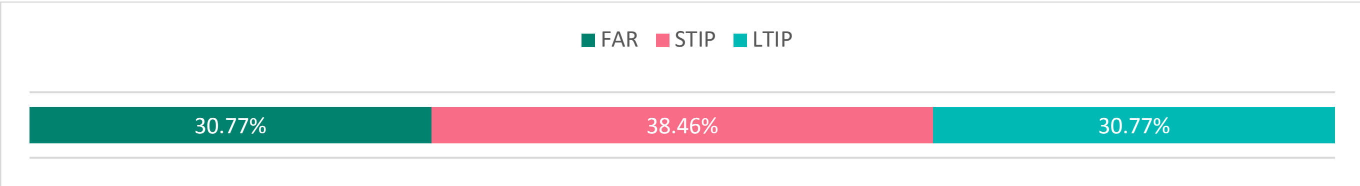
- Fixed annual remuneration (FAR);
- Short term incentive plan (STIP) participation;
- Benefits such as, internet allowance and car parking; and
- Long term incentive plan (LTIP) participation under the Company's amended equity incentive plan (EIP) approved by shareholders at the 2022 AGM.

It is the Company's policy that performance-based (or at-risk) pay forms a significant portion of the executive KMPs' total remuneration. The Company aims to achieve an appropriate balance between rewarding operational performance (through the STIP reward) and rewarding long-term sustainable performance (through the LTIP).

REMUNERATION REPORT

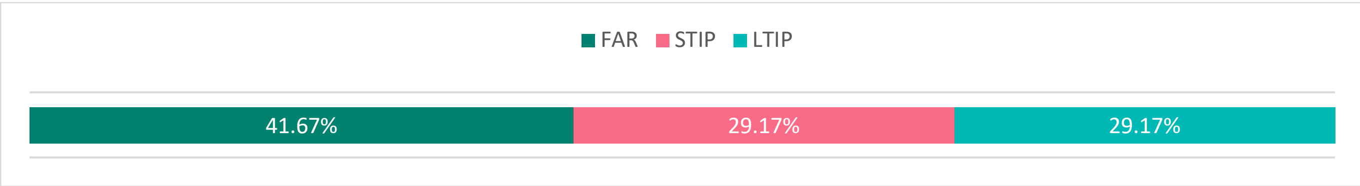
The Company's current remuneration profile for executive KMP (at maximum performance) is as follows:

MANAGING DIRECTOR & CEO

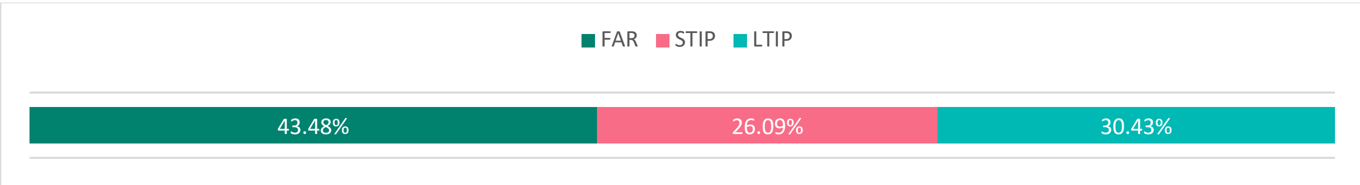


The above split of fixed and at risk pay reflects the ongoing remuneration for the Managing Director & CEO. For the first year the Managing Director's remuneration split was 28.57% FAR, 35.71% STIP and 35.71% LTIP. A higher LTIP applied to the first-year invitation was due to the timing of commencement with the Company, being 9 months into FY23. This was disclosed in our ASX announcement of 19 December 2022, and the share rights issue approved by shareholders at the 2023 Annual General Meeting.

CHIEF OPERATING OFFICER



OTHER EXECUTIVE KMP



4.4.1 REMUNERATION STRATEGY AND FRAMEWORK - LINKING REWARD TO PERFORMANCE

The remuneration strategy sets the remuneration framework and drives the design and application of remuneration for the Company, including executive KMP.

The remuneration strategy:

- encourages a strong focus on financial and operational performance, and motivates executive KMP to deliver sustainable business results and returns to the Company's shareholders, over the short and long term;
- attracts, motivates and retains appropriately qualified and experienced talent; and
- aligns executive and shareholder interests, through well designed performance incentives and equity linked plans.

The Board believes that remuneration should include a fixed component and at-risk or performance-related components, including both short term and long-term incentives.

This remuneration framework is shown in the table following, including how performance outcomes will impact remuneration outcomes for executive KMP. The Board will continue to review the remuneration framework to ensure it continues to align with the Company's strategic objectives and ensure shareholder alignment.

4.4.2 REMUNERATION STRATEGY AND FRAMEWORK – OVERVIEW

This current remuneration framework overview includes changes made to the STIP and LTIP during FY24. The inclusion of equity (performance rights) in STIP is effective from FY25 (performance year commencing 1 July 2024). Changes to LTIP were made in the December 2023 LTIP invitation. Testing of this LTIP invitation, for the purposes of vesting, will be in December 2026. Details of the STIP and LTIP that operated in FY24 are shown in 4.4.4 and 4.4.5 respectively.

REMUNERATION REPORT

	Performance Conditions	Remuneration Strategy/Performance Link
Fixed Annual Remuneration (FAR) Salary and other benefits (including statutory superannuation)	**Key Considerations** ▪ Scope of individual's role. ▪ Individual's level of knowledge, skills and expertise. ▪ Individual performance. ▪ Market benchmarking.	FAR is set to attract, retain and motivate the right talent to deliver the strategy and deliver the Company's financial and operational targets. For executives new to their role, the aim is to set FAR at relatively modest levels, compared to their peers, and to progressively increase as they gain experience and perform at higher levels. This links fixed remuneration to individual performance.
Short Term Incentive Plan (STIP) Annual incentive opportunity, delivered in cash and equity, based on Company and individual performance	**Company Performance** There are four key dimensions for which company performance is measured: ▪ Health, Safety, Environment, Sustainability and People & Culture. ▪ Production. ▪ Financial. ▪ Projects and Growth. The targets that were established for FY24 and the achievement level against these targets are outlined in 4.6.2 of this report. **Individual performance KPIs** Individual performance measures are agreed each year. The measures include key business objectives, while also being role-specific, i.e. related to individual and team specific responsibilities.	STIP performance conditions are designed to support the financial, operational and strategic direction of the Company and are clearly defined and measurable. The achievement of these conditions will in turn create shareholder value. A large proportion of outcomes are subject to the operational and financial targets of the Company or business unit, depending on the role of the executive, to ensure clear line of sight to outcomes that will create shareholder value. Strategy and project targets ensure that continued focus on future opportunities is maintained. Non-financial targets are aligned to core values (including safety and sustainability) and key strategic and growth objectives. Threshold, Target, and Stretch targets for each measure are set by the Board to ensure that a challenging performance-based incentive is provided. The Board has discretion to adjust STIP outcomes up or down to ensure appropriate company and individual outcomes are aligned with the shareholder experience and Cooper Energy values.
Long Term Incentive Plan (LTIP) Three-year incentive opportunity delivered through performance rights.	LTIP can reward executives subject to performance hurdles being met, with the allocation of performance rights. **Performance Measures** There are two equally weighted performance measures: ▪ Relative total shareholder return (RTSR), where performance requires a sustained superior share price performance of the Company compared to a peer group of companies. The peer group companies are ASX-listed companies in the oil and gas sector, with a range of market capitalisation. ▪ Absolute total shareholder return (ATSR). This measures the compound average growth rate (CAGR) over a three-year period.	Allocation of performance rights encourages executives to 'behave like shareholders' from the grant date. The performance rights are restricted and subject to risk of forfeiture at the end of the three-year performance period. The Company believes that encouraging its employees to become shareholders is the best way of aligning employee interests with those of the Company's shareholders. The LTIP can also act as a retention incentive for key talent (due to the three-year vesting period). RTSR and ATSR measures are designed to encourage executives to focus on the key performance drivers which underpin sustainable growth in shareholder value. The performance conditions are designed to ensure vesting can only occur where shareholders have enjoyed superior share price performance in relative (against peers) and absolute terms.

Total remuneration: The combination of these elements is designed to attract, retain and motivate appropriately qualified and experienced individuals, encourage a strong focus on performance, support the delivery of outstanding returns to shareholders, and align executive and shareholder interests through share ownership.

REMUNERATION REPORT

4.4.3 FIXED ANNUAL REMUNERATION (FAR)

FAR includes base salary (paid in cash) and statutory superannuation. Executives are paid FAR which is competitive in the markets in which the Company operates and is consistent with the responsibilities, accountabilities and complexities of the respective roles.

The Company benchmarks FAR for its executive KMP against resource industry market surveys (and, in particular, oil and gas companies) which are published annually. Additionally, the pay levels of executive KMP positions in the Company may be benchmarked against national market executive remuneration surveys. It is the Company's policy to position itself at the median level of the market when benchmarking FAR.

4.4.4 SHORT TERM INCENTIVE PLAN (STIP) - OVERVIEW

The STIP is an annual incentive opportunity delivered in cash (for FY24) based on a mix of Company and individual performance. The individual measures are a mixture of business unit and employee-specific goals. The key features of the STIP for FY24 were as follows:

STIP FY24 Plan Features	Details
What is the purpose of the STIP?	Motivate and reward individuals for their contribution to the annual performance of the Company.
How does the STIP align with the interests of Cooper Energy's shareholders?	The STIP is aligned to shareholder interests by encouraging individuals to achieve operational and business milestones in a balanced and sustainable manner whilst growing assets and total company value.
What is the vehicle of the STIP award?	The STIP award in FY24 is delivered in the form of a cash payment, payable in October. From FY25 an equity component will be included in STIP where the opportunity to receive performance rights under a deferred STIP award will be included. The deferred STIP element will mean that any grant of performance rights will vest 12 months after the initial grant date, provided the service conditions of current employment is met. Such rights are subject to forfeiture under certain conditions of the EIP rules. If the FY25 STIP results in an eligible grant of performance rights (equity) for the MD & CEO, prior to any such allocation, final approval of the shareholders will be sought at the 2025 AGM, consistent with ASX requirements.
What is the maximum award opportunity (% of FAR)?	Changes made during the FY24 performance period are as follows: (see tables below)

Managing Director & CEO

Maximum STIP (% of FAR)	FY24	FY25
Cash	125%	105%
Equity	0%	20%
Maximum STIP	125%	125%

Chief Operating Officer

Maximum STIP (% of FAR)	FY24	FY25
Cash	70%	60%
Equity	0%	10%
Maximum STIP	70%	70%

Other executive KMP

Maximum STIP (% of FAR)	FY24	FY25
Cash	50%	50%
Equity	0%	10%
Maximum STIP	50%	60%

What is the performance period?	Each year, the Board reviews and approves the performance criteria for the year ahead by approving a Company scorecard and individual performance contracts which are agreed with each executive KMP. The Company's STIP operates over a 12-month performance period from 1 July to 30 June.

REMUNERATION REPORT

How are the performance measures determined and what are their relative weightings?	The measurement of Company performance is based on the achievement of KPIs set out in the Company scorecard. See section 4.6.2 for the Company scorecard measures used for FY24. The KPIs focus on the core elements the Board believes are needed to successfully deliver the Company strategy and maximise sustainable shareholder returns. For each KPI in the scorecard, a base or threshold performance level is established as well as a Target and Stretch goal (Stretch being the maximum). Personal performance measures are agreed between each executive KMP and Cooper Energy each year. The relative weighting of Company scorecard and individual performance is as follows:

KMP	Company Scorecard	Individual Performance
Managing Director & CEO	75%	25%
Other Executive KMP	70%	30%

Performance measures are challenging, and maximum award opportunities are only achieved by outstanding performance. 50% of the maximum award opportunity will be awarded if the Company meets target level performance.

0% STIP will be awarded for performance achievement below a Threshold level.

0% STIP will be awarded if during any measurement period the Company sustains a fatality or major environmental incident.

Irrespective of the scorecard outcome, payment of any STIP is entirely at the discretion of the Board.

4.4.5 LONG TERM INCENTIVE PLAN (LTIP) - OVERVIEW

The key features of the grants made in the 2024 financial year (granted December 2023) are set out in the following table:

FY24 LTIP Plan Features	Details
What is the purpose of the LTIP?	The Company believes that encouraging its employees, including executive KMP, to become shareholders is the best way of aligning their interests with those of the Company's shareholders. Having a LTIP is also intended to be a retention incentive, with a vesting period of at least three years before securities under the plan are available to employees.
How is the LTIP aligned to shareholder interests?	Employees only benefit from the LTIP when there is sustained superior share price performance of the Company, including when compared to relevant peer group companies. This aligns the LTIP with the interests of shareholders.
What is the vehicle of the LTIP?	LTIP grants during the reporting period were entirely in the form of performance rights. A performance right is a right to acquire one fully paid share in the Company, provided specified performance hurdles are met.
What is the maximum annual LTIP grant (% of Fixed Remuneration)?	(see table below)

KMP	% of FAR
Managing Director & CEO*	100%
Other Executive KMP	70%

* The first LTIP invitation for the Managing Director & CEO that was issued in December 2023 was 125% of FAR due to the timing of the appointment. This was disclosed in our ASX announcement dated 19 December 2022.

What is the LTIP performance period?	The performance period is three years.
What are the performance measures?	There are two equally weighted performance measures: ▪ Relative total shareholder return (RTSR) (50%). Performance requires a sustained superior share price performance of the Company compared to a peer group of companies. The peer group companies are ASX-listed companies in the oil and gas sector, with a range of market capitalisation.

- Absolute total shareholder return (ATSR) (50%). ATSR is calculated as the compound average growth rate (CAGR) of the Company's share price over a 3-year period, and is expressed as a percentage.

RTSR and ATSR are common long-term incentive measures across ASX-listed companies and are aligned with shareholder returns. Relative measures ensure that maximum incentives are only achieved if Cooper Energy's performance exceeds that of its peers and therefore supports competitive returns against other comparable organisations. Absolute measurement rewards share price growth over a 3-year period.

Which companies make up the RTSR peer group?

The RTSR is measured as a percentile ranking compared to the following comparator group of listed entities: Beach Energy (BPT), Carnarvon Energy (CVN), Comet Ridge (COI), Empire Energy (EEG), Horizon Oil (HZN), Melbana Energy (MAY), Pancontinental Energy (PCL), Strike Energy (STX) and Tamboran Resources (TBN).

What is the vesting schedule?

RTSR (tranche 1) 50% of performance rights
The vesting criteria for performance rights (PRs) is based on the Company's RTSR performance, with the percentage of PRs which vest at the end of the performance period determined by the Company's RTSR percentile ranking as assessed against the peer group of companies.
Subject to the plan rules, the number of incentives which are achieved and will vest at the end of the performance period as a result of the Tranche 1 PRs will be the number which corresponds to the Company's RTSR as set out below:

RTSR percentile ranking	Percentage of tranche 1 performance rights to vest
Below 50th percentile	No performance rights
At 50th percentile	50% of performance rights
Between 50th percentile and 75th percentile	50% of performance rights plus 2% for each additional percentile
At or above 75th percentile	100% of performance rights

ATSR (tranche 2) 50% of performance rights
Subject to the plan rules, the number of PRs which are achieved and will vest at the end of the performance period as a result of the tranche 2 PRs will be the number which corresponds to the CAGR as set out below:

3-year CAGR	Percentage of tranche 2 performance rights to vest
Less than 10%	No performance rights
At 10%	50% of performance rights
Between 10% and 20%	50% of performance rights plus 5% for each additional percentile
20% or above	100% of performance rights

The vesting schedule reflects the Board's requirement that performance measures are challenging, and maximum award opportunities are only achieved by outstanding performance.

What happens on cessation of employment?

Generally, if an employee ceases employment prior to the vesting date (e.g., to take a position with another company), they will forfeit all awards. In the case of "qualifying leavers" as defined (examples of which include redundancy, retirement or incapacity), awards may be retained, unless the Board determines otherwise. The Board also has the discretion to determine that some or all awards may be retained upon cessation of employment.

What happens if there is a change of control?

In the event of a change of control, unless the Board determines otherwise, pro-rata vesting will occur on the basis of the proportion of the relevant performance period that has elapsed.

Who can participate in the LTIP?

Eligibility is generally restricted to executive KMP and members of the executive leadership team (ELT).

Will the Company make any changes to the LTIP for the grant to be made in the 2025 financial year (FY25)?

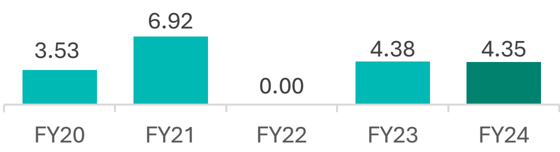
As indicated earlier in this Remuneration Report, a review of remuneration structure was undertaken in FY24. The Board is satisfied that the revised LTIP aligns executive and shareholder interests through the equity linked plan. No further changes are envisaged to the LTIP grant to be made in FY25.

REMUNERATION REPORT

4.5 COOPER ENERGY'S FIVE-YEAR PERFORMANCE AND LINK TO REMUNERATION

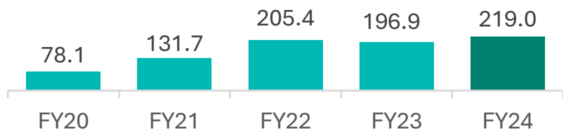
The following graphs illustrate the Company's five-year performance, which link to the remuneration strategy and framework:

SAFETY - TOTAL RECORDABLE INCIDENT FREQUENCY RATE
(events per hours worked, where a lower value is better)



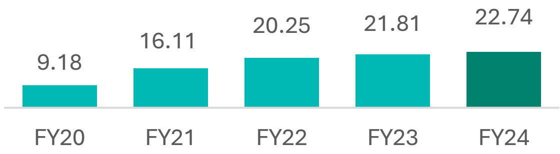
Links directly to Company STIP reward outcome as a HSEC & Sustainability KPI.

SALES REVENUE ($ MILLION)



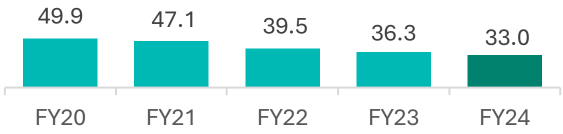
Links indirectly to Company STIP reward outcome as a Production & Financial KPI.

ANNUAL PRODUCTION (PJE)



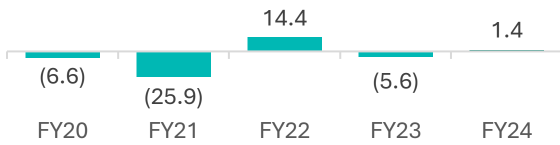
Links directly to Company STIP reward outcomes as a Production & Financial KPI.

PROVED & PROBABLE NATURAL GAS & OIL RESERVES (MMBOE)



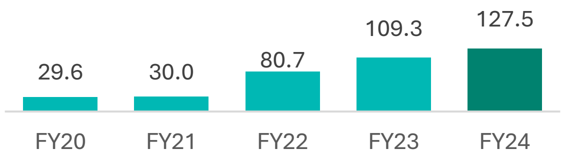
Links directly to Company STIP reward outcome as a Growth & Portfolio Management KPI.

FINANCIAL – UNDERLYING PROFIT AFTER TAX ($ MILLION)



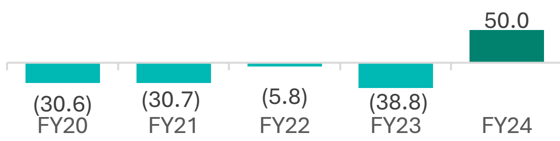
Links indirectly to Company STIP reward outcomes via Production & Financial KPIs.

FINANCIAL – UNDERLYING EBITDAX ($ MILLION)



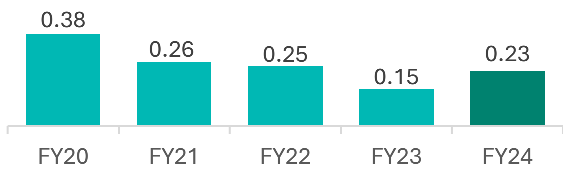
Links indirectly to Company STIP reward outcome as a Financial KPI.

FINANCIAL – TOTAL SHAREHOLDER RETURN (%)



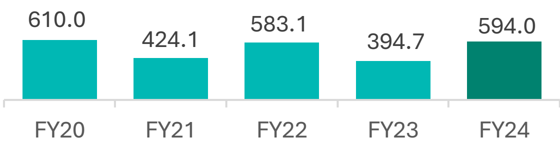
Links directly to Company LTIP reward outcome by increasing shareholder value.

SHARE PRICE – AS AT 30 JUNE ($ PER SHARE)



Links directly to Company LTIP reward outcome by increasing shareholder value compared to peers.

MARKET CAPITALISATION - AS AT 30 JUNE ($ MILLION)



Links directly to Company LTIP reward outcome by increasing shareholder value compared to peers.

In FY24, and in the past 5 years, dividends were not paid by the Company to its shareholders, nor was there a return of capital to shareholders, consistent with the growth reinvestment objectives of the Company.

REMUNERATION REPORT

4.6 2024 EXECUTIVE KMP PERFORMANCE AND REMUNERATION OUTCOMES

4.6.1 FIXED ANNUAL REMUNERATION OUTCOME

Planned increases to the executive KMP remuneration were communicated in last year's report.

However, these did not proceed in FY24 other than the statutory change to superannuation. The only exception was the Chief Financial Officer who took on additional responsibilities. The decision not to proceed with general increases for executive KMP in FY24 was consistent with the business conditions faced by the Company including cost containment objectives.

There has not been a general salary increase for executive KMP since 1 July 2022 other than for increases in statutory superannuation benefits. The Board determined that an increase to FAR would be applied effective 1 July 2024 including the increase in statutory superannuation. For the executive KMP, these increases range from 1.8% to 4.42% and are seen as comparable to our relevant peer companies and industry generally.

Fixed annual remuneration (FAR) effective 1 July 2024 is as follows:

Executive KMP	Position	Base Salary $	Superannuation $	Fixed Annual Remuneration $
Jane Norman	Managing Director & CEO	804,068	29,932	834,000
Chad Wilson	Chief Operating Officer	573,068	29,932	603,000
Dan Young	Chief Financial Officer	535,068	29,932	565,000
Eddy Glavas	Chief Commercial Officer	440,068	29,932	470,000
Andrew Thomas[1]	Chief Exploration & Subsurface Officer	469,708	29,932	499,640

[1] Andrew Thomas ceased as Executive KMP 30 June 2024. Andrew leaves Cooper Energy on 30 September 2024.

The next general review of base salaries will be 1 October 2025.

REMUNERATION REPORT

4.6.2 STIP PERFORMANCE OUTCOMES – COMPANY RESULTS

The Board determined a FY24 scorecard assessment result of 56.1/100 (56.1/%)

Performance Measure (FY24 Weighting)	Performance Measure Outcome	Result: Threshold	Target	Stretch
HSE, sustainability, people & culture (25%) Result: 21.3/25.0	▪ No LTIs > 3 days off work ▪ No high potential incidents ▪ No tier 1 or 2 process safety events ▪ 1 medical treatment case ▪ No environmental incidents > level 1 ▪ Maintained Climate Active net zero certification ▪ Three decarbonization projects implemented ▪ New Company strategy released ▪ Record employee survey participation ▪ Voluntary turnover below industry benchmark ▪ Stakeholder engagement to support project approvals			
Production (25%) Result: 2.5/25.0	▪ Sole/OGPP production of 50.1 TJ/d (excluding shutdown) ▪ CHN/AGP production of 10.8 TJ/d (excluding shutdown) ▪ PEL92 production of 360 bbls/d			
Financial (25%) Result: 22.3/25.0	▪ Production expenses of $59.6mm ▪ Net G&A of $14.5mm ▪ SIB capex below stretch			
Projects & growth (25%) Result: 10.0/25.0	▪ BMG wells decommissioning delivered safely, but costs exceeded threshold ▪ Gas marketing contracting equal to or above market price indicators, including 'as available' gas agreement to supply peaking power when required, capturing the value of firming renewables ▪ Planning and long lead items advanced for ECSP, but no overall FID			
FY24 performance				**56.1/ 100**

4.6.3 STIP PERFORMANCE OUTCOMES – INDIVIDUAL RESULTS

When the Company Scorecard result and individual performance outcomes were combined, the Board determined the FY24 STIP outcomes for the Executive KMP as follows:

	KMP Short Term Incentive (STIP) For The Year Ended 30 June 2024				
Executive KMP	STIP - % Of FAR at Target	STIP- % Of FAR at Maximum	Cash STIP $	% Earned of Maximum STIP Opportunity	% Forfeited of Maximum STIP Opportunity
Jane Norman	62.5%	125%	**642,438**	64.08%	35.92%
Chad Wilson[1]	35.0%	70%	**180,606**	44.48%	55.52%
Dan Young	25.0%	50%	**178,072**	64.17%	35.83%
Eddy Glavas	25.0%	50%	**141,716**	62.97%	37.03%
Andrew Thomas[2]	25.0%	50%	**154,277**	62.07%	37.93%

[1] Chad Wilson commenced on 23 October 2023. STIP projected to a full year would represent $261,748 gross or 64.47% of his maximum annual STIP opportunity.
[2] Andrew Thomas ceased as Executive KMP 30 June 2024. STIP represents payment for the full financial year. Andrew leaves Cooper Energy on 30 September 2024.

Managing Director & CEO individual performance

Jane Norman, the Managing Director and CEO, received a FY24 STIP payment of $642,438 gross. The calculation of this payment was as follows:

Jane Norman	Maximum Eligibility % FAR	Maximum Eligibility $	FY24 Result	FY24 STIP Gross Payment
Company Scorecard (75%)	93.75%	751,975	56 %	421,858
Individual performance (25%) *	31.25%	250,658	88 %	220,580
Total	**125.00%**	**1,002,633**		**642,438**

REMUNERATION REPORT

* The Managing Director & CEO's Individual performance was assessed by the Board as follows:

Performance Measure (Fy24 Weighting)	Performance Measure Outcome	Result – Threshold	Result – Target	Result – Maximum
Deliver improved performance of the Orbost Gas Processing Plant (OGPP) to achieve step change to company performance. **Weighting: 40%**	▪ Creation of a focused engineering group to drive plant performance. ▪ Appointment of new Chief Operating Officer (Chad Wilson); commenced October 2023. ▪ Appointment of new Plant Superintendent. ▪ Achieved average production rate ~50.1 TJ/d; higher than FY23 ~47 TJ/d. Includes production records set in Jan - Feb 2024 with instantaneous rates > 70 TJ/d achieved. ▪ Significant improvement project milestones delivered, including new media for polisher, polisher trace heating and insulation, 4-nozzel spray distributor, in-situ chemical clean trial.			
Successful completion of BMG decommissioning project to complete regulatory obligations. **Weighting: 20%**	▪ Seven well BMG decommissioning project delivered within the revised cost range as outlined in January 2024. ▪ Completion cost reflected in the 'below target outcome on the company scorecard. Technically the project was a success, and all seven wells were decommissioned. ▪ Project completed with no lost-time injuries and no significant environmental costs.			
Deliver organisational design and culture goals to increase strength of business leadership and accountability and improve staff engagement levels. **Weighting: 10%**	▪ Implementation of new organisational structure complete, including changes to ELT. ▪ Organisational capability has been improved and reset to a high performing culture to deliver on what is promised. ▪ Significant progress on cost out with ~$10m of annual costs removed, including a reduction in G&A and production expenses (Production Expense guidance revised down during the year). ▪ New company Vision, Values, Purpose and Strategy launched.			
Build investor relationships and deliver clear messaging to the market and other stakeholders to restore confidence in the future of COE. Enhance Shareholder returns including share price performance year on year, M&A activity, share buy backs and other activities to generate positive returns. **Weighting: 30%**	▪ Share price performance up 53% from $0.15/share to $0.23/share year-on year. ▪ Several new institutional investors brought into top 20 on register in past 6 months. ▪ Compliance with gas market regulations achieved including the Mandatory Gas Code of Conduct. ▪ Proactive engagement with Governments of all levels, with regulators such as NOPSEMA and industry bodies.			
FY24 Performance				**88 / 100**

REMUNERATION REPORT

For the year ended 30 June 2024

Other Executive Key Management Personnel Individual Performance

STIP for other executive KMP has a 70% weighting on the company scorecard and 30% individual performance weighting. Commentary on individual performance and FY24 STIP outcomes follow:

Chad Wilson Chief Operating Officer		Dan Young Chief Financial Officer	
▪ Commenced on 23 October 2023. ▪ Systematically advanced the OGPP Improvement Project, prioritising activities which delivered incremental performance improvements. ▪ Plant throughput improvements executed at both assets. ▪ Operations systems and processes were refined, adding greater discipline and rigour. ▪ Increased focus on production loss and plant reliability. ▪ Achieved significant reduction in production expenses through reduced contract services and improved waste management. ▪ Company safety and environment targets achieved.		▪ Company safety and environment targets achieved. ▪ Leadership growth included an expended portfolio including Contracts & Procurement and IT. ▪ Lead role in company Transformation to reduce cost base and drive efficiency. ▪ Maintained strong relations with all capital providers. ▪ Progressing funding options for ECSP including existing lenders and potential gas customer prepayments.	
Company performance	56.1%	Company performance	56.1%
Individual performance	84%	Individual performance	83%
FY24 STIP as % of maximum[1]	64%[1]	FY24 STIP as % of maximum	64%

[1] FY24 STIP pro-rated on basis of commencement date.

Andrew Thomas Chief Exploration & Subsurface Officer		Eddy Glavas Chief Commercial Officer	
▪ ELT oversight of the BMG wells decommissioning project with successful, safe completion of the program. ▪ Delivered value through subsurface review and selective approach to PEL 92 Cooper exploration and development projects. ▪ Supported corporate development activities including assessing, enhancing and maintaining growth opportunities. ▪ Company safety and environment targets achieved.		▪ Maintained strong relationships with gas customers, successfully completed gas contract extensions and price reviews and originated new peak gas products. ▪ Ongoing leadership in progressing growth opportunities. ▪ Successful stakeholder engagement with government agencies and industry regarding the Mandatory Gas Code of Conduct raising awareness of Cooper Energy's objectives and commitments to domestic gas supply. ▪ Robust economic modelling to support Commercial decisions and Treasury activity. ▪ Company safety and environment targets achieved.	
Company performance	56.1%	Company performance	56.1%
Individual performance	76%	Individual performance	79%
FY24 STIP as % of maximum	62%	FY24 STIP as % of maximum	63%

FORMER EXECUTIVE KEY MANAGEMENT PERSONNEL INDIVIDUAL PERFORMANCE

Ashley Haren Former General Manager People & Remuneration		Iain Macdougall Former General Manager HSE, Tech. Services & IT	
▪ Strong contribution to organisational change, including at ELT level. ▪ Lead change to leadership at both operated sites. ▪ Delivered cost-out initiatives and focus on ensuring recruitment activities lift organisational capability. ▪ Supported transition to new Head of People & Culture. ▪ Company safety and environment targets achieved.		▪ Lead preparation of FY23 Sustainability Report and narrative. ▪ Completed successful handover of Environment and Safety team responsibilities to new Chief Corporate Services Officer. ▪ Supported transition to new ELT. ▪ Company safety and environment targets achieved.	
Company performance	56.1%	Company performance	56.1%
Individual performance	84%	Individual performance	50%
FY24 STIP as % of maximum	64%	FY24 STIP as % of maximum	54%

REMUNERATION REPORT

4.6.4 LTIP OUTCOME

LTIP grants issued in December 2020 and tested in December 2023 (during FY24) had a percentile ranking of below 50th percentile and therefore no shares vested as a result of this testing.

This nil vesting outcome was as a result of the performance of the Company's share price against its peers over the measurement period. Over the three-year measurement period Cooper Energy's total shareholder return was -69% and it achieved a RTSR percentile rank of 0%. This resulted in a nil vesting outcome for all performance rights and share appreciation rights that were granted in December 2020.

LTIP grants issued in December 2021 (to be tested in December 2024) and December 2022 (to be tested in December 2025) involve grants of performance rights (50%) and share appreciation rights (50%). These plans will be tested against their respective peer groups. Vesting will rely on relative total shareholder return (RTSR) percentile rankings, as previously disclosed.

Details, including performance hurdles, of the LTIP grants issued in December 2023 (to be tested in December 2026) are included under 4.4.5 Long term incentive plan (LTIP) – overview.

There has been no vesting for the past three years of any LTIP
All performance rights and share appreciation rights granted in 2018, 2019 and 2020 have lapsed unvested

4.7 EXECUTIVE KMP EMPLOYMENT CONTRACTS

Each executive KMP has an ongoing employment contract. All executive KMP have termination benefits that are within the allowed limits under the *Corporations Act 2001*, without shareholder approval. Contracts include the treatment of entitlements on termination in the event of resignation, with notice or for cause.

Key terms for each Executive KMP are set out below:

Executive KMP	Notice by Cooper Energy	Notice by Executive KMP	Indemnity Agreement	Treatment on Termination by Cooper Energy
Jane Norman	6 months	6 months	Company provides indemnity agreement, Directors and Officers indemnity insurance and access to Company records.	Where the Managing Director is not employed for the full period of notice, a payment in lieu may be made. A payment in lieu of notice is based on fixed remuneration (base salary and superannuation). Upon termination, superannuation is not paid on accrued annual leave or long service leave. Unused personal leave is not paid out and is forfeited.
Other Executive KMP	6 months	3 months	Company provides indemnity agreement, Directors and Officers indemnity insurance and access to Company records.	Where an Executive KMP is not employed for the full period of notice, a payment in lieu may be made. Upon termination, superannuation is not paid on accrued annual leave or long service leave. Unused personal leave is not paid out and is forfeited.

Under the rules of the STIP and the EIP, if an executive KMP ceases employment prior to the vesting date of an incentive award (STIP and LTIP) (e.g., to take a position with another company), they will forfeit all awards.

In the case of "qualifying leavers" as defined (examples of which include redundancy, retirement or incapacity), awards may be retained, unless the Board determines otherwise. The Board also has a discretion to determine that some or all awards may be retained upon cessation of employment.

REMUNERATION REPORT

4.8 2024 REMUNERATION OUTCOMES FOR EXECUTIVE KMP

4.8.1 REMUNERATION REALISED BY EXECUTIVE KMP IN FY24 AND FY23 (NOT AUDITED)

The Company believes that providing details of the remuneration actually realised by current executive KMP is useful to shareholders. It provides clear and transparent disclosure of remuneration provided by the Company.

The table set out below shows amounts paid, and the cash value of any equity awards which vested, during the reporting period. It serves to answer the question: what was actually paid as compensation including salary, STIP and LTIP realised in the financial year and any other awards.

This information is a non-IFRS measure and is in addition to and different from the disclosures required by the *Corporations Act 2001* and Accounting Standards in the rest of the Remuneration Report including the tables in sections 4.8.2 and 4.9.2. The information in section 4.8.1 is not audited.

The total benefits delivered during the reporting period and set out in the table below comprise the following elements:

- FAR is base salary and superannuation (statutory and salary sacrifice).
- STIP cash payment made in October each year. The STIP payments shown here correspond to the combined company scorecard and individual performance outcomes from the prior financial year. Currently, STIP awards are assessed and finalised in August and paid in October, in arrears, for the previous financial year. As a result, the amounts shown in the 2024 row, relate to STIP payments in respect of FY23. These amounts were assessed and approved by the Board in August 2023 and disclosed in 4.6.3 of the remuneration report for the year ended 30 June 2023. The STIP payments shown here align to the financial year when they were actually paid, while the table in section 4.8.2 aligns STIP payments to the financial year to which they relate.
- LTIP has not realised any vesting in the period stated, as none of the partial or full vesting thresholds were met (refer section 4.6.4).

Executive KMP	Financial year	FAR $	STIP $	LTIP $	Other $	Total $
Jane Norman[1]	**2024**	**802,105**	**57,144**	**-**	**407,684**	**1,266,933**
	2023	231,017	-	-	401,801	632,818
Chad Wilson[2]	**2024**	**403,602**	**-**	**-**	**290,212**	**693,814**
	2023	-	-	-	-	-
Dan Young[3]	**2024**	**555,000**	**72,128**	**-**	**6,741**	**633,869**
	2023	516,065	-	-	66,299	582,364
Eddy Glavas	**2024**	**450,106**	**45,360**	**-**	**6,741**	**502,207**
	2023	448,000	175,552	-	6,462	630,014
Andrew Thomas[4]	**2024**	**497,106**	**50,490**	**-**	**6,741**	**554,337**
	2023	495,000	190,519	-	6,462	691,981

[1]Jane Norman commenced as Managing Director & CEO on 20 March 2023 and her entitlements for 2023 are prorated. "Other" remuneration realised in 2023 includes $400,000 which represents 50% of a sign on bonus. The remaining 50% ($400,000) was payable on the first anniversary of company service and shown in the 2024 "Other" figure. The Company considered this sign on bonus to be a reasonable assessment for the value of incentives forgone from her previous employment. These contractual arrangements were disclosed in an ASX announcement dated 19 December 2022.
[2]Chad Wilson commenced as Chief Operating Officer on 23 October 2023. His entitlements for 2024 are prorated. "Other" remuneration realised includes $290,000 which represents 50% of a sign on bonus. The remaining 50% is payable on the first anniversary of company service. The Company considered this sign on bonus to be a reasonable assessment for the value of incentives forgone from his previous employment.
[3] Dan Young's "Other" remuneration realised included sign on and relocation costs in FY2023. The Company considered this sign on bonus to be a reasonable assessment for the value of incentives forgone from his previous employment.
[4] Andrew Thomas ceased as Executive KMP 30 June 2024. 2024 payments are for the full year. Andrew leaves Cooper Energy on 30 September 2024.

REMUNERATION REPORT

4.8.2 TABLE OF EXECUTIVE KMP STATUTORY REMUNERATION DISCLOSURE FOR FY24 AND FY23

The following table provides IFRS aligned disclosures on KMP remuneration required by the Corporations Act 2001 and Accounting Standards and is audited. By contrast with the table in section 4.8.1, which discloses amounts paid in respect of Executive KMP and the cash value of equity awards which vested during the reporting period, the disclosures provided in the following table present the KMP remuneration costs incurred and accrued during the reporting period. Amounts included as STIP and LTIP in section 4.8.1 represent realised benefits to Executive KMP during the reporting period, whilst the amounts shown in the table below as STIP and LTIP represent benefits incurred during the reporting period (LTIP grants are subject to vesting conditions described in section 4.4.5).

		Benefits									
		Short-term			Long-term	Post-employment	Share based remuneration[4]	Post KMP Payments[5]			
		Base salary	STIP[1]	Other short-term benefits[2]	Long service leave	Superannuation[3]	LTIP	Base salary[6]	Severance	LTIP[7]	Total
Executive KMP	**FY**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**	**$**
Jane Norman[8]	**2024**	**774,707**	**642,438**	**407,684**	**-**	**27,398**	**114,038**	**-**	**-**	**-**	**1,966,265**
	2023	221,747	57,144	401,801	-	9,270	-	-	-	-	689,962
Chad Wilson[9]	**2024**	**383,053**	**180,606**	**290,212**	**-**	**20,549**	**46,178**	**-**	**-**	**-**	**920,598**
	2023	-	-	-	-	-	-	-	-	-	-
Dan Young[10]	**2024**	**527,601**	**178,072**	**6,741**	**-**	**27,399**	**238,676**	**-**	**-**	**-**	**978,489**
	2023	490,773	61,824	76,603	-	25,292	237,800	-	-	-	892,292
Eddy Glavas	**2024**	**422,708**	**141,716**	**6,741**	**11,090**	**27,399**	**236,144**	**-**	**-**	**-**	**845,798**
	2023	422,708	45,360	6,462	14,654	25,292	257,322	-	-	-	771,798
Andrew Thomas[11]	**2024**	**469,708**	**154,277**	**6,741**	**12,323**	**27,399**	**260,984**	**133,943**	**379,379**	**309,992**	**1,754,746**
	2023	469,708	50,490	6,462	17,940	25,292	284,486	-	-	-	854,378
Former Executive KMP	**FY**										
Ashley Haren[12]	**2024**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	2023	289,708	34,020	6,462	-	25,292	97,702	-	-	-	453,184
Iain MacDougall[13]	**2024**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	2023	454,708	37,440	6,462	13,850	25,292	278,072	-	-	-	815,824
David Maxwell[14]	**2024**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	2023	666,573	150,000	47,316	33,656	17,530	566,677	293,034	-	1,239,071	3,013,857
Mike Jacobsen[15]	**2024**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	2023	395,590	38,250	410	9,211	21,077	230,335	262,852	319,515	420,132	1,697,372
Amelia Jalleh[16]	**2024**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	2023	375,229	-	5,934	-	23,185	241,148	-	-	-	645,496
Totals	**2024**	**2,577,777**	**1,297,109**	**718,119**	**23,413**	**130,144**	**896,020**	**133,943**	**379,379**	**309,992**	**6,465,896**
	2023	3,786,744	474,528	557,912	89,311	197,522	2,193,542	555,886	319,515	1,659,203	9,834,163

REMUNERATION REPORT

[1] Refer to 4.6.3 for STIP amount earned in FY24 which will be paid in FY25.
[2] Other short-term benefits include fringe benefits, car parking, sign on bonuses, relocation and other benefits. Other short-term benefits such as short-term compensated absences, short-term cash profit-sharing and other bonuses are not applicable to executive KMP in FY24.
[3] Superannuation is the only applicable post-employment benefit i.e., no pension or similar benefits for executive KMP. Superannuation includes the amounts required to be contributed by the Company and does not include amounts salary sacrificed.
[4] In accordance with the requirements of the Accounting Standards, remuneration includes a proportion of the value of the equity-linked compensation determined as at the grant date of the PRs and progressively expensed over the vesting period. The amount allocated as remuneration is not relative to or indicative of the actual benefit, if any, that may ultimately be realised should the equity instruments vest. The value of the PRs was determined in accordance with AASB 2 Share-based Payments and is discussed in Section 4.8.3 below and in more detail in Note 26 of the Notes to the Financial Statements.
[5] Base salary and severance are termination benefits and have been accounted for as such.
[6] Includes base salary, other short-term benefits and superannuation.
[7] Relate to LTIP awards made in December 2021, 2022 and 2023 which have not yet been fully expensed as the three-year testing period has not finished. These are non-cash expenses for LTIP grants that have not yet vested. These rights remain on foot for qualifying leavers and vesting of these grants remain contingent on the performance hurdles noted in section 4.4.5.
[8] Jane Norman commenced as Managing Director & CEO on 20 March 2023 and her entitlements for 2023 are prorated. “Other short term benefits” remuneration realised in 2023 includes $400,000 which represents 50% of a sign on bonus. The remaining 50% ($400,000) was payable on the first anniversary of company service and shown in the 2024 “Other short term benefits” figure. The Company considered this sign on bonus to be a reasonable assessment for the value of incentives forgone from her previous employment.
[9] Chad Wilson commenced as Chief Operating Officer on 23 October 2023. His entitlements for 2024 are prorated. “Other short term benefits” remuneration realised in 2024 includes $290,000 which represents 50% of a sign on bonus. The remaining 50% is payable on the first anniversary of company service. The Company considered this sign on bonus to be a reasonable assessment for the value of incentives forgone from his previous employment.
[10] Dan Young’s “Other short term benefits” remuneration realised included sign on and relocation costs in 2023. The Company considered this sign on bonus to be a reasonable assessment for the value of incentives forgone from his previous employment.
[11] Andrew Thomas ceased as an executive KMP effective 30 June 2024 but entitlements reflect the full period until his leaving date on 30 September 2024.
[12] Ashley Haren ceased as an executive KMP effective 30 June 2023 but entitlements reflect the full period until his retirement effective 5 July 2024.
[13] Iain MacDougall ceased as an executive KMP effective 30 June 2023 but entitlements reflect the full period until his leaving date on 5 February 2024.
[14] David Maxwell ceased as an executive KMP effective from 20 March 2023, but entitlements reflect the full period until his retirement on 3 July 2023. Other includes accommodation costs.
[15] Mr Jacobsen ceased as an executive KMP effective from 24 April 2023, but entitlements reflect the full period until his leaving date of 23 October 2023.
[16] Ms Jalleh ceased as an executive KMP effective from 19 May 2023, and her entitlements for 2023 are prorated.

No cash-settled share-based payment transactions or other forms of share-based payment compensation (including hybrids) were made by the Company. As noted in section 4.6.4, none of the PRs or SARs scheduled for potential vesting in either FY23 or FY24 – namely PRs and SARs granted in December 2019 and December 2020 – met any partial or full vesting thresholds. As such, all of these PRs and SARs lapsed unvested.

REMUNERATION REPORT

4.8.3 PERFORMANCE RIGHTS ACCOUNTING FOR THE REPORTING PERIOD

The value of the performance rights (PRs) issued under the EIP is recognised as share based payments in the Company's statement of comprehensive income and amortised over the vesting period. PRs were granted under the EIP on 11 December 2023.

PRs are granted for no consideration and employees receive no cash benefit at the time of receiving the rights.

The cash benefit, if any, will be received by the employee following the sale of the resultant shares, but this can only be achieved after the rights have vested and the shares are issued. Further, the rights can only vest when the relative total shareholder return (RTSR) and absolute total shareholder return (ATSR) thresholds described in section 4.4.5 have been achieved.

PRs granted under the EIP were valued by an independent consultant applying a Monte Carlo simulation model to determine the probability of achievement of the RTSR and ATSR against performance conditions.

The value of PRs shown in the tables below are the accounting fair values for grants in the reporting period:

	Performance rights (equity incentive plan)			
	No. of rights granted during period	Fair value of rights at grant date ($)	No. of rights vested during period	% of all rights vested from first award to 30 June 2024
Directors				
Jane Norman	8,378,307	586,481	-	0%
Executive KMP				
Chad Wilson	3,392,657	237,486	-	0%
Dan Young	3,064,101	214,487	-	0%
Eddy Glavas	2,632,860	184,300	-	14%
Andrew Thomas[1]	2,907,782	203,545	-	17%

[1] Andrew Thomas ceased as executive KMP 30 June 2024. Andrew leaves Cooper Energy on 30 September 2024.

The vesting date of the PRs granted on 11 December 2023 is 11 December 2026. The estimated fair value of these rights is $0.07 per right and the share price on grant date was $0.10. The performance period for these PRs commenced on 11 December 2023.

4.8.4 MOVEMENT IN INCENTIVE RIGHTS

The movement during the reporting period in the number of PRs granted but not exercisable over ordinary shares in Cooper Energy held, directly, indirectly or beneficially, by each executive KMP, including their related parties, is as follows:

Performance rights (equity incentive plan)	Held at 1 July 2023	Granted	Lapsed	Vested & exercised	Held at 30 June 2024
Directors					
Jane Norman[1]	-	8,378,307	-	-	8,378,307
Executive KMP					
Chad Wilson[1]	-	3,392,657	-	-	3,392,657
Dan Young	1,556,935	3,064,101	-	-	4,621,036
Eddy Glavas	1,731,917	2,632,860	426,217	-	3,938,560
Andrew Thomas[2]	1,914,372	2,907,782	471,346	-	4,350,808

No share appreciation rights were granted in FY24. The revised LTIP described in 4.4.5 means that only PRs will be awarded from the LTIP invitation of 11 December 2023, and provided that performance hurdles described in 4.4.5 are satisfied.

REMUNERATION REPORT

From previous LTIP grants (those granted in December 2021 and 2022), share appreciation rights represent the right to receive a quantity of shares based on an amount equal to the difference in share price at grant date and test date. The movement during the reporting period in the number of SARs granted but not exercisable over ordinary shares in Cooper Energy held, directly, indirectly or beneficially, by each executive KMP, including their related parties, is as follows:

Share Appreciation Rights (Equity Incentive Plan)	Held at 1 July 2023	Granted	Lapsed	Vested & Exercised	Held at 30 June 2024
Directors					
Jane Norman[1]	-	-	-	-	-
Executive KMP					
Chad Wilson[1]	-	-	-	-	-
Dan Young	4,542,590	-	-	-	4,542,590
Eddy Glavas	5,167,133	-	1,364,678	-	3,802,455
Andrew Thomas[2]	5,711,629	-	1,509,174	-	4,202,455

[1] Jane Norman and Chad Wilson were included in LTIP for the first time in December 2023. Jane's Norman's allocation of PRs were approved by shareholders in the AGM in November 2023.
[2] Andrew Thomas ceased as an executive KMP effective 30 June 2024. Vesting of the balance held at 30 June 2024 remains subject to meeting market conditions of the award.

4.8.5 DIRECTORS & EXECUTIVES MOVEMENT IN SHARES

The movement during the reporting period in the number of ordinary shares in Cooper Energy held, directly, indirectly or beneficially, by each KMP, including their related parties, is as follows:

Ordinary shares	Held at 1 July 2023	Purchases	Received on vesting of PRs & SARs	Sales	Held at 30 June 2024
Directors					
John Conde AO	1,904,254	-	-		1,904,254
Jane Norman	-	-	-	-	-
Timothy Bednall	270,499	50,000	-	-	320,499
Giselle Collins	160,000	-	-	-	160,000
Elizabeth Donaghey	879,000	300,000	-	-	1,179,000
Jeffrey Schneider	2,423,232	-	-	-	2,423,232
Executive KMP					
Chad Wilson[1]	-	-	-	-	-
Dan Young	-	-	-	-	-
Eddy Glavas	1,424,203	-	-	1,346,461	77,742
Andrew Thomas[2]	5,963,633	-	-	-	5,963,633

[1] Chad Wilson commenced as an executive KMP effective 23 October 2023.
[2] Andrew Thomas ceased as an executive KMP effective 30 June 2024.

Options
No options were issued (or forfeited) during the year.

REMUNERATION REPORT

4.9 NATURE OF NON-EXECUTIVE DIRECTOR REMUNERATION

Non-executive directors are remunerated solely by way of fees and statutory superannuation. Their remuneration is reviewed annually to ensure that the fees reflect their responsibilities and the demands placed on them. Non-executive directors do not receive any performance-related remuneration.

4.9.1 NON-EXECUTIVE DIRECTOR FEE STRUCTURE

The maximum aggregate remuneration pool for non-executive directors, as approved by shareholders at the Company's 2018 AGM, is $1.25 million. The non-executive directors' fee structure for the reporting period (FY24) was as follows:

Role	Board Fee	Audit Committee	Risk & Sustainability Committee	People & Remuneration Committee	Governance & Nomination Committee
Chairman*	$240,000	$20,000	$20,000	$20,000	$0
Member	$115,000	$10,000	$10,000	$10,000	$10,000

Effective from 1 July 2024 (FY25), the Board resolved to adjust the fee structure to reflect the increase to the statutory superannuation rate from 11.00% to 11.50%. This is the first increase in directors fees since July 2019. The table below shows this adjustment to take effective 1 July 2024.

Role	Board Fee	Audit Committee	Risk & Sustainability Committee	People & Remuneration Committee	Governance & Nomination Committee
Chairman*	$240,081	$20,090	$20,090	$20,090	$0
Member	$115,518	$10,045	$10,045	$10,045	$10,045

*Where the Chairman of the Board is a member of a committee, they will not receive any additional committee fees.

Remuneration paid to the non-executive directors for the reporting period and for the previous reporting period is shown in the table in Section 4.9.2. The fees paid in 2024 were reduced slightly to recognise a minor over payment in 2023 relating to superannuation. By the completion of 2024 this minor over payment was recovered in full.

The Company has entered into written letters of appointment with its non-executive directors. The term of the appointment of a non-executive director is determined in accordance with the Company's Constitution and is subject to the provisions of the Constitution dealing with retirement, re-election and removal of non-executive directors. The Constitution provides that all non-executive directors of the Company are subject to re-election by shareholders by rotation every three years. The Company has entered into indemnity, insurance and access agreements with each of the non-executive directors under which the Company will, on the terms set out in the agreement, provide an indemnity, maintain an appropriate level of Directors' and Officers' indemnity insurance and provide access to Company records.

REMUNERATION REPORT

4.9.2 TABLE OF NON-EXECUTIVE KMP REMUNERATION FOR 2024 AND 2023 FINANCIAL YEARS

		Benefits						
		Short term			Long term	Post-employ-ment	Share based remuneration	
Current non-executive directors (NED)[1]		Fees	STIP[2]	Other short-term benefits	Long service leave	Super-annuation[3]	LTIP	Total
		$	$	$	$	$	$	$
John Conde AO	**2024**	**215,233**	**-**	**-**	**-**	**23,676**	**-**	**238,909**
	2023	218,182	-	-	-	22,909	-	241,091
Tim Bednall	**2024**	**136,043**	**-**	**-**	**-**	**14,965**	**-**	**151,008**
	2023	131,818	-	-	-	13,841	-	145,659
Giselle Collins	**2024**	**133,081**	**-**	**-**	**-**	**14,639**	**-**	**147,720**
	2023	122,727	-	-	-	12,886	-	135,613
Elizabeth Donaghey	**2024**	**136,043**	**-**	**-**	**-**	**14,965**	**-**	**151,008**
	2023	131,818	-	-	-	13,841	-	145,659
Jeffrey Schneider	**2024**	**130,037**	**-**	**-**	**-**	**14,304**	**-**	**144,341**
	2023	131,818	-	-	-	13,841	-	145,659
Vicky Binns[4]	**2024**	**47,221**	**-**	**-**	**-**	**5,194**	**-**	**52,415**
	2023	136,818	-	-	-	14,366	-	151,184
Hector Gordon[5]	**2024**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	2023	136,818	-	-	-	14,366	-	151,184
Totals	**2024**	**797,658**	**-**	**-**	**-**	**87,743**	**-**	**885,401**
	2023	1,009,999	-	-	-	106,050	-	1,116,049

[1] Non-executive directors do not participate in the LTIP.
[2] Non-executive directors are not eligible for STIP payments.
[3] Superannuation includes the amounts required to be contributed by the Company and does not include amounts salary sacrificed.
[4] Vicky Binns retired from the Board effective 9 November 2023
[5] Hector Gordon retired from the Board effective 23 June 2023.

End of remuneration report.

DIRECTORS' STATUTORY REPORT

5. PRINCIPAL ACTIVITIES

Cooper Energy is an upstream gas and oil exploration and production company whose primary purpose is to secure, find, develop, produce and sell hydrocarbons. These activities are undertaken either solely or via unincorporated joint ventures. There was no significant change in the nature of these activities during the year.

6. OPERATING AND FINANCIAL REVIEW

Information on the operations and financial position of Cooper Energy and its business strategy and prospects is set out in the Operating and Financial Review.

7. DIVIDENDS

The Directors do not recommend the payment of a dividend and no amount has been paid or declared by way of dividends since the end of the previous financial year, or to the date of this report.

8. ENVIRONMENTAL REGULATION

The Company is a party to various exploration, development and production licences or permits. In most cases, the licence or permit terms specify the environmental regulations applicable to gas and oil operations in the respective jurisdiction. The Group aims to ensure that it complies with the identified regulatory requirements in each jurisdiction in which it operates. There have been no significant known breaches of the environmental obligations of the Group's licences or permits.

9. LIKELY DEVELOPMENTS

Other than disclosed elsewhere in the Financial Report (including the Operating and Financial Review under the heading "Outlook"), further information about likely developments in the operations of the Group and the expected results of those operations in future financial years has not been included in this report because disclosure of the information would likely result in unreasonable prejudice to the consolidated entity.

10. DIRECTORS' INTERESTS

The relevant interest of each Director in ordinary shares and options over shares issued by the parent entity as notified by the Directors to the Australian Stock Exchange in accordance with S205G(1) of the Corporations Act 2001, at the date of this reports is as follows:

	Ordinary Shares	Performance Rights	Share Appreciation Rights
Mr J. Conde AO	1,904,254	Nil	Nil
Ms J. Norman	Nil	8,378,307	Nil
Mr T. Bednall	320,499	Nil	Nil
Ms G. Collins	160,000	Nil	Nil
Ms E. Donaghey	1,179,000	Nil	Nil
Mr J. Schneider	2,423,232	Nil	Nil

11. SHARE OPTIONS AND RIGHTS

At the date of this report, there are no unissued ordinary shares of the parent entity under option. At the date of this report, there are 62,738,389 outstanding PRs and 43,758,208 SARs under the EIP approved by shareholders at the 2022 AGM.

During the financial year 8,506,969 shares were issued as a result of PRs exercised, none of these shares was issued under the EIP to KMPs. At the date of this report, no PRs have vested and been exercised subsequent to 30 June 2024.

12. EVENTS AFTER FINANCIAL REPORTING DATE

Refer to Note 29 of the Notes to the Financial Statements.

13. PROCEEDINGS ON BEHALF OF THE COMPANY

No person has applied to the Court under section 237 of the Corporations Act 2001 for leave to bring proceedings on behalf of the Company, or to intervene in any proceedings to which the Company is a party for the purpose of taking responsibility on behalf of the Company for all or part of the proceedings.

DIRECTORS' STATUTORY REPORT

14. INDEMNIFICATION AND INSURANCE OF DIRECTORS AND OFFICERS

14.1 Indemnification
The parent entity has agreed to indemnify the current Directors and Officers, and past Directors and Officers, of the parent entity and its subsidiaries, where applicable, against all liabilities (subject to certain limited exclusions) to persons (other than the parent entity and its subsidiaries) which arise out of the performance of their normal duties as a Director or Officer, unless the liability relates to conduct involving a lack of good faith. The parent entity has agreed to indemnify the Directors and Officers against all costs and expenses (other than certain excluded legal costs) incurred in defending an action that falls within the scope of the indemnity and any resulting payments.

14.2 Insurance premiums
During the financial year, the parent entity has paid insurance premiums in respect of Directors' and Officers' liability and legal insurance contracts for current and former Directors and Officers of the parent entity. The insurance contracts relate to costs and expenses incurred by the relevant Directors and Officers in defending proceedings, whether civil or criminal and whatever their outcome and other liabilities that may arise from their position, with exceptions including conduct involving a wilful breach of duty or improper use of information or position to gain a personal advantage. The insurance contracts outlined above do not contain details of premiums paid in respect of individual Directors or Officers of the parent entity.

15. INDEMNIFICATION OF AUDITORS

To the extent permitted by law, the Company has agreed to indemnify its auditors, Ernst & Young, as part of the terms of its audit engagement agreement against claims by third parties arising from the audit (for an unspecified amount) except in the case where the claim arises because of Ernst & Young's negligent, wrongful or wilful acts or omissions. No payment has been made to indemnify Ernst & Young during or since the financial year.

16. AUDITOR'S INDEPENDENCE DECLARATION

The auditor's independence declaration is set out on page 149 and forms part of the Directors' report for the financial year ended 30 June 2024.

17. NON-AUDIT SERVICES

The amounts paid and payable to the auditor of the Group, Ernst & Young and its related practices for non-audit services provided during the year was $62,000 (2023: $49,500). The directors are satisfied that the provision of non-audit services is compatible with the general standard of independence for auditors imposed by the Corporations Act 2001. The nature and scope of each type of non-audit service provided means that auditor independence was not compromised.

18. AUDIT TENDER

As noted in last year's annual report, the Directors elected to put the Group's audit out to tender, with effect from the financial year commencing 1 July 2024.

Ernst & Young have been the Group's auditor for over ten years. The tender was designed to assist the Audit Committee in continuing to assess the quality and effectiveness of the external audit process. The evaluation criteria for the audit tender comprised:

- Firm qualifications in serving clients in the upstream gas & oil industry
- Engagement team experience & expertise, including the involvement of other specialists
- Audit service process overview, tailored to Cooper Energy's business
- Quality assurance, including internal processes and results of external inspections
- Internal practices to ensure compliance with independence requirements
- Fee and other key terms & conditions

The tender was undertaken, as foreshadowed, in the course of H2 FY24. Following a review of, and discussions with, a number of the audit firms, a request for proposal (RFP) was sent to each of Deloitte Touche Tohmatsu Limited, Ernst & Young, KPMG and PricewaterhouseCoopers.

Each firm was given access to a data room containing select financial, operational and ESG related matters. Additionally, each firm met with the Chair of the Audit Committee, and separately with management including the Managing Director & CEO, the CFO, and the Group Finance Manager.

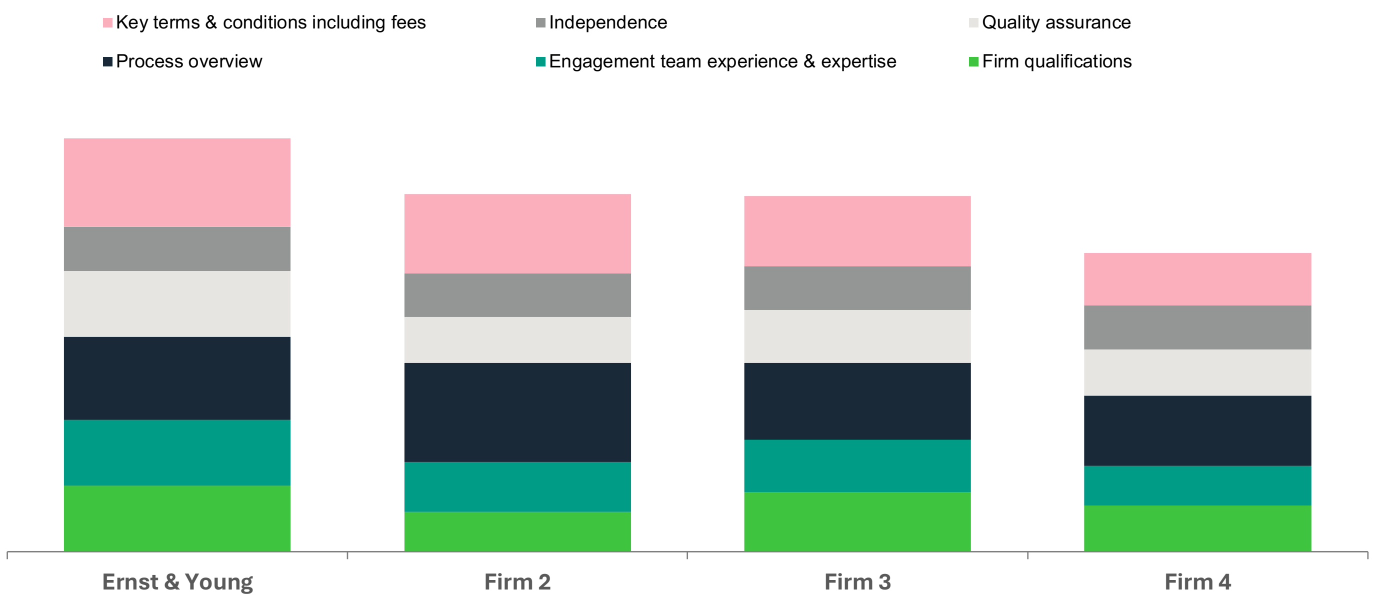
These meetings enabled each firm to ask questions regarding the critical business issues, the tender evaluation criteria, the Group's approach to sustainability generally including climate related financial disclosures specifically, and other matters important to the Directors and management as it pertains to the audit.

Written responses to the RFP were submitted to a steering committee which comprised the Chair of the Audit Committee along with senior members of management.

Together with the submission of each firm's proposal, the firms were also invited to present their capabilities for both the audit, as well as in areas that complement the audit, including climate related financial disclosures and sustainability, and in IT/technology. These capabilities were presented at face-to-face meetings with the Chair of the Board, the Chair of the Audit Committee, the Managing Director & CEO, the CFO, the Group Finance Manager and the Environment & Sustainability Manager.

DIRECTORS' STATUTORY REPORT

The relative scores/results of the evaluation are summarized in the following chart.



The Audit Committee recommended to the Board to continue the appointment of Ernst & Young as the Group's external auditor, while identifying certain opportunities for improvement by them. The Board approved the Audit Committee's recommendation, and resolved to continue the appointment Ernst & Young for the financial year ending 30 June 2025.

Ernst & Young are required to rotate the audit partner responsible for the Group's audit every five years and, as a result, the current lead audit partner, Darryn Hall, having served since the financial year ending 30 June 2021, will rotate after the financial year ending 30 June 2025.

19. ROUNDING

The Group is of a kind referred to in ASIC Corporations (Rounding in Financial/Directors' Reports) Instrument 2016/191 dated 24 March 2016 and in accordance with that Legislative Instrument, amounts in the financial report have been rounded to the nearest thousand dollars, unless otherwise stated.

This report is made in accordance with a resolution of the Directors.

Mr John C. Conde AO
Chairman
Dated at Adelaide 27 August 2024

Ms Jane L. Norman
Managing Director & CEO

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Notes	2024 $'000	2023 (restated) $'000
Revenue from gas and oil sales	2	**219,047**	196,885
Cost of sales	2	**(167,321)**	(164,379)
Gross profit		**51,726**	32,506
Other income	2	**3,355**	-
Other expenses	2	**(147,440)**	(110,722)
Finance income	18	**3,484**	3,019
Finance costs	18	**(36,219)**	(29,496)
Loss before tax		**(125,094)**	(104,693)
Income tax (expense)/benefit	3	**(915)**	19,185
Petroleum resource rent tax benefit	3	**11,900**	25,016
Total tax benefit		**10,985**	44,201
Loss after tax for the period attributable to shareholders		**(114,109)**	(60,492)
Other comprehensive income/(expenditure)			
Items that will not be reclassified subsequently to profit or loss			
Net gain/(loss) on equity instruments recorded at fair value through other comprehensive income	19	**(412)**	648
Other comprehensive income/(expenditure) for the period net of tax		**(412)**	648
Total comprehensive loss for the period attributable to shareholders		**(114,521)**	(59,844)
		Cents	Cents
Basic loss per share	4	**(4.3)**	(2.3)
Diluted loss per share	4	**(4.3)**	(2.3)

The above Consolidated Statement of Comprehensive Income should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT FINANCIAL POSITION

	Notes	2024 $'000	2023 (restated) $'000	1 July 2022 (restated) $'000
ASSETS				
Current Assets				
Cash and cash equivalents	5	**14,332**	77,134	247,012
Trade and other receivables	6	**35,209**	28,797	30,467
Prepayments	7	**6,064**	6,303	12,854
Inventory	8	**2,044**	2,182	841
Total Current Assets		**57,649**	114,416	291,174
NON-CURRENT ASSETS				
Other financial assets	20	**718**	1,131	484
Contract asset	2	**2,069**	2,323	2,062
Property, plant and equipment	10	**346,320**	380,375	59,232
Intangible assets	11	**466**	967	1,360
Right-of-use assets	16	**1,380**	7,448	7,520
Exploration and evaluation assets	12	**193,805**	184,569	164,909
Gas and oil assets	13	**475,152**	535,842	595,347
Deferred tax asset	3	**83,818**	84,733	64,530
Deferred petroleum resource rent tax asset	3	**61,809**	53,167	39,685
Total Non-Current Assets		**1,165,537**	1,250,555	935,129
Exploration assets classified as held for sale		**-**	-	1,558
Total Assets		**1,223,186**	1,364,971	1,227,861
LIABILITIES				
Current Liabilities				
Trade and other payables	9	**76,773**	68,679	32,752
Provisions	15	**32,920**	166,098	29,867
Lease liabilities	16	**847**	1,467	1,251
Interest bearing loans and borrowings		**-**	-	37,000
Total Current Liabilities		**110,540**	236,244	100,870
NON-CURRENT LIABILITIES				
Trade and other payables	9	**-**	19,262	-
Provisions	15	**433,720**	417,509	446,754
Lease liabilities	16	**927**	9,182	9,612
Interest bearing loans and borrowings	17	**253,147**	143,956	121,000
Other financial liabilities	20	**2,830**	2,853	3,285
Deferred petroleum resource rent tax liability	3	**4,376**	7,479	23,365
Total Non-Current Liabilities		**695,000**	600,241	604,016
Liabilities directly associated with assets held for sale		**-**	-	908
Total Liabilities		**805,540**	836,485	705,794
Net Assets		**417,646**	528,486	522,067
EQUITY				
Contributed equity	19	**718,881**	716,726	478,261
Reserves	19	**27,185**	26,071	197,625
Accumulated losses		**(328,420)**	(214,311)	(153,819)
Total Equity		**417,646**	528,486	522,067

The above Consolidated Statement of Financial Position should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Notes	Issued Capital $'000	Reserves $'000	Accumulated Losses $'000	Total Equity $'000
Balance at 1 July 2023 (restated)		**716,726**	**26,071**	**(214,311)**	**528,486**
Loss for the period		**-**	**-**	**(114,109)**	**(114,109)**
Other comprehensive expenditure		**-**	**(412)**	**-**	**(412)**
Total comprehensive loss for the period		**-**	**(412)**	**(114,109)**	**(114,521)**
Transactions with owners in their capacity as owners:					
Share based payments	19	**-**	**3,681**	**-**	**3,681**
Transferred to issued capital	19	**2,155**	**(2,155)**	**-**	**-**
Balance as at 30 June 2024		**718,881**	**27,185**	**(328,420)**	**417,646**
Balance at 1 July 2022		478,261	197,625	(177,461)	498,425
Impact of adoption of amendments to AASB 112 (page 103)		-	-	23,642	23,642
Balance at 1 July 2022 (restated)		478,261	197,625	(153,819)	522,067
Loss for the period (restated)		-	-	(60,492)	(60,492)
Other comprehensive expenditure		-	648	-	648
Total comprehensive gain/(loss) for the period (restated)		-	648	(60,492)	(59,844)
Transactions with owners in their capacity as owners:					
Equity issue	19	58,596	-	-	58,596
Share based payments	19	-	7,667	-	7,667
Transferred to retained earnings	19	-	-	-	-
Transferred to issued capital	19	179,869	(179,869)	-	-
Balance as at 30 June 2023 (restated)		716,726	26,071	(214,311)	528,486

The above Consolidated Statement of Changes in Equity should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Notes	2024 $'000	2023 $'000
CASH FLOWS FROM OPERATING ACTIVITIES			
Receipts from customers		**214,079**	198,265
Payments to suppliers and employees		**(92,844)**	(101,632)
Payments for restoration		**(207,723)**	(19,580)
Petroleum resource rent tax refund/(paid)		**195**	(6,225)
Interest received		**3,603**	2,910
Interest paid		**(17,073)**	(10,974)
Net cash from operating activities	5	**(99,763)**	62,764
CASH FLOWS FROM INVESTING ACTIVITIES			
Payments for property, plant and equipment		**(46,846)**	(245,370)
Payments for intangibles		**(34)**	(1,092)
Payments for exploration and evaluation		**(15,045)**	(23,248)
Payments for gas and oil assets		**(4,555)**	(5,858)
Proceeds from held for sale assets		**-**	650
Net cash flows used in investing activities		**(66,480)**	(274,918)
CASH FLOWS FROM FINANCING ACTIVITIES			
Repayment of principal portion of lease liabilities		**(1,457)**	(1,262)
Proceeds from equity issue		**-**	57,579
Proceeds from borrowings	5	**107,000**	158,000
Repayment of borrowings	5	**-**	(158,000)
Transaction costs associated with borrowings	5	**-**	(15,142)
Net cash flow from financing activities		**105,543**	41,175
Net (decrease)/increase in cash held		**(60,700)**	(170,979)
Net foreign exchange differences		**(2,102)**	1,101
Cash and cash equivalents at 1 July		**77,134**	247,012
Cash and cash equivalents at 30 June	5	**14,332**	77,134

The above Consolidated Statement of Cash Flows should be read in conjunction with the accompanying notes.

COOPER ENERGY

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

CORPORATE INFORMATION

The consolidated financial report of Cooper Energy Limited and its controlled entities ("Cooper Energy", "the Group", or "the Company"), for the year ended 30 June 2024, was authorised for issue on 27 August 2024 in accordance with a resolution of the Directors.

Cooper Energy Limited is a for profit company limited by shares, incorporated and domiciled in Australia, and whose shares are publicly traded on the Australian Securities Exchange.

The nature of the operations and principal activities of the Group are described in the Directors' Statutory Report and Note 1.

BASIS OF PREPARATION

The financial report is a general-purpose financial report, which has been prepared in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board ("AASB") and International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board.

The financial report has also been prepared on a historical cost basis, except for equity instruments measured at fair value through other comprehensive income and other items as set out in the notes indicated as measured at fair value through profit and loss.

The financial report is presented in Australian dollars. Under the option available to the Group under ASIC Corporations (Rounding in Financial/Directors' Reports) Instrument 2016/191, all values are rounded to the nearest thousand dollars ($'000), unless otherwise stated. Australian dollars is the functional currency of Cooper Energy Limited and all of its subsidiaries. Transactions in foreign currencies are initially recorded in the functional currency of the transacting entity at the exchange rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies at the reporting date are translated at the rates of exchange prevailing at that date. Exchange differences in the consolidated financial statements are taken to the income statement.

Funding overview

The Group holds cash balances of $14.3 million and has drawn debt of $265.0 million as at the end of the reporting period with a further $135.0 million committed, available and undrawn as at 30 June 2024, under a senior secured reserve based loan facility with an expected maturity date of September 2027. The Company also has a further $12.6 million availability under the Company's working capital facility. All debt covenants have been complied with to the date of this report.

GOING CONCERN BASIS

The consolidated financial statements have been prepared on the basis that the Group is a going concern, which contemplates continuity of normal operations and the realisation of assets and settlement of liabilities in the ordinary course of business. The directors have formed the view that there are reasonable grounds to believe that the Group will continue as a going concern.

BASIS OF CONSOLIDATION

The consolidated financial statements are those of the consolidated entity, comprising Cooper Energy Limited ("the parent entity") and its controlled entities ("Cooper Energy" or "the Group").

The financial statements of subsidiaries are prepared for the same reporting period as the parent entity, using consistent accounting policies. All inter-company balances and transactions, income and expenses and profit and losses arising from intra-group transactions, have been eliminated in full. Subsidiaries are consolidated from the date on which the Group gains control of the subsidiary and cease to be consolidated from the date on which the Group ceases to control the subsidiary.

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

In the process of applying the Group's accounting policies, management is required to make judgements, estimates and assumptions that affect the reported amounts in the financial statements. Judgements, estimates and assumptions which are material to specific notes of the financial statements are below:

Note 3	Income tax	Note 16	Leases
Note 13	Gas and oil assets	Note 21	Interests in joint arrangements
Note 14	Impairment	Note 26	Share based payments
Note 15	Provisions		

Judgements, estimates and assumptions which are material to the overall financial statements are below:

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

Determination of recoverable hydrocarbons

Estimates of recoverable hydrocarbons impact the asset impairment assessment, depreciation and amortisation rates and decommissioning and restoration provisions.

Estimates of recoverable hydrocarbons are evaluated and reported by qualified petroleum reserves and resources evaluators in accordance with the ASX Listing Rules and definitions and guidelines in the Society of Petroleum Engineers (SPE) 2018 Petroleum Resources Management System (PRMS).

Recoverable hydrocarbon estimates may change, from time to time, if any of the forecast assumptions are revised.

Climate change

In preparing the financial report, management has considered the impact of climate change and current climate-related legislation.

The focus of the Company's strategy on conventional gas production, located close to market in Southeast Australia, is conducive to the supply of lower emissions intensity gas. The Company measures and reports its emissions and emissions offsets to maintain its carbon neutral position as certified by Climate Active, a partnership between the Australian Government and Australian businesses to drive voluntary climate action, whilst also seeking to reduce its gross emissions. These results are published annually in the Company's Sustainability Report and are aligned with the Financial Stability Board's Task Force on Climate-Related Financial Disclosures recommendations on climate-related financial disclosures.

The Company continues to monitor climate-related policy and its impact on the financial report. The current impacts of climate change include estimates of a range of economic and climate-related scenarios. This includes market supply and demand profiles, carbon emissions profiles, legal impacts and technological impacts. These are factored into discount rates, commodity price forecasts, and demand and supply profiles, all of which are impacted by the global demand profile of the economy as a whole. The estimates and forecasts used by the Company are in accordance with current climate-related legislation and policy.

The impact of climate change is considered in the significant judgements and key estimates in a number of areas in the Company's financial report including:

- asset carrying values (exploration and evaluation assets, gas and oil assets) through determination of valuations considered for impairment – refer note 14;
- restoration obligations, including the timing of such activities – refer note 15; and
- deferred taxes, primarily related to asset carrying values and restoration obligations – refer note 3.

The Group continues to monitor climate-related policy and its impact on the Financial Report.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

New standards, interpretations and amendments thereof, adopted by the Group

The Group applied the following amendment to AASB 112 for the first time for the period commencing 1 July 2023: AASB 2021-5 *Amendments to Australian Accounting Standards – Deferred Tax related to Assets and Liabilities arising from a Single Transaction (AASB 112).*

At 1 July 2023 the Group adopted narrow-scope amendments to AASB 112 Income Taxes and have restated comparative periods in accordance with the transition requirements.

Under AASB 112, a deferred tax liability is recognised for all taxable temporary differences and a deferred tax asset is recognised for all deductible temporary differences (to the extent it is probable that taxable profit will be available, against which the deductible temporary difference can be utilised), unless there is an exemption in AASB 112. One of these circumstances, known as the initial recognition exemption, applies when a transaction affects neither accounting profit nor taxable profit, and is not a business combination. The scope of this exemption has now been narrowed, such that it no longer applies, on initial recognition of an asset and liability in a single transaction that gives rise to equal taxable and deductible temporary differences.

The Group's previous accounting policy applied this initial recognition exemption, where the initial recognition of an asset and liability from a single transaction gave rise to equal taxable and deductible temporary differences. The most significant impact of implementing this new amendment comes from temporary differences arising from the Group's restoration provisions and corresponding amounts recognised as part of the cost of the related asset. Adjustments to deferred tax assets and liabilities arising from this amendment have been recognised as at 1 July 2022, being the beginning of the earliest comparative period presented in the financial statements for the year ended 30 June 2024, with the cumulative effect recognised as an adjustment to accumulated losses at that date.

For the year ended 30 June 2024

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

On initial adoption of the standard as at 1 July 2023, the impacts of the transition are the following:

Impact on the Consolidated Statement of Financial Position as at 1 July 2022

	1 July 2022 (Previously reported) $'000	Impact of AASB 112 amendments $'000	1 July 2022 (Restated) $'000
Assets: Deferred tax asset	63,563	967	64,530
Assets: Deferred petroleum resource rent tax asset	12,763	26,922	39,685
Liabilities: Deferred petroleum resource rent tax liability	(19,118)	(4,247)	(23,365)
Equity: Accumulated losses	(177,461)	23,642	(153,819)

Impact on the comparative reporting date is as follows:

	30 June 2023 (Previously reported) $'000	Impact of AASB 112 amendments $'000	30 June 2023 (Restated) $'000
Consolidated Statement of Financial Position			
Assets: Deferred tax asset	92,642	(7,909)	84,733
Assets: Deferred petroleum resource rent tax asset	24,659	28,508	53,167
Liabilities: Deferred petroleum resource rent tax liability	(18,494)	11,015	(7,479)
Equity: Accumulated losses	(245,924)	31,613	(214,311)
Consolidated Statement of Comprehensive Income			
Income tax benefit	28,063	(8,878)	19,185
Petroleum resource rent tax benefit	8,167	16,849	25,016
Basic loss per share	(2.6)	-	(2.3)
Diluted loss per share	(2.6)	-	(2.3)

There was no material impact on the Consolidated Statement of Cash Flows and other comprehensive income.

NOTES TO THE FINANCIAL STATEMENTS

The notes include information which is required to understand the financial statements and is material and relevant to the operations, financial position and performance of the Group. They include applicable accounting policies applied and significant judgements, estimates and assumptions made. Specific accounting policies are disclosed in the respective notes to the financial statements. The notes are organised into the following sections:

Group performance	Provides additional information regarding financial statement lines that are most relevant to explaining the Group's operating performance during the period.
Working capital	Provides additional information regarding financial statement lines that are most relevant to explaining the working capital assets used to contribute to generating the Group's operating performance during the period.
Capital employed	Provides additional information regarding financial statement lines that are most relevant to explaining the capital investments made that contribute to the ability for the Group to generate its operating result during the period and liabilities incurred as a result.
Funding and risk management	Provides additional information regarding financial statement lines that are most relevant to explaining the Group's funding sources. This section also provides information relating to the Group's exposure to various financial risks, its impact on the financial position and performance of the Group and how these risks are managed.
Group structure	Summarises how the group structure affects the financial position and performance of the Group as a whole.
Other information	Includes other information that is disclosed to comply with relevant accounting standards and other pronouncements, but is not directly related to the individual line items in the financial statement.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

GROUP PERFORMANCE

1. SEGMENT REPORTING

Identification of reportable segments and types of activities

The Group has identified its reportable segments to be Southeast Australia, Cooper Basin (both based on the nature and geographic location of its assets) and Corporate and Other. This forms the basis of internal Group reporting to the CEO & Managing Director who is the chief operating decision maker for the purpose of assessing performance and allocating resources between each segment. Revenue and expenses are allocated by way of their natural expense and income category. Other prospective opportunities are also considered from time to time and, if they are secured, will then be attributed to the segment where they are located, or a new segment will be established.

The following are reportable segments:

Southeast Australia
The Southeast Australia segment primarily consists of the operated Sole producing gas assets and the OGPP, the operated Casino Henry producing gas assets and the operated Athena Gas Plant. Revenue is derived from the sale of gas and condensate to six contracted customers and via spot sales. The segment also includes exploration and evaluation and care and maintenance activities ongoing in the Gippsland and Otway basins.

Cooper Basin
This segment comprises production and sale of crude oil in the Group's permits within the Cooper Basin, along with exploration and evaluation of additional oil targets. Revenue is derived from the sale of crude oil to Santos Limited and Beach Energy (Operations) Limited, the two participants in the South Australia Cooper Basin joint venture.

Corporate and Other
The Corporate residual component includes the revenue and costs associated with the running of the business and includes items which are not directly allocable to the other segments.

Accounting policies and inter-segment transactions

The accounting policies used by the Group in reporting segments internally is the same as those contained in the financial statements.

	Southeast Australia $'000	Cooper Basin $'000	Corporate and Other $'000	Consolidated $'000
30 June 2024				
Revenue from gas and oil sales to external customers	**199,142**	**19,905**	**-**	**219,047**
Total revenue	**199,142**	**19,905**	**-**	**219,047**
Segment result before interest, tax, depreciation, amortisation and restoration, exploration and evaluation expense and impairment	**102,049**	**11,300**	**(16,198)**	**97,151**
Restoration expense	**(86,790)**	**-**	**-**	**(86,790)**
Depreciation and amortisation	**(92,837)**	**(3,601)**	**(2,361)**	**(98,799)**
Exploration and evaluation expense	**(1,605)**	**(2,047)**	**-**	**(3,652)**
Impairment	**(269)**	**-**	**-**	**(269)**
Net finance costs	**(17,407)**	**(248)**	**(15,080)**	**(32,735)**
Profit/(loss) before tax	**(96,859)**	**5,404**	**(33,639)**	**(125,094)**
Income tax expense	**-**	**-**	**(915)**	**(915)**
Petroleum resource rent tax benefit	**11,900**	**-**	**-**	**11,900**
Net profit/(loss) after tax	**(84,959)**	**5,404**	**(34,554)**	**(114,109)**
Segment assets	**467,825**	**32,263**	**723,098**	**1,223,186**
Segment liabilities	**707,559**	**4,634**	**93,347**	**805,540**
Additions of non-current assets[1]				
Exploration and evaluation assets	**11,318**	**3,002**	**-**	**14,320**
Gas and oil assets	**(6,508)**	**2,869**	**-**	**(3,639)**
Property, plant and equipment	**4,379**	**-**	**354**	**4,733**
Intangibles	**-**	**-**	**482**	**482**
Total additions of non-current assets	**9,189**	**5,871**	**836**	**15,896**

[1]Additions include the movement in the restoration assets

1. SEGMENT REPORTING CONTINUED

	Southeast Australia $'000	Cooper Basin $'000	Corporate and Other $'000	Consolidated $'000
30 June 2023 (restated)[1]				
Revenue from gas and oil sales to external customers	184,542	12,343	-	196,885
Total revenue	184,542	12,343	-	196,885
Segment result before interest, tax, depreciation, amortisation and restoration, exploration and evaluation expense and impairment	113,656	6,484	(27,071)	93,069
Restoration expense	(46,343)	-	-	(46,343)
Depreciation and amortisation	(93,450)	(2,066)	(3,308)	(98,824)
Impairment	(26,118)	-	-	(26,118)
Net finance costs	(18,764)	(160)	(7,553)	(26,477)
Profit/(loss) before tax	(71,019)	4,258	(37,932)	(104,693)
Income tax benefit	-	-	19,185	19,185
Petroleum resource rent tax benefit	25,016	-	-	25,016
Net profit/(loss) after tax (restated)	(46,003)	4,258	(18,747)	(60,492)
Segment assets	608,133	27,470	729,368	1,364,971
Segment liabilities	665,317	5,244	165,924	836,485
Additions of non-current assets[2]				
Exploration and evaluation assets	23,835	986	-	24,821
Gas and oil assets	10,981	3,181	-	14,162
Property, plant and equipment	(9,765)	-	402	(9,363)
Intangibles	-	-	1,092	1,092
Total additions of non-current assets	25,051	4,167	1,494	30,712

[1] Comparative information has been restated to reflect the adoption of narrow scope amendments to AASB 112 Income Taxes, refer to page 103 for details
[2] Additions include the movement in the restoration assets

In 2024, contracted revenue from three customers amounted to $79.0 million, $42.5 million and $21.7 million respectively in the Southeast Australia segment. In 2023, contracted revenue from three customers amounted to $88.6 million, $43.4 million and $22.0 million respectively in the Southeast Australia segment.

For the year ended 30 June 2024

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

2. REVENUES AND EXPENSES

REVENUES

Revenue from gas and oil sales

	Notes	2024 $'000	2023 $'000
Revenue from contracts with customers			
Gas revenue from contracts with customers		**199,154**	184,542
Oil revenue from contracts with customers		**19,893**	12,403
Total revenue from contracts with customers		**219,047**	196,945
Other revenue			
Fair value movement on crude oil receivables		**-**	(60)
Total other revenue		**-**	(60)
Total revenue from gas and oil sales		**219,047**	196,885
Other income			
Lease adjustment		**2,614**	-
Other income		**741**	-
Total other income		**3,355**	-

Contract assets related to contracts with customers

The Group has recognised the following assets related to contracts with customers.

	2024	2023
Opening balance	**2,323**	2,062
Contract assets recognised during the year	**-**	492
Unwind of contract asset	**(254)**	(231)
Closing balance	**2,069**	2,323

EXPENSES

	Notes	2024	2023
Cost of sales			
Production expenses		**(59,212)**	(61,081)
Royalties		**(1,558)**	(1,118)
Third-party product purchases and trading costs		**(9,389)**	(7,604)
Amortisation of gas and oil assets		**(58,214)**	(58,654)
Depreciation of property, plant and equipment		**(38,043)**	(36,853)
Inventory movement		**(905)**	931
Total cost of sales		**(167,321)**	(164,379)
Other expenses			
Selling expense		**(1,100)**	(402)
General administration		**(14,472)**	(19,063)
Depreciation of property, plant and equipment		**(745)**	(713)
Amortisation of intangibles		**(534)**	(1,485)
Depreciation of right-of-use assets		**(1,263)**	(1,119)
Care and maintenance		**(8,102)**	(2,612)
Restoration expense		**(86,790)**	(46,343)
Exploration and evaluation expense		**(3,652)**	-
Impairment expense	14	**(269)**	(26,118)
Expected credit losses of trade and other receivables	20	**(23,546)**	(2,815)
Other (including new ventures)		**(6,967)**	(9,606)
OGPP reconfiguration and commissioning works		**-**	(446)
Total other expenses		**(147,440)**	(110,722)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

2. REVENUES AND EXPENSES CONTINUED

Employee benefits expense included in general administration	2024 $'000	2023 $'000
Director and employee benefits	**(37,246)**	(28,960)
Share based payments	**(3,681)**	(7,667)
Superannuation expense	**(2,823)**	(2,365)
Total employee benefits expense (gross)	**(43,750)**	(38,992)

The increase in employee benefits in 2024, compared to 2023, is largely due to a full year's recognition of the employee costs at the Orbost Gas Processing Plant; Cooper Energy took over operatorship of the plant on 22 May 2023.

ACCOUNTING POLICY

Revenue from contracts with customers

Revenue from contracts with customers is recognised at the point in time when control of the natural gas, liquids or crude oil is transferred to the customer, at an amount that reflects the consideration to which the Group expects to be entitled in exchange for those goods. This is generally when the product is transferred to the delivery point specified in the individual customer contract. The Group's performance obligations are considered to relate only to the sale of the natural gas, liquids or crude oil, with each GJ of natural gas or barrel of liquids or crude oil considered to be a separate performance obligation under the contractual arrangements in place.

The Group has concluded that it is the principal in all of its revenue arrangements since it controls the goods before transferring them to the customer. Under the terms of the relevant joint operating arrangements, the Group is entitled to its participating share in the natural gas, liquids or crude oil, based on the Group's entitlement interest. Revenue from contracts with customers is recognised based on the actual volumes sold to customers.

The Group's sales of natural gas are predominantly based on contracted prices, while crude oil and liquids transactions are priced based on crude oil market prices, adjusted for a quality differential.

In the prior period, crude oil sales contained provisional pricing. Revenue from contracts with customers was recognised based on the provisional pricing at the date of delivery, with the price estimate based on the forward curve. The difference between the estimated price and the price ultimately achieved for the sale of the crude oil transaction was recognised as a movement in the fair value of the receivable in accordance with AASB 9 Financial Instruments. This amount is presented as other revenue in Note 2 as these movements are not within the scope of AASB 15 Revenue from Contracts with Customers.

Contract assets

A contract asset is recognised for gas contracts that have variable selling prices, which are allocated proportionately to all the performance obligations over the life of the contract. Contract assets unwind as "revenue from contracts with customers" with reference to the performance obligation over the life of the contract.

For the year ended 30 June 2024

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

3. INCOME TAX

	2024 $'000	2023 (restated) $'000
Consolidated Statement of Comprehensive Income		
Current income tax		
Current year	**-**	-
	-	-
Deferred income tax		
Origination and reversal of temporary differences	**(66,835)**	7,814
Recognition of tax losses	**65,920**	11,371
	(915)	19,185
Income tax (expense)/benefit	**(915)**	19,185
Current petroleum resource rent tax		
Current year	**155**	(4,184)
	155	(4,184)
Deferred petroleum resource rent tax		
Origination and reversal of temporary differences	**11,745**	29,200
	11,745	29,200
Petroleum resource rent tax benefit	**11,900**	25,016
Total tax benefit	**10,985**	44,201
Reconciliation between tax expense and pre-tax net profit		
Accounting loss before tax from continuing operations	**(125,094)**	(104,693)
Income tax based on the domestic corporation tax rate of 30% (2023: 30%)	**37,528**	31,408
(Increase)/decrease in income tax expense due to:		
Non-deductible expenditure	**(1,478)**	(2,744)
Recognition of royalty related income tax benefits	**(3,512)**	(9,575)
Derecognition of deferred tax asset	**(33,285)**	-
Other	**(168)**	96
Income tax benefit	**(915)**	19,185
Petroleum resource rent tax benefit	**11,900**	25,016
Total tax benefit	**10,985**	44,201

TAX CONSOLIDATION

Cooper Energy Limited and its 100% owned Australian resident subsidiaries are consolidated for Australian income tax purposes, with Cooper Energy Limited being the head entity of the tax consolidated group. Members of the Group entered into a tax sharing arrangement in order to allocate income tax expense to the wholly-owned subsidiaries. In addition, the agreement provides for the allocation of income tax liabilities between the entities should the head entity default on its tax payment obligations.

Members of the tax consolidated group have entered into a tax funding agreement. The tax funding agreement requires members of the tax consolidated group to make contributions to the head company for tax liabilities and deferred tax balances arising from transactions occurring after the implementation of tax consolidation. Contributions are payable following the payment of the liabilities by Cooper Energy Limited. The assets and liabilities arising under the tax funding agreement are recognised as inter-company assets and liabilities with a consequential adjustment to income tax expense or benefit. In addition, the agreement provides for the allocation of income tax liabilities between the entities should the head entity default on its tax payment obligations or upon leaving the Group. The current and deferred tax amounts are measured in a systematic manner that is consistent with the broad principles in AASB 112 *Income Taxes*.

UNRECOGNISED TEMPORARY DIFFERENCES

At 30 June 2024, there are no unrecognised temporary differences associated with the Group's investments in subsidiaries, as the Group has no liability for additional taxation should unremitted earnings be remitted (2023: $nil).

For the year ended 30 June 2024

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

3. INCOME TAX CONTINUED

FRANKING TAX CREDITS

At 30 June 2024 the parent entity had franking tax credits of $42.9 million (2023: $42.9 million). The fully franked dividend equivalent is $142.9 million (2023: $142.9 million).

PETROLEUM RESOURCE RENT TAX

Cooper Energy Limited has recognised a deferred tax asset for PRRT of $61.8 million (2023 restated: $53.2 million) and a deferred tax liability for PRRT of $4.4 million (2023 restated: $7.5 million).

INCOME TAX LOSSES

(a) Revenue Losses
A deferred tax asset has been recognised for the year ended 30 June 2024 of $161.6 million (2023: $96.2 million).

(b) Capital Losses
Cooper Energy has not recognised a deferred tax asset for Australian income tax capital losses of $15.5 million (2023: $15.5 million) on the basis that it is not probable that the carried forward capital losses will be utilised against future assessable capital profits.

	Consolidated Statement of Financial Position		Consolidated Statement of Comprehensive Income	
	2024 $'000	2023 (restated) $'000	2024 $'000	2023 (restated) $'000
Deferred corporate income tax				
Deferred income tax at 30 June relates to:				
Deferred tax liabilities				
Trade and other receivables	**21**	57	**(36)**	(5,937)
Gas and oil assets	**90,321**	97,773	**(7,452)**	(3,188)
Exploration and evaluation	**53,069**	48,640	**4,429**	6,436
Property, plant and equipment	**36,845**	32,440	**4,405**	24,203
Other	**18,083**	16,469	**1,614**	13,594
	198,339	195,379	**2,960**	35,108
Deferred tax assets				
Leases	**532**	3,195	**(2,663)**	(64)
Provisions	**117,252**	178,290	**(61,038)**	30,575
Tax losses	**161,577**	96,205	**65,372**	19,610
Other	**2,796**	2,422	**374**	4,172
	282,157	280,112	**2,045**	54,293
Deferred tax (expense) / benefit			**(915)**	19,185
Deferred tax asset from corporate tax	**83,818**	84,733		
Deferred tax from PRRT				
Deferred PRRT at 30 June relates to:				
Deferred tax liabilities				
Gas and oil assets	**4,376**	7,479	**(3,103)**	(7,392)
Deferred tax liability from PRRT	**4,376**	7,479		
Deferred tax assets				
Gas and oil assets	**61,809**	53,167	**8,642**	13,482
Deferred tax asset from PRRT	**61,809**	53,167		
Total PRRT deferred tax benefit			**5,539**	6,090

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

3. INCOME TAX CONTINUED

ACCOUNTING POLICY

Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and tax laws that are enacted, or substantively enacted, by the reporting date.

Deferred tax is recognised on all temporary differences, except for:

- when deferred tax arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss and does not give rise to equal taxable and deductible temporary differences; and
- the taxable temporary difference is associated with investments in subsidiaries, associates or interests in joint ventures, and the timing of the reversal of the temporary difference can be controlled and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets are recognised for all deductible temporary differences, carry-forward of unused tax assets and unused tax losses, to the extent that it is probable that future taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilised.

The carrying amount of deferred income tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilised. Unrecognised deferred income tax assets are reassessed at each reporting date and are recognised to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Deferred income tax assets and liabilities are measured at the tax rates that were expected to apply to the year when the asset is realised or the liability is settled, based on tax rates and tax laws that have been enacted or substantively enacted by the reporting date.

Income taxes relating to items recognised directly in equity are recognised in equity and not in profit or loss.

Deferred tax assets and deferred tax liabilities are offset only if a legally enforceable right exists to offset current tax assets against current tax liabilities and the deferred tax asset and liabilities relate to the same taxable entity and the same taxation authority.

Petroleum Resource Rent Tax

For PRRT purposes, the impact of future augmentation on expenditure is included in the determination of future taxable profits when assessing the extent to which a deferred tax asset can be recognised in the statement of financial position. Deferred tax assets are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

Goods and Services Taxes (“GST”)

Revenues, expenses and assets are recognised net of the amount of GST. Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the Consolidated Statement of Financial Position. Commitments and contingencies are disclosed net of the amount of GST recoverable from, or payable to, the taxation authority.

Cash flows are included in the Cash Flow Statement on a net basis and the net GST component of cash flows arising from investing and financing activities, which is recoverable from, or payable to, the taxation authority, are classified as operating cash flows.

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The Group has a Tax Risk Management Framework which outlines how the direct and indirect tax obligations of Cooper Energy Limited are met from an operational, governance and tax risk management perspective.

Management judgements are made in relation to the types of arrangements considered to be a tax on income, including PRRT, in contrast to an operating cost.

Judgement is also made in assessing whether deferred tax assets and certain deferred tax liabilities are recognised on the Consolidated Statement of Financial Position. Deferred tax assets, including those arising from un-recouped tax losses, capital losses, and temporary differences arising from the PRRT legislation, are recognised only where it is considered more probable they will be recovered, which is dependent on the generation of sufficient future taxable profits. Future taxable profits are estimated by using Board approved internal budgets and forecasts.

Judgements are also required about the application of income tax legislation. These judgements and assumptions are subject to risk and uncertainty, hence there is a possibility changes in circumstances will alter expectation, which may impact the amount of deferred tax assets and deferred tax liabilities recognised on the Consolidated Statement of Financial Position and the amount of other tax losses and temporary differences not yet recognised.

In such circumstances, some or all of the carrying amounts of recognised deferred tax assets and liabilities may require adjustment, resulting in a corresponding credit or charge to the Consolidated Statement of Comprehensive Income.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

4. EARNINGS PER SHARE

The following reflects the net loss and share data used in the calculations of earnings per share:

	2024 $'000	2023 (restated) $'000
Net loss after tax attributable to shareholders	**(114,109)**	(60,492)

	2024 Thousands	2023 Thousands
Weighted average number of ordinary shares used in calculating basic earnings per share	**2,636,076**	2,621,292
Dilutive performance rights and share appreciation rights[1]	**-**	-
Weighted average number of ordinary shares used in calculating dilutive earnings per share	**2,636,076**	2,621,292
Basic loss per share for the period (cents per share)	**(4.3)**	(2.3)
Diluted loss per share for the period (cents per share)	**(4.3)**	(2.3)

[1] The weighted average number of potentially dilutive shares at 30 June 2024 is 47.3 million (2023: 28.9 million)

At 30 June 2024 there exist performance rights and share appreciation rights that if vested, would result in the issue of additional ordinary shares over the next three years. In the current period, these potential ordinary shares are considered antidilutive as their conversion to ordinary shares would reduce the loss per share. Accordingly, they have been excluded from the dilutive earnings per share calculation. There have been no other transactions involving ordinary shares, or potential ordinary shares, between the reporting date and the date of completion of these financial statements.

ACCOUNTING POLICY

Basic earnings per share are calculated as net profit attributable to shareholders divided by the weighted average number of ordinary shares. Diluted earnings per share is calculated as net profit attributable to shareholders divided by the weighted average number of ordinary shares and dilutive potential ordinary shares.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

WORKING CAPITAL

5. CASH AND CASH EQUIVALENTS AND TERM DEPOSITS

	2024 $'000	2023 (restated) $'000
Current Assets		
Cash at bank and in hand	**14,332**	77,134
Cash and cash equivalents	**14,332**	77,134

Reconciliation of net profit to net cash flows from operating activities

	2024 $'000	2023 $'000
Net loss after tax	**(114,109)**	(60,492)
Add/(deduct) non-cash items:		
Amortisation of gas and oil assets	**58,214**	58,654
Depreciation of property, plant and equipment	**38,788**	37,566
Amortisation of intangibles	**534**	1,485
Depreciation of right-of-use assets	**1,263**	1,119
Impairment expense	**269**	26,118
Exploration and evaluation expense	**3,652**	-
Restoration (income)/expense	**86,790**	46,343
Share based payments	**3,681**	7,667
Finance costs	**19,174**	16,850
Foreign exchange (gain)/loss	**2,102**	(705)
Other non-cash movements	**23,408**	(532)
Net cash from operating activities before changes in assets or liabilities	**123,766**	134,073
Add/(deduct) changes in operating assets or liabilities:		
Increase in trade and other receivables	**(29,707)**	(1,406)
Decrease/(increase) in inventories	**138**	(1,340)
(Increase)/decrease in prepayments	**(305)**	6,527
Increase in deferred taxes	**(10,830)**	(45,527)
Increase/(decrease) in trade and other payables	**29,778**	(6,331)
Decrease in provisions	**(212,603)**	(23,232)
Net cash from operating activities	**(99,763)**	62,764

Reconciliation of liabilities arising from financing activities

	Borrowings		Lease Liabilities	
	2024 $'000	2023 $'000	2024 $'000	2023 $'000
Balance at beginning of period	**143,956**	158,000	**10,649**	10,863
Financing cash flows[1]	**107,000**	(15,142)	**(1,457)**	(1,262)
Other	**2,191**	1,098	**(7,418)**	1,048
Balance at end of period	**253,147**	143,956	**1,774**	10,649

[1] Financing cash flows consist of: for borrowings, the net amount of proceeds from borrowings and transaction costs associated with borrowings, and for lease liabilities, repayment of lease liabilities in the statement of cash flows.

ACCOUNTING POLICY

Cash and cash equivalents in the Consolidated Statement of Financial Position comprise cash at bank and short-term deposits for periods of up to three months or subject to insignificant changes in value. For the purposes of the Statement of Cash Flows, cash and cash equivalents includes cash and term deposits as defined above, net of outstanding bank overdrafts.

Cash held in escrow with associated restrictions, whereby the Group cannot use that cash for operational purposes as it deems appropriate, is not included in cash and cash equivalents.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

6. TRADE AND OTHER RECEIVABLES

	2024 $'000	2023 $'000
Current Assets		
Trade and other receivables	**13,243**	11,360
Accrued revenue	**21,895**	17,247
Interest receivable	**71**	190
	35,209	28,797

Expected credit losses in respect of trade and other receivables is set out in Note 20.

ACCOUNTING POLICY

Trade receivables are non-interest bearing and generally have an average of 35 day terms. Trade receivables are initially recognised at the transaction price as defined by AASB 15 Revenue from Contracts with Customers and subsequently carried at amortised cost less any allowances for expected credit loss. An allowance for expected credit loss is recognised using the simplified approach which permits the use of the lifetime expected loss provision for all trade receivables. Bad debts are written off when identified.

7. PREPAYMENTS

	2024 $'000	2023 $'000
Insurance	**3,752**	4,229
Prepaid cash calls to joint arrangements	**1,747**	1,970
Other prepayments	**565**	104
	6,064	6,303

8. INVENTORY

	2024 $'000	2023 $'000
Petroleum products	**426**	966
Spares and parts	**1,618**	1,216
	2,044	2,182

All inventory items are carried at cost in the current and previous financial years.

ACCOUNTING POLICY

Inventories are carried at the lower of their cost or net realisable value. Inventories held by the Group are in respect of unsold oil and spares and parts involved in drilling operations. Items held as insurance or capital spares are treated as part of property, plant and equipment.

9. TRADE AND OTHER PAYABLES

	2024 $'000	2023 $'000
Current		
Trade payables	**29,531**	6,411
Accruals (capital and operating expenditure)	**27,242**	22,268
Deferred consideration[1]	**20,000**	40,000
	76,773	68,679
Non-Current		
Deferred consideration[1]	**-**	19,262

[1] Deferred consideration represents the fixed payments due 12 and 24 months after the 28 July 2022 financial close of the OGPP acquisition. The Group records deferred consideration at the present value of consideration payments.

ACCOUNTING POLICY

Trade payables are non-interest bearing and carried at amortised cost. The amounts represent liabilities for goods and services provided during the financial year, but not yet settled at the balance sheet date. Accruals represent unbilled goods or services.

CAPITAL EMPLOYED

10. PROPERTY, PLANT AND EQUIPMENT

	Production assets		Corporate assets		Total	
	2024 $'000	2023 $'000	**2024 $'000**	2023 $'000	**2024 $'000**	2023 $'000
Reconciliation of carrying amounts at beginning and end of period:						
Carrying amount at beginning of period	**377,382**	55,928	**2,993**	3,304	**380,375**	59,232
Assets acquired[1]	**-**	374,016	**-**	-	**-**	374,016
Additions	**5,607**	10,724	**354**	402	**5,961**	11,126
Restoration	**(1,228)**	(20,489)	**-**	-	**(1,228)**	(20,489)
Impairment	**-**	(5,944)	**-**	-	**-**	(5,944)
Depreciation	**(38,043)**	(36,853)	**(745)**	(713)	**(38,788)**	(37,566)
Carrying amount at end of period	**343,718**	377,382	**2,602**	2,993	**346,320**	380,375
Cost	**423,996**	419,617	**8,468**	8,114	**432,464**	427,731
Accumulated depreciation	**(80,278)**	(42,235)	**(5,866)**	(5,121)	**(86,144)**	(47,356)
Carrying amount at end of period	**343,718**	377,382	**2,602**	2,993	**346,320**	380,375

[1] The acquisition of OGPP includes $210.0 million of upfront consideration, $58.1 million deferred consideration (discounted at the acquisition date from the undiscounted, or nominal, total of $60.0 million), $27.0 million capitalised acquisition and transaction costs and $78.9 million in relation to the restoration obligations acquired. $40.0 million of the undiscounted deferred consideration was paid in July 2023 (on the 12-month anniversary following the 28 July 2022 financial close) and is included within payments for property, plant and equipment in the Consolidated Statement of Cash Flows.

ACCOUNTING POLICY

Property, plant and equipment comprises office and IT equipment, leasehold improvements, the OGPP and the Athena Gas Plant, and are stated at historical cost less accumulated depreciation and any accumulated impairment losses (refer to Note 14 for a description of the Company's impairment policy). Historical cost includes expenditure that is directly attributable to the acquisition of the items. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. Repairs and maintenance are recognised in the Consolidated Statement of Comprehensive Income, as incurred.

Depreciation on property plant and equipment is calculated at between 7.5% and 37.5% per annum using the diminishing value method over the respective asset's estimated useful live. Production assets are depreciated on a units of production basis. The assets' residual values and useful lives are reviewed and adjusted, if appropriate, at each reporting date.

An item of property, plant and equipment is derecognised upon disposal, or when no further future economic benefits are expected from its use. Any gains or losses arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the net carrying amount of the asset) is included in the Consolidated Statement of Comprehensive Income.

11. INTANGIBLE ASSETS

	2024 $'000	2023 $'000
Reconciliation of carrying amounts at beginning and end of period:		
Carrying amount at beginning of period	**967**	1,360
Additions	**482**	1,092
Disposals	**(449)**	-
Amortisation	**(534)**	(1,485)
Carrying amount at end of period	**466**	967
Cost	**4,427**	4,394
Accumulated amortisation	**(3,961)**	(3,427)
Carrying amount at end of period	**466**	967

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended 30 June 2024

11. INTANGIBLE ASSETS CONTINUED

ACCOUNTING POLICY

Intangible assets comprise software and carbon credits, and are stated at historical cost less accumulated amortisation and any accumulated impairment losses where applicable. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Intangible assets are determined to have a finite useful life and are amortised over their useful lives and tested for impairment whenever there is an indicator of impairment. Amortisation on intangibles is calculated at 20% per annum using the straight line method. The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each reporting date.

12. EXPLORATION AND EVALUATION ASSETS

	Notes	**2024 $'000**	2023 $'000
Reconciliation of carrying amounts at beginning and end of period			
Carrying amount at beginning of period		**184,569**	164,909
Additions[1]		**14,545**	25,088
Restoration		**(225)**	(267)
Impairment	14	**(269)**	(5,161)
Exploration and evaluation expense		**(3,652)**	-
Transfer to gas and oil assets		**(1,163)**	-
Carrying amount at end of period[2]		**193,805**	184,569

[1]Additions in 2024 predominantly relate to PEL 92 exploration drilling and the order of the first subsea tree for the East Coast Supply Project (ECSP). Additions in 2023 relate to ECSP and licensing and interpretation of 3D seismic data in Gippsland Basin.
[2] Recoverability is dependent on the successful development and commercial exploration or sale of the respective areas of interest.

ACCOUNTING POLICY

Exploration and evaluation expenditure include costs incurred in the search for hydrocarbon resources and determining the commercial viability in each identifiable area of interest. Exploration and evaluation expenditure is accounted for in accordance with the successful efforts method and is capitalised to the extent that:

i. the rights to tenure of the areas of interest are current and the Group controls the area of interest in which the expenditure has been incurred; and

ii. such costs are expected to be recouped through successful development and exploration of the area of interest, or alternatively by its sale; or

iii. exploration and evaluation activities in the area of interest have not at the reporting date:

   a. reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves; and

   b. active and significant operations in, or in relation to, the area of interest are continuing.

An area of interest refers to an individual geological area where the potential presence of a natural gas or an oil field is considered favourable or has been proven to exist and, in most cases, comprises an individual prospective gas or oil field.

Exploration and evaluation expenditure which does not satisfy these criteria is written off. Specifically, costs carried forward in respect of an area of interest that is abandoned, or costs relating directly to the drilling of an unsuccessful well, are written off in the year in which the decision to abandon is made, or the results of drilling are concluded. The success or otherwise of a well is determined by reference to the drilling objectives for that well. For successful wells, the well costs remain capitalised on the Consolidated Statement of Financial Position as long as sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. Any appraisal costs relating to determining commercial feasibility are also capitalised as exploration and evaluation assets. A regular review is undertaken of each area of interest to determine the appropriateness of continuing to carry forward costs in relation to that area of interest.

Where facts and circumstances suggest that the carrying amount exceeds the recoverable amount, or where one of the specific factors set out in i-iii above are no longer met, the Group will test for impairment in accordance with the impairment policy stated in Note 14.

Where an ownership interest in an exploration and evaluation asset is exchanged for another, the transaction is recognised by reference to the carrying value of the original interest. Any cash consideration paid, including transaction costs, is accounted for as an acquisition of exploration and evaluation assets. Any cash consideration received, net of transaction costs, is treated as a recoupment of costs previously capitalised with any excess accounted for as a gain on disposal of non-current assets. Where a discovered gas or oil field enters the development phase, the accumulated exploration and evaluation expenditure is tested for impairment and then transferred to gas and oil assets.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

13. GAS AND OIL ASSETS

	Notes	2024 $'000	2023 $'000
Reconciliation of carrying amounts at beginning and end of period:			
Carrying amount at beginning of period		**535,842**	595,347
Additions		**2,932**	4,675
Restoration[1]		**(6,571)**	9,487
Transferred from exploration and evaluation		**1,163**	-
Amortisation		**(58,214)**	(58,654)
Impairment	14	**-**	(15,013)
Carrying amount at end of period		**475,152**	535,842
Cost		**837,422**	839,898
Accumulated amortisation & impairment		**(362,270)**	(304,056)
Carrying amount at end of period		**475,152**	535,842

[1] Updates to restoration provisions have resulted in a reduction in oil and gas assets in 2024

ACCOUNTING POLICY

Gas and oil assets are carried at cost including construction, installation of infrastructure such as roads, pipelines or umbilicals, and the cost of development of wells.

Any restoration assets arising as a result of recognition of a restoration provision are also included in the carrying amount of gas and oil assets. Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. All other repairs and maintenance are charged to the Consolidated Statement of Comprehensive Income as incurred.

Gas and oil assets are amortised on a units-of-production basis, using the latest approved estimate of reserves and future development cost estimates. Amortisation is charged only once production has commenced. No amortisation is charged on areas under development where production has not commenced. Gas and oil assets are subject to impairment testing, refer to Note 14.

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

Estimation of gas and oil asset expenditure

Capitalised gas and oil assets for the construction of major projects or ongoing well construction activities include accruals in relation to the value of work done. These remain estimates until the contractual arrangement is finalised, including any rebates, credits and variations as part of the standard contractual process.

Amortisation of gas and oil assets

The amortisation of gas and oil assets is impacted by management's estimates of reserves and future development costs. Refer to the significant accounting judgements, estimates and assumptions section on page 102-103 in relation to reserves. Future development cost estimates are costs necessary to develop an assets' undeveloped 2P reserves. These costs are subject to changes in technology, regulation and other external factors.

Significant accounting judgements, estimates and assumptions are also made in relation to the impairment of gas and oil assets and recognition of restoration assets, refer to Note 14 and Note 15 respectively.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the year ended 30 June 2024

14. IMPAIRMENT

	2024 $'000	2023 $'000
Exploration and evaluation assets	**269**	5,161
Property, plant & equipment	**-**	5,944
Gas and oil assets	**-**	15,013
Total impairment recognised	**269**	26,118

The impairment losses recognised in the 2024 financial year relate to one of the Group's exploration licences being fully impaired in accordance with AASB 6 *Exploration for and Evaluation of Mineral Resources* (refer also to Note 12).

During the year, the Group's gas and oil assets and property, plant and equipment were assessed for impairment indicators in accordance with AASB 136 *Impairment of Assets*. There were no impairment indicators present, therefore no impairment was recognised.

In the previous financial year, indicators of impairment were present for the Casino Henry Netherby cash generating unit ("CGU"), resulting in a non-cash impairment loss recognised at June 2023.

ACCOUNTING POLICY

The carrying values of non-current assets, including, property, plant and equipment, capitalised exploration and evaluation assets, and gas and oil assets, are assessed for indicators of impairment at each reporting date (every six months). Where indicators of impairment are present, an impairment test is performed.

An impairment loss is recognised for the amount by which the asset or CGU's carrying amount exceeds its recoverable amount. The recoverable amount of a non-current asset or CGU is the higher of value in use ("VIU") and fair value less cost of disposal ("FVLCD"). For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows. In assessing VIU, the estimated future cash flows are discounted to their present value using a pre-tax rate that reflects the risks specific to the asset. Where the recoverable amount is based on FVLCD, a discounted cash flow model is also used and the inputs are consistent with level 3 on the fair value hierarchy. The estimated future cash flows are prepared on a real (no estimates for future inflation) basis and discounted to their present value using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the asset that would be taken into account by an independent market participant.

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

Impairment of exploration and evaluation assets

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the related lease itself or, if not, whether it successfully recovers the related exploration and evaluation asset through sale.

Management is required to make certain estimates and assumptions in applying this policy. Factors which could impact the future recoverability include the level of gas and oil resources, future technological changes which could impact the cost of extraction, future legal changes (including changes to environmental restoration obligations) and changes to commodity prices. These estimates and assumptions may change as new information becomes available. To the extent that capitalised exploration and evaluation expenditure is determined not to be recoverable in the future, this will reduce profits and net assets in the period in which this determination is made.

In addition, exploration and evaluation expenditure is capitalised if activities in the area of interest have not yet reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable gas and oil reserves or resources. To the extent that it is determined in the future that this capitalised expenditure should be written off, this will reduce profits and net assets in the period in which this determination is made.

Impairment of exploration and evaluation assets and gas and oil assets

The Group reviews the carrying amount of gas and oil assets at each reporting date (every six months), starting with an analysis of any indicators of impairment. Where relevant this may involve the preparation of trigger test modelling, for certain CGUs, to determine if any indicators of impairment are present. Where indicators of impairment are present, the Group will test whether the CGU's recoverable amount exceeds its carrying amount, with reference to formal impairment models where discounted cash flow models are used to assess the recoverable amount. Relevant items of working capital and property, plant and equipment are allocated to CGUs when testing for impairment.

The estimated expected cash flows used in the discounted cash flow model are based on management's best estimate of the future production of reserves and sales volumes, commodity prices, foreign exchange rates, development expenditure in order to access the reserves, and operating expenditure. Estimates of future commodity prices are based on the Group's best estimate of future market prices with reference to external brokers, market data and futures prices. Future commodity prices are reviewed at least annually. Where volumes are contracted, future prices are based on the contracted price.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

15. PROVISIONS

	2024 $'000	2023 $'000
Current Liabilities		
Employee benefits	**4,265**	4,547
Restoration provisions	**28,655**	161,551
	32,920	166,098
Non-Current Liabilities		
Employee benefits	**1,207**	763
Restoration provisions	**432,513**	416,746
	433,720	417,509

	2024 $'000	2023 $'000
Movement in carrying amount of the current restoration provision:		
Carrying amount at beginning of period	**161,551**	26,957
Restoration expenditure incurred[1]	**(212,764)**	(25,720)
Changes in provisions[2]	**55,710**	33,600
Transferred from non-current provisions	**24,158**	126,714
Carrying amount at end of period	**28,655**	161,551
Movement in carrying amount of the non-current restoration provision:		
Carrying amount at beginning of period	**416,746**	446,359
Provisions acquired	**-**	78,887
Changes in provisions[2]	**23,055**	1,474
Transferred to current provisions	**(24,158)**	(126,714)
Increase through accretion	**16,870**	16,740
Carrying amount at end of period	**432,513**	416,746

[1] Majority of the expenditure incurred in 2024 relates to the BMG wells decommissioning programme.

[2] Changes in provisions arise from a combination of changes to estimates of the cost to undertake restoration activities, changes to the estimated time periods during which restoration activity is forecast to occur, changes to assumed future rates of inflation to forecast future expected costs and changes to assumed discount rates to discount future expected costs to derive the present value included here within the restoration provision. Changes to estimates of the costs to undertake restoration activities arise from changes to the assumed scope of activity based on current planning for abandonment and remediation work, changes in the regulatory requirements and also arise from the current cost environment which, in some cases, have led to an increase to service costs.

The discount rate used in the calculation of the provisions as at 30 June 2024 ranged from 4.10% to 4.31% (2023: 3.49% to 5.65%) reflecting a risk-free rate that aligns to the timing of restoration obligations. The movement in the risk-free rate reflects the change in Australian and US government bond rates since the last assessment. Inflation rate assumptions applied in the calculation of the provision as at 30 June 2024 ranged from 2.0% to 3.15% (2023: 2.0% to 3.75%).

From 2009 until 2014, Pertamina Hulu Energi Australia Pty Limited ("Pertamina Australia"), a wholly owned subsidiary of PT Pertamina Hulu Energi ("Pertamina"), held a 10% interest in the BMG joint operating and production agreement ("JOA"). In October 2013, Pertamina Australia withdrew from the JOA. A claim against Pertamina was filed by Cooper Energy in the Supreme Court of Victoria (the "Court"), in December 2022, seeking payment of an amount equal to 10% of the costs and expenses of the decommissioning operations incurred and to be incurred, pursuant to Pertamina Australia's obligations under the withdrawal and abandonment provisions of the JOA. Pertamina has been ordered by the Court to file its defence in September 2024.

ACCOUNTING POLICY

Provisions are recognised when the Group has a legal or constructive obligation, as a result of past transactions or other past events, and it is probable that a future sacrifice of economic benefits will be required and that a reliable estimate can be made of the amount of the obligation.

Employee benefits

Liabilities for wages and salaries, including non-monetary benefits and annual leave are recognised in respect of employees' services up to the reporting date and are measured at the amount expected to be paid when the liabilities are settled. Expenses for non-accumulating sick leave are recognised when the leave is taken and are measured at the rates paid or payable.

The provision for long service leave is recognised and measured as the present value of expected future payments to be made, in respect of services provided by employees up to the reporting date, using the projected unit credit method. Consideration is given to expected future wage and salary levels, years of experience of departed employees, and periods of service.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

15. PROVISIONS CONTINUED

Expected future payments are discounted using market yields at the reporting date based on high quality corporate bonds with terms of maturity and currencies that match, as closely as possible, the estimated future cash outflows.

Employees' accumulated long service leave is ascribed to individual employees at the rates payable as and when they become entitled to long service leave.

A provision for bonus is recognised and measured based upon the current wage and salary level and forms part of the employee short term incentive plan. The basis for the bonus relating to Key Management Personnel is set out in the Remuneration Report.

Restoration

The Group records a restoration provision for the present value of its share of the estimated cost to restore its sites. The nature of restoration activities includes the obligations relating to the reclamation, waste site closure, plant closure, production facility removal and other costs associated with the restoration of the site. Risks associated with climate change are factored into forecast timing of restoration activities and will continue to be monitored.

A restoration provision is recognised upon commencement of construction and then reviewed every six months at each reporting date. When the liability is recorded, the carrying amount of the production or exploration asset is increased by the same amount and is depreciated over the remaining producing life of the asset. The movement is recorded as a restoration expense when there is no asset recorded. Over time, the liability is increased for the change in the present value based on a risk-free discount rate and the discount unwind is recorded as an accretion charge within finance costs.

Any changes in the estimate of the provision for restoration arising from changes in the gross cost estimate or changes in the discount rate of the restoration provision are recorded by adjusting the provision and the carrying amount of the production or exploration asset, to the extent that it is appropriate to recognise an asset under accounting standards, and then depreciated over the remaining producing life of the asset. Where it is not appropriate to recognise an asset, changes will immediately be recorded through profit or loss. Any change in assumptions is applied prospectively. These estimated costs are based on current technology available, State, Federal and international legislation, and industry practice.

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

Provisions for restoration costs

Decommissioning and restoration costs are a normal consequence of gas and oil extraction and the majority of this expenditure is incurred at the end of a field's life, many years in the future. In determining an appropriate level of provision, assumptions are made as to the expected future costs to be incurred, the timing of these expected future costs (largely dependent on the life of the field), and the estimated future level of inflation.

The ultimate cost of decommissioning and restoration is uncertain and these costs can vary in response to many factors. These factors include the extent of restoration required due to changes to the relevant legal or regulatory requirements, the emergence of new restoration techniques or experience at other fields, and prevailing service costs.

The expected timing of expenditure can also change, for example in response to changes in gas and oil reserves or to production rates.

Provisions for restoration costs are based on the Company's best estimates based on the information available at the time. Changes to any of the estimates could result in significant changes to the amount of the provision recognised, which would in turn impact future financial results.

The Group's restoration provision includes the following costs:

- for onshore projects, provision has been made for the demolition and removal of all onshore production facilities, removal of contaminated soil, and revegetation of the affected area. Other plant and equipment restoration may include estimates for compensating landowners and the acquisition of land, in line with the requirements of the relevant regulatory authority;
- for offshore assets, provision has been made for the removal of subsea trees and manifolds and removal of flowlines and umbilicals to a certain distance from shore and at a certain depth of water. This includes an assumption that all offshore materials that are constructed using plastics are to be fully removed; and
- offshore pipelines that are constructed from steel and concrete are assumed to remain in-situ, where it can be demonstrated that this will result in a net environmental benefit compared to full removal and where regulatory approval is anticipated to be obtained. Offshore pipelines that are constructed from steel and concrete have previously been accepted by the Australian regulator to be decommissioned in-situ, where it has been demonstrated that this will result in a net environmental benefit, compared to full removal.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

15. PROVISIONS CONTINUED

No assumption is made regarding the potential residual value for the onshore production facilities, nor regarding the potential to repurpose any of the onshore and offshore infrastructure and wells (e.g. potential to convert to gas storage and processing, or for carbon capture and storage).

The Group estimates the future abandonment and restoration costs at different phases in an asset's lifecycle, which in many instances occurs many years into the future. The provisions reflect the Group's best estimate based on current knowledge and information, however further planning and technical analysis of the restoration activities for individual assets will be performed near the end of field life and/or when detailed decommissioning plans are required to be submitted to the relevant regulatory authorities.

Actual abandonment and restoration costs can materially differ from the current estimate as a result of changes in regulations and their application, service costs, site conditions, timing of restoration and changes in removal technology. These uncertainties may result in abandonment and restoration costs differing from amounts included in the provision recognised as at 30 June 2024.

In the event that the removal of all pipelines was required, the Group estimates the additional cost would lead to an increase to the provision of approximately $20.0 - $50.0 million. The Group's provision in respect of the Sole Gas Project is based on estimated cessation of production of the fields and timing of abandonment activities is linked to NOPSEMA's restoration guidance. It is intended that existing infrastructure at Sole will be utilised in a future Manta development. This has not been factored into the provision calculations and would therefore extend the timing of these abandonment activities.

16. LEASES

THE GROUP AS A LESSEE

The Group has lease contracts for properties with remaining lease terms of between 1 month to 6 years and fixed monthly payments. The Group also has certain leases with lease terms of 12 months or less and low value leases.

RIGHT-OF-USE ASSETS

	2024 $'000	2023 $'000
Reconciliation of carrying amounts at beginning and end of period:		
Carrying amount at beginning of period	**7,448**	7,520
Addition	**-**	1,047
Reset[1]	**(4,805)**	-
Depreciation	**(1,263)**	(1,119)
Carrying amount at end of period	**1,380**	7,448
Cost	**7,101**	11,905
Accumulated depreciation	**(5,721)**	(4,457)
Carrying amount at end of period	**1,380**	7,448

[1] Adjustment due to change in lease term of the corporate offices

LEASE LIABILITIES

	2024 $'000	2023 $'000
Reconciliation of carrying amounts at beginning and end of period:		
Carrying amount at beginning of period	**10,649**	10,863
Addition	**-**	1,047
Reset[1]	**(7,418)**	-
Accretion of interest	**523**	495
Payments	**(1,980)**	(1,756)
Carrying amount at end of period	**1,774**	10,649

[1] Adjustment due to change in lease term of the corporate offices

	2024	2023
Current	**847**	1,467
Non-Current	**927**	9,182

For the year ended 30 June 2024

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

16. LEASES CONTINUED

Short-term and low-value lease asset exemptions

For the year ending 30 June 2024, the following expense has been recognised in the Statement of Comprehensive Income for lease arrangements that have been classified as short-term leases or low-value assets.

	2024 $'000	2023 $'000
Short-term leases	**41,441**	9,238
Leases for low-value assets	**28**	176
Total expense recognised	**41,469**	9,414

The Group had total cash outflows for leases of $43.5 million (2023: $11.2 million), inclusive of short-term leases and leases for low-value assets.

ACCOUNTING POLICY

The Group recognises right-of-use assets, and corresponding lease liabilities, at the commencement date of the lease (the date the underlying asset is available for use).

Right-of-use assets are initially measured at a value equal to the respective lease liability, adjusted for any initial direct costs incurred, and lease payments made at or before the commencement date, less any lease incentives received. Subsequently, right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. Property right-of-use assets are depreciated on a straight-line basis over the shorter of estimated useful life and the respective lease term. Right-of-use assets are also allocated to CGUs when testing for impairment (refer to Note 14). Lease liabilities are excluded from the carrying amount of a CGU.

At the commencement date of the lease, the Group recognises lease liabilities measured as the present value of lease payments to be made over the lease term. In calculating the present value of lease payments, the Group uses the incremental borrowing rate at the lease commencement date, if the interest rate implicit in the lease is not readily determinable. Subsequent to initial measurement, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. The carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the fixed lease payments, or a change in the assessment to purchase the underlying asset.

The Group applies the short-term lease recognition exemption to its short-term leases (those leases that have a lease term of 12 months or less, from the commencement date, and do not contain a purchase option). It also applies the lease of low-value assets recognition exemption to leases of office equipment that are considered of low value (below $10,000). Lease payments on short-term leases and leases of low-value assets are recognised as an expense on a straight-line basis over the lease term.

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

Lease term of contracts with renewal options

The Group determines the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease, if the option is reasonably certain to be exercised. The Group has the option, under some of its leases, to lease the assets for additional terms of three to five years. The Group applies judgement in evaluating whether it is reasonably certain to exercise the option to renew. The Group continues to reassess the lease over its term to determine if there is a significant event or change in circumstances that would impact the renewal decision. The Group has included the renewal period as part of the lease term for its property leases, where relevant.

FUNDING AND RISK MANAGEMENT

17. INTEREST BEARING LOANS AND BORROWINGS

	2024 $'000	2023 $'000
Non-current bank debt[1]	**253,147**	143,956

[1] Net of capitalised transaction costs of $11.9 million (2023: $14.0 million).

Cooper Energy has a $400.0 million senior secured reserve-based lending facility, secured across a portfolio of producing assets, and a senior secured $20.0 million working capital facility. It is expected that the facility will be utilised to part fund the planned ECSP project in the Otway Basin. Cooper Energy is in compliance with all covenants at 30 June 2024. A summary of the Group's secured facilities is included below.

Facility	Senior secured reserve based lending facility	Working Capital Facility
Currency	Australian dollars	Australian Dollars
Limit	$400.0 million[1] (2023: $400.0 million)	$20.0 million (2023: $20.0 million)
Utilised amount	$265.0 million (2023: $158.0 million)	$7.4 million[4] (2023: $7.7 million)
Accounting balance	$253.1 million (2023: $144.0 million)	Nil (2023: Nil)
Effective interest rate[2]	9.46% floating	Nil
Maturity[3]	30 September 2027[3]	10 August 2025

[1] As at 30 June 2024, $135.0 million of the facility limit of $400.0 million remains available. Availability of funds under the facility remains subject to an annual redetermination, and a facility reduction schedule commencing in FY25 (reducing to $180.0 million at 30 September 2027).
[2] Effective interest rate is the rate that discounts the estimated future drawdowns and repayments through the expected life of the facility, including the upfront capitalised transaction costs.
[3] Based on the facility reduction schedule, the reserves profile of the borrowing base assets and the facility maturity date.
[4] As at 30 June 2024, no cash amounts have been drawn, $7.4 million has been utilised by way of bank guarantees.

ACCOUNTING POLICY

Borrowings are recognised initially at fair value net of directly attributable transaction costs. Subsequent to initial recognition, borrowings are stated at amortised cost, with any difference between cost and redemption value being recognised in profit or loss over the period of the borrowings on an effective interest basis. Transaction costs are capitalised initially and included in the effective interest rate calculation and unwound over the expected term of the facility.

Borrowings are classified as current liabilities unless the Group has a right to defer the settlement of the liability for at least 12 months after the end of the reporting period. Interest expense is recognised as interest accrues, using the effective interest rate and if not paid at balance date, is reflected in the balance sheet as a payable.

18. NET FINANCE COSTS

	2024 $'000	2023 $'000
Finance Income		
Interest income	**3,484**	3,019
Finance Costs		
Unwind discount on liabilities	**(17,721)**	(17,974)
Finance costs associated with lease liabilities	**(523)**	(495)
Interest expense	**(17,975)**	(11,027)
Total finance costs	**(36,219)**	(29,496)
Net finance costs	**(32,735)**	(26,477)

ACCOUNTING POLICY

Interest earned is recognised in the Consolidated Statement of Comprehensive Income as finance income and is recognised as interest accrues, using the effective interest rate. This is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset. Interest expense is capitalised to the cost of a qualifying asset during the development phase.

19. CONTRIBUTED EQUITY AND RESERVES

For the purposes of Group capital management, capital includes issued capital and all other equity reserves attributable to the equity holders of the parent entity.
The primary objective of the Group's capital management strategy is to maintain an appropriate capital profile to support its business activities and to maximise shareholder value.

At 30 June 2024, the Group has utilised $265.0 million of its reserves based lending facility.
The Group manages its capital structure and makes adjustments in light of economic conditions and within the requirements of financial covenants. To maintain or adjust the capital structure, the Group may adjust its dividend policy, return capital to shareholders, issue new shares or draw on debt. No changes were made in the objectives, policies or processes during the current and prior period.

SHARE CAPITAL

	2024 $'000	2023 $'000
Ordinary shares issued and fully paid	**718,881**	716,726

	2024 Thousands	2024 $'000	2023 Thousands	2023 $'000
Movement in ordinary shares on issue				
At 1 July	**2,631,530**	**716,726**	1,632,734	478,261
Equity issue[1]	**-**	**-**	248,855	58,596
Transfer from reserves[2]	**-**	**-**	747,097	179,508
Issuance of shares for performance rights and share appreciation rights	**8,507**	**2,155**	2,844	361
At 30 June	**2,640,037**	**718,881**	2,631,530	716,726

[1]In July 2022, the group raised $58.6 million (net of $2.4 million after tax costs) via the retail portion of the ANREO, being the second component of the 2022 equity raising. The first component comprised the institutional portion of the ANREO plus an institutional placement, with the combined cash from this first component received in June 2022. The retail portion of the ANREO resulted in the issuance of 248.9 million shares on 14 July 2022.
[2]At the end of June 2022, the group raised $179.5 million (net of $3.5 million after tax costs) via the institutional portion of the ANREO plus an institutional placement, being the first component of the 2022 equity raising. The second component comprised the retail portion of the ANREO which completed in July. While the total cash from the combination of the institutional portion of the ANREO and the institutional placement was received at the end of June 2022, the resulting 747.1 million shares were issued on 1 July 2022. As a result, the institutional component of the 2022 equity raising was recorded within reserves at 30 June 2022 and subsequently transferred from reserves to equity in July 2022.

ACCOUNTING POLICY

Issued and paid up capital is recognised as the fair value of the consideration received by the Group. The shares issued do not have a par value and there is no limit on the authorised share capital of the Group. Fully paid ordinary shares carry one vote per share, which entitles the holder to participate in the proceeds on winding up of the Company in proportion to the number of, and amounts paid on, the shares held.

Any transaction costs arising on the issue of ordinary shares that would not have been incurred had ordinary shares not been issued, are recognised directly in equity as a reduction of the share proceeds received.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

19. CONTRIBUTED EQUITY AND RESERVES CONTINUED

RESERVES

	Share capital reserve $'000	Consol. Reserve $'000	Share based payment reserve $'000	Option premium reserve $'000	Equity instruments reserve $'000	Total $'000
Consolidated						
At 30 June 2022	179,508	(541)	18,505	25	128	197,625
Other comprehensive income	-	-	-	-	648	648
Transferred to issued capital	(179,508)	-	(361)	-	-	(179,869)
Share-based payments	-	-	7,667	-	-	7,667
At 30 June 2023	**-**	**(541)**	**25,811**	**25**	**776**	**26,071**
Other comprehensive expenditure	**-**	**-**	-	**-**	**(412)**	**(412)**
Transferred to issued capital	**-**	**-**	**(2,155)**	**-**	**-**	**(2,155)**
Share-based payments	**-**	**-**	**3,681**	**-**	**-**	**3,681**
At 30 June 2024	**-**	**(541)**	**27,337**	**25**	**364**	**27,185**

NATURE AND PURPOSE OF RESERVES

Share capital reserve
This reserve is used to record receipts from equity issuance, where the shares have not been formally issued. This will be reclassified to share capital upon formal share issue.

Consolidation reserve
This reserve comprises the premium paid on acquisition of minority shareholdings in a controlled entity.

Share based payment reserve
This reserve is used to record the value of equity benefits provided to employees, contractors and executive directors as part of their remuneration.

Option premium reserve
This reserve is used to accumulate amounts received from the issue of options. The reserve can be used to pay dividends or issue bonus shares.

Equity instruments reserve
This reserve is used to capture the fair value movement in the value of equity instruments designated at fair value through Other Comprehensive Income. Items in this reserve are never recycled through profit or loss.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

20. FINANCIAL RISK MANAGEMENT

The Group's principal financial instruments comprise cash and short-term deposits (Note 5), receivables (Note 6), payables (Note 9), borrowings (Note 17) and other financial assets and liabilities as disclosed in the table below.

	2024 $'000	2023 $'000
Other financial assets – Non-Current		
Equity instruments	**718**	1,131
	718	1,131
Other financial liabilities – Non-Current		
Success fee financial liability	**2,830**	2,853
	2,830	2,853
Movement in carrying amount of the success fee financial liability:		
Carrying amount at 1 July	**2,853**	3,285
Accretion of success fee liability	**114**	110
Fair value adjustment	**(137)**	(542)
Carrying amount at 30 June	**2,830**	2,853

FAIR VALUE HIERARCHY

Fair value is the price that would be received to sell an asset, or the price that would be paid to transfer a liability, in an orderly transaction between market participants at the measurement date. All financial instruments for which fair value is recognised, or disclosed, are categorised within the fair value hierarchy, described as follows, and based on the lowest level input that is significant to the fair value measurement as a whole:

LEVEL 1
Quoted market prices in an active market (that are unadjusted) for identical assets or liabilities

LEVEL 2 Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable

LEVEL 3 Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable

For financial instruments that are recognised at fair value on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by re-assessing categorisation (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period. Set out below are the carrying amounts and fair values of financial instruments held by the Group:

		Carrying amount		Fair value	
	Level	2024 $'000	2023 $'000	2024 $'000	2023 $'000
Financial assets					
Trade and other receivables	**2**	**35,209**	28,797	**35,209**	28,797
Equity instruments	**1**	**718**	1,131	**718**	1,131
Financial liabilities					
Trade and other payables	**2**	**76,773**	87,941	**76,773**	87,941
Success fee financial liability	**3**	**2,830**	2,853	**2,830**	2,853
Interest bearing loans and borrowings	**2**	**253,147**	143,956	**264,847**	158,257

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

20. FINANCIAL RISK MANAGEMENT CONTINUED

The following summarises the significant methods and assumptions used in estimating the fair values of financial instruments.

EQUITY INSTRUMENTS

Equity instruments are not held for trading, and are measured at fair value through other comprehensive income based on an irrevocable election made at inception on an instrument basis.

They are initially recognised at fair value plus any directly attributable transaction costs. After initial recognition, investments are remeasured to fair value, determined by reference to their quoted market price on a prescribed equity stock exchange at the reporting date. Hence they are a Level 1 fair value measurement.

Changes in the fair value of equity investments are recognised as a separate component of equity and not recycled to profit and loss at any stage. Any dividends received are reflected in profit or loss.

SUCCESS FEE FINANCIAL LIABILITY

The success fee liability is the fair value of the Group's liability to pay a $5.0 million success fee upon the commencement of commercial production of hydrocarbons on the Group's VIC/RL 13-15 assets, which includes the Manta gas field, acquired on 7 May 2014.

The significant unobservable level 3 valuation inputs for the success fee financial liability include: a probability of 33% that no payment is made and a probability of 67% the payment is made in 2032. The discount rate used in the calculation of the liability as at 30 June 2024 equalled 4.31% (30 June 2023: 4.03%), reflecting a risk-free rate that aligns to the timing of payment. The financial liability is measured at fair value through profit and loss and valued using a discounted cash flow model. The value is sensitive to changes in discount rate and probability of payment. Significant changes in any of the key unobservable inputs would result in significantly higher or lower fair value measurement.

RISK MANAGEMENT

The Group manages its exposure to key financial risks in accordance with its risk management policy, with the objective to ensure that the financial risks inherent in gas and oil production and exploration activities are identified and then managed, or kept as low as reasonably practicable. The Group has a separate Risk & Sustainability Committee.

The main financial risks that arise in the normal course of business for the Group's financial instruments are foreign currency risk, commodity price risk, share price risk, credit risk, liquidity risk and interest rate risk. The Group uses different methods to measure and manage different types of risks to which it is exposed. These include monitoring exposure to foreign exchange risk and assessments of market forecasts for interest rates, foreign exchange rates and commodity prices. Liquidity risk is monitored through the development of future rolling cash flow forecasts.

The Board's policy is that no speculative trading in financial instruments be undertaken. The primary responsibility for the identification and control of financial risks rests with the Managing Director and the Chief Financial Officer, under the authority of the Board. The Board is apprised of these and other risks at Board meetings and agrees any policies that may be implemented to manage any of the risks identified below.

MARKET RISK

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises four types of risk: foreign currency risk, commodity price risk, interest rate risk and share price risk. Financial instruments affected by market risk include deposits, trade receivables, trade payables, accrued liabilities and borrowings.

The sensitivity analyses in the following sections relate to the position as at 30 June 2024 and 30 June 2023. The sensitivity analyses are intended to illustrate the sensitivity to changes in market variables on the Group's financial instruments and show the impact on profit or loss and shareholders' equity, where applicable.

When calculating the sensitivity analyses, it is assumed that the sensitivity of the relevant profit before tax item and/or equity, is the effect of the assumed changes in respective market risks, with all other variables held constant.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

20. FINANCIAL RISK MANAGEMENT CONTINUED

The Group has transactional currency exposure arising from oil sales which are denominated in United States dollars, whilst the great majority of costs are denominated in Australian dollars, with some costs incurred in United States dollars and Great British pounds. Transaction exposures, where possible, are netted off across the Group, to reduce volatility and provide a natural hedge.

a) Foreign currency risk

The Group may from time to time have cash denominated in United States ("US") dollars.

At 30 June 2024, the Group has no foreign exchange hedge programmes in place. The Group manages the purchase of foreign currency to meet expenditure requirements, which cannot be netted off against US dollar receivables.

The financial instruments which are denominated in US dollars are as follows:

	2024 $'000	2023 $'000
Financial assets		
Cash	**171**	29,956
Trade and other receivables	**2,274**	-

b) Commodity price risk

Commodity price risk arises from the sale of oil denominated in US dollars. From time to time, the Group may use oil price options to manage some of its oil price exposures.

The Group is exposed to changes in Southeast Australian gas spot prices, with respect to gas production in excess of contracted volumes. Spot gas trades at year end were executed with reference to the prevailing intraday price marker, i.e., at known settlement prices on the day.

c) Interest rate risk

The Group has borrowings of $265.0 million at 30 June 2024 (2023: $158.0 million). Interest on borrowings is at variable rates (refer to Note 17).

The Group has fixed rate term deposits that are not impacted by changes in the interest rate at the balance date.

d) Share price risk

Share price risk arises from the movement of share prices on a prescribed stock exchange. The Group has equity instruments measured at fair value through Other Comprehensive Income the fair value of which fluctuates, due to movements in the share price.

The following table summarises the sensitivity of financial instruments held at the year end, to the market risks above, with all other variables held constant.

	2024 $'000	2023 $'000
Foreign currency risk	**Impact on after tax profit**	
If the Australian dollar were 10% higher at the balance date	**(222)**	(2,723)
If the Australian dollar were 10% lower at the balance date	**272**	3,328
Interest rate risk		
If the interest rates were 100 basis points higher at the balance date	**(2,650)**	(1,580)
If the interest rates were 100 basis points lower at the balance date	**2,650**	1,580
Share price risk	**Impact on reserve**	
If the share price were 10% higher at the balance date	**72**	113
If the share price were 10% lower at the balance date	**(72)**	(113)

20. FINANCIAL RISK MANAGEMENT CONTINUED

Credit risk

Credit risk arises from the financial assets of the Group, which comprise cash and cash equivalents and trade and other receivables including hedge settlement receivables, escrow proceeds receivable (disclosed as other financial assets), and certain prepayments. The Group's exposure to credit risk arises from potential default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments.

The Group trades only with recognised creditworthy third parties and has a concentration of credit risk with trade receivables due from a small number of entities which have traded with the Group since 2003. Trade receivables are settled on a 35 day average term. The Group has some exposure to credit loss from other receivables and an amount of $30.8 million calculated on lifetime expected credit loss has been recognised in respect of credit-impaired joint venture related receivables.

Cash and cash equivalents are held at two financial institutions that each have a Standard & Poor's credit rating of AA- (stable).

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The liquidity position of the Group is managed to ensure sufficient liquid funds are available to meet all financial commitments in a timely and cost-effective manner. The Managing Director and Chief Financial Officer review the liquidity position on a regular basis, including cash flow forecasts, to determine the forecast liquidity position and maintain appropriate liquidity levels.

Any fluctuation of the interest rate either up or down will have only a limited impact on the principal amount of the cash on term deposit at the banks. The Group does not invest in financial instruments that are traded on any secondary market.

The table below summarises the maturity profile of the Group's financial liabilities based on contractual undiscounted payments:

	Less than 3 months $'000	3 to 12 months $'000	1 to 5 years $'000	Greater than 5 years $'000	Total $'000
At 30 June 2024					
Trade and other payables	**76,773**	**-**	**-**	**-**	**76,773**
Lease liabilities	**367**	**554**	**1,021**	**32**	**1,974**
Interest bearing loans and borrowings	**5,131**	**15,394**	**308,470**	**-**	**328,995**
Success fee financial liability	**-**	**-**	**-**	**5,000**	**5,000**
	82,271	**15,948**	**309,491**	**5,032**	**412,742**
At 30 June 2023					
Trade and other payables	68,679	-	19,262	-	87,941
Lease liabilities	495	1,428	9,284	1,056	12,263
Interest bearing loans and borrowings	3,022	9,066	197,286	-	209,374
Success fee financial liability	-	-	-	5,000	5,000
	72,196	10,494	225,832	6,056	314,578

GROUP STRUCTURE

21. INTERESTS IN JOINT ARRANGEMENTS

The Group has the following interests in joint arrangements involved in the exploration and/or production of gas and oil in Australia:

		Ownership Interest 2024	2023
Joint Arrangements in Australia in which Cooper Energy Limited is the operator/manager			
VIC/L24 & 30	Gas exploration and production	**50%**	50%
VIC/P44	Gas exploration	**50%**	50%
Athena Processing Plant	Gas processing services	**50%**	50%
Joint Arrangements in Australia in which Cooper Energy Limited is not the operator/manager			
PEL 494	Gas and oil exploration	**30%**	30%
PEP 168	Gas and oil exploration	**50%**	50%
PEP 171	Gas and oil exploration	**75%**	75%
PRL 32	Gas and oil exploration	**30%**	30%
PEL 680	Gas and oil exploration	**30%**	30%
PRL 85-104[1] (Formerly PEL 92)	Oil and gas exploration and production	**25%**	25%

[1] Includes associated PPLs.

ACCOUNTING POLICY

The Group has interests in arrangements that are controlled jointly. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control. A joint arrangement is either a joint operation or a joint venture. The Group has several joint arrangements which are classified as joint operations. A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

In relation to its interests in joint operations, the Group recognises its share of:

- Assets, including its share of any assets held jointly
- Liabilities, including its share of any liabilities incurred jointly
- Revenue from the sale of its share of the output arising from the joint operation
- Expenses, including its share of any expenses incurred jointly

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

Joint arrangements

Judgement is required to determine when the Group has joint control over an arrangement, which requires an assessment of the relevant activities and when the decisions in relation to those activities require unanimous consent. The Group has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, such as approval of the capital expenditure program for each year and appointing, remunerating and terminating the key management personnel or service providers of the joint arrangement. Where joint control does not exist, the relationship is not accounted for as a joint arrangement. The considerations made in determining joint control are similar to those necessary to determine control over subsidiaries.

Judgement is also required to classify a joint arrangement. Classifying the arrangement requires the Group to assess their rights and obligations arising from the arrangement. Specifically, the Group considers:

- the structure of the joint arrangement – whether it is structured through a separate vehicle; and
- when the arrangement is structured through a separate vehicle, the rights and obligations arising from the legal form of the separate vehicle, the terms of the contractual arrangement, and other facts and circumstances (when relevant).

This assessment often requires significant judgement. A different conclusion on joint control, and also whether the arrangement is a joint operation or a joint venture, may materially impact the accounting.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

22. INVESTMENTS IN CONTROLLED ENTITIES

(a) Deed of Cross Guarantee
Pursuant to ASIC Corporations (Wholly-owned Companies) Instrument 2016/785 dated 29 September 2016, relief has been granted to certain controlled entities of Cooper Energy Limited from the Corporations Act 2001 for preparation, audit and lodgement of financial reports, and directors' reports. As a condition of the Class Order, Cooper Energy Limited, and the controlled entities subject to the Class Order, entered into a Deed of Cross Guarantee.

The effect of the deed is that Cooper Energy Limited has guaranteed to pay any deficiency in the event of the winding up of any member of the Closed Group, and each member of the Closed Group has given a guarantee to pay any deficiency, in the event that Cooper Energy Limited or any other member of the Closed Group is wound up.

(b) Schedule of controlled entities
The Group's consolidated financial statements include the financial statements of Cooper Energy Limited and the subsidiaries listed in the following table.

			Ownership Interest	
Name	**Country of incorporation**	**Note**	**2024**	2023
Somerton Energy Limited	Australia	(a)	**100%**	100%
Essential Petroleum Exploration Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Australia) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (PBF) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (PB Pipelines) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (CH) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (TC) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (MF) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (MGP) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (IC) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (HC) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (EA) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Sole) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (VO) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Marketing) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (BMG) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (CB) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (Finance) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (AGP) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (CS) Pty Ltd	Australia	(a)	**100%**	100%
Cooper Energy (MS) Pty Ltd	Australia	(a)	**100%**	100%

The parties that comprise the Closed Group are denoted by (a).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

22. INVESTMENTS IN CONTROLLED ENTITIES CONTINUED

ACCOUNTING POLICY

Business combinations are accounted for using the acquisition method. The consideration for an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest in the acquiree. For each business combination, the Group elects whether it measures the non-controlling interest in the acquiree at fair value, or at the proportionate share of the acquiree's identifiable net assets. Acquisition costs incurred are expensed and included in administrative expenses.

When the Group acquires a business, it assesses the financial assets and liabilities acquired for appropriate classification and designation per AASB 9 *Financial Instruments* (AASB 9), in accordance with the contractual terms, economic circumstances and pertinent conditions, as at the acquisition date. If the business combination is achieved in stages, the acquisition date fair value of the acquirers previously held equity interest in the acquiree is remeasured to fair value at the acquisition date, through profit or loss.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration that is deemed to be an asset or liability will be recognised in accordance with AASB 9 and measured at fair value, through profit and loss. If the contingent consideration is classified as equity, it will not be remeasured. Subsequent settlement is accounted for within equity. In instances where the contingent consideration does not fall within the scope of AASB 9, it is measured in accordance with the appropriate AASB.

An asset or group of assets that do not meet the definition of a business are accounted for as asset acquisitions. Under this method, assets are initially recognised at cost based on their relative fair value at the date of acquisition. Under this method transaction costs are capitalised to the asset and not expensed.

23. PARENT ENTITY INFORMATION

Information relating to the parent entity, Cooper Energy Limited	**2024 $'000**	2023 (restated) $'000
Current Assets	**126,135**	144,598
Total Assets	**460,395**	712,281
Current Liabilities	**57,694**	186,501
Total Liabilities	**118,601**	223,784
Issued capital	**718,881**	716,726
Accumulated loss	**(404,449)**	(254,064)
Option premium reserve	**25**	25
Share based payment reserve	**27,337**	25,810
Total shareholders' equity	**341,794**	488,497
Loss of the parent entity	**(150,385)**	(161,481)
Total comprehensive loss of the parent entity	**(150,385)**	(161,481)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

OTHER INFORMATION

24. COMMITMENTS FOR EXPENDITURE

The Group has the following commitments for exploration expenditure for which no liabilities have been record in the financial statements as the goods or services have not been received.

	2024 $'000	2023 $'000
Due within 1 year	**32,403**	32,263
Due within 1-5 years	**33,878**	478
	66,281	32,741

From time to time through the ordinary course of business, Cooper Energy enters into contractual arrangements that may give rise to negotiated outcomes.

Cooper Energy has executed a number of material contracts to the value of $44.6 million at 30 June 2024 relating to the East Coast Supply Project. The minimum payment under these contracts at 30 June 2024 is $23.5 million.

As at 30 June 2024 the parent entity has bank guarantees for $7.4 million (2023: $7.7 million), see also Note 17. These guarantees are in relation to credit support for gas purchases and guarantees on office leases.

25. CONTINGENT LIABILITIES

Contingent liabilities arise in the ordinary course of business through commercial disputes or claims, including contractual or third-party claims. These contingent liabilities are possible obligations whose existence will only be confirmed by the occurrence or non-occurrence of uncertain future events. Because it is not probable that a future sacrifice of economic benefits will be required, or the amount of the obligation cannot be measured with sufficient reliability, the Group has not provided for these amounts in the financial statements.

26. SHARE BASED PAYMENTS

The Company's amended EIP was approved by shareholders at the 2022 AGM. The EIP applies only to Executive KMPs and a small number of senior staff. Performance rights were issued for no consideration under the EIP under two tranches:

- Tranche 1 – relative total shareholder return (RTSR)
- Tranche 2 – absolute total shareholder return (ATSR).

No share appreciation rights were issued in the financial year. Those share appreciation rights issued in previous financial year remain on foot and subject to testing. Issued rights vest as shares in the parent entity, subject to performance hurdles being met.

A performance right is the right to acquire one fully paid share in the Company, provided a specified hurdle is met. Share appreciation rights are rights to acquire shares in the Company to the value of the difference in the Company share price between the grant date and vesting date.

Testing of the performance rights and historical share appreciation rights occur at the end of the three year performance period.

The vesting of tranche 1 performance rights is based on a comparison of the Company's RTSR percentile ranking against the RTSR of a peer group of nine other companies. Subject to the plan rules, the number of tranche 1 performance rights that will vest at the end of the performance period is as follows:

- Below 50th percentile – no tranche 1 performance rights will vest
- At 50th percentile – 50% of tranche 1 performance rights will vest
- Between 50th and 75th percentile – 50% of tranche 1 performance rights plus 2% for each additional percentile
- 75th percentile or greater – 100% of tranche 1 performance rights will vest

The vesting of tranche 2 performance rights takes account only of the Company's ATSR, calculated as the compound average growth rate (CAGR) of the Company's share price over a 3 year period. Subject to the plan rules, the number of tranche 2 performance rights that will vest at the end of the performance period is as follows:

- Less than 10% CAGR – no tranche 2 performance right will vest

For the year ended 30 June 2024

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

26. SHARE BASED PAYMENTS CONTINUED

- At 10% CAGR – 50% of tranche 2 performance rights will vest
- Between 10% and 20% CAGR – 50% of tranche 2 performance rights will vest, plus 5% for each additional percentile
- 20% or above – 100% of tranche 2 performance rights will vest

Performance rights are also granted as part of deferred awards under the short-term incentive plan ("STIP"). Testing of these rights will occur at the end of a 12-month performance period. Rights granted will vest if the employee remains employed by the Company at the end of the performance period.

There are no participating rights or entitlements inherent in the rights and holders will not be entitled to participate in new issues of capital offered to shareholders during the period of the rights. All rights are settled by physical delivery of shares.

Information with respect to the number of performance rights and share appreciation rights granted to employees is as follows:

Date Granted	Number of share appreciation rights (SARs) granted	Number of performance rights granted	Average share price at commencement date of grant	Average contractual life of rights at grant date in years	Remaining life of rights in years
9 December 2021	**28,449,812**	**9,043,984**	**$0.270**	**3**	**0.5**
9 December 2022	**20,636,373**	**7,608,195**	**$0.195**	**3**	**1.5**
23 November 2023	**1,084,611**	**407,814**	**$0.105**	**3**	**1.5**
23 November 2023	**-**	**9,547,387**	**$0.105**	**3**	**2.4**
11 December 2023	**-**	**29,249,252**	**$0.100**	**3**	**2.5**
11 December 2023	**-**	**9,231,865**	**$0.100**	**1**	**0.5**

The number of performance rights and share appreciation rights held by employees is as follows:

	Number of Share Appreciation Rights 2024	2023	Number of Performance Rights[1] 2024	2023
Balance at beginning of year	**60,807,624**	71,695,778	**28,694,792**	26,086,626
- granted	**1,084,611**	20,636,373	**48,436,318**	16,249,700
- vested	**-**	-	**(8,506,969)**	(2,844,324)
- expired and not exercised	**(16,796,442)**	(25,781,761)	**(5,460,544)**	(8,772,365)
- forfeited	**(1,337,585)**	(5,742,766)	**(425,208)**	(2,024,845)
Balance at end of year	**43,758,208**	60,807,624	**62,738,389**	28,694,792
Achieved at end of year	**-**	-	**-**	-

[1] The Performance Rights, which vested in 2023 and 2024, are Deferred STIP that applies to staff generally and does not include any PRs having vested under the EIP for Executive KMP.

The fair value of services received in return for the performance rights granted are measured by reference to the fair value of performance rights granted. The estimate of the fair value of the services received is measured based on the Black-Scholes methodology and a Monte-Carlo simulation model that allows for the incorporation of market-based performance hurdles that must be met before the shares vest to the holder.

Fair value assumptions on LTIP grants	**10 December 2021**	**9 December 2022**	**11 December 2023**
Fair value of share appreciation rights at measurement date	8.3 cents	6.4 cents	N/A
Fair value of performance rights at measurement date	18.5 cents	13.4 cents	7.0 cents
Share price	27.0 cents	19.5 cents	10.0 cents
Risk free interest rate	0.97%	3.02%	3.80%
Expected volatility	48%	52%	53%
Dividend yield	0%	0%	0%

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

26. SHARE BASED PAYMENTS CONTINUED

ACCOUNTING POLICY

The Group provides benefits to employees of the Group in the form of share-based payment transactions, whereby employees render services in exchange for rights over shares ("equity-settled transactions").

The cost of these equity-settled transactions with employees is measured by reference to the fair value at the date at which they are granted and are recorded as an expense, with a corresponding increase in reserves, on a straight-line basis over the vesting period of the related instrument.

The fair value is determined using the Black-Scholes methodology and a Monte-Carlo simulation model that takes into account the exercise price, the vesting period, the vesting and performance criteria, the non-tradable nature of the performance right or share appreciation right, the share price at grant date, the expected volatility of the price of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the vesting period.

There are no non-market vesting conditions (e.g., profitability, or sales growth targets), and as such the estimation of the fair value of the performance rights and share appreciation rights granted is based solely on the results of the Black-Scholes based Monte-Carlo simulation model.

The volatility assumption is based on the actual volatility of Cooper Energy's daily closing share price over the three-year period to the valuation date.

The cost of equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and/or service conditions are fulfilled, ending on the date on which the relevant employees become fully entitled to the award (the vesting period).

The cumulative expense recognised for equity-settled transactions at each reporting date until vesting date reflects:

- the extent to which the vesting period has expired; and
- the Group's best estimate of the number of equity instruments that will ultimately vest.

No adjustment is made for the likelihood of market performance conditions being met as the effect of these conditions is included in the determination of fair value at grant date. The Consolidated Statement of Comprehensive Income charge or credit, for a period, represents the movement in cumulative expense recognised as at the beginning and end of that period.

No expense is recognised for awards that do not ultimately vest, except for awards where vesting is only conditional upon a market condition.

If the terms of an equity-settled award are modified, as a minimum an expense is recognised as if the terms had not been modified. In addition, an expense is recognised for any modification that increases the total fair value of the share-based payment arrangement, or is otherwise beneficial to the employees as measured at the date of modification.

If an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. However, if a new award is substituted for the cancelled award and designated as a replacement award on the date that it is granted, the cancelled and new award are treated as if they were a modification of the original award, as described in the previous paragraph.

The dilutive effect, if any, of outstanding performance rights and share appreciation rights is reflected as additional share dilution in the computation of diluted earnings per share.

SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The Group measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. The fair value is determined by an external valuation expert using the calculation criteria.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

27. RELATED PARTY DISCLOSURES

The Group has a related party relationship with its joint arrangements (Note 21), its subsidiaries (Note 22), and its key management personnel (disclosure below).

The key management personnel's remuneration included in General Administration (see Note 2) is as follows:

	2024 $	2023 $
Short-term benefits	**5,390,663**	5,829,184
Other long-term benefits	**23,413**	89,311
Post-employment benefits	**217,887**	303,572
Performance rights and share appreciation rights	**896,020**	2,193,542
Termination benefits	**823,314**	2,534,604
	7,351,297	10,950,213

28. REMUNERATION OF AUDITORS

	2024 $	2023 $
The auditor of Cooper Energy Limited is Ernst & Young		
Audit services		
Amounts received or due and receivable by Ernst & Young Australia for:		
Audit of statutory report of Cooper Energy Limited	**463,800**	486,380
	463,800	486,380
Other services		
Taxation and other services	**62,000**	49,500
	62,000	49,500
Total fees to Ernst & Young	**525,800**	535,880

29. EVENTS AFTER THE REPORTING PERIOD

There are no significant events subsequent to 30 June 2024 at the date of this report.

For the year ended 30 June 2024

CONSOLIDATED ENTITY DISCLOSURE STATEMENT

Entity name	Entity type	Body corporate country of incorporation	Body corporate % of share capital held	Country of tax residence
Cooper Energy Limited	Body corporate	Australia	100%	Australia
Somerton Energy Limited	Body corporate	Australia	100%	Australia
Essential Petroleum Exploration Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Australia) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (PBF) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (PB Pipelines) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (CH) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (TC) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (MF) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (MGP) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (IC) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (HC) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (EA) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Sole) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (VO) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Marketing) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (BMG) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (CB) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (Finance) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (AGP) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (CS) Pty Ltd	Body corporate	Australia	100%	Australia
Cooper Energy (MS) Pty Ltd	Body corporate	Australia	100%	Australia

DIRECTORS' DECLARATION

In accordance with a resolution of the Directors of Cooper Energy Limited, I state that:

In the opinion of the Directors:

(a) the financial statements and notes of the consolidated entity are in accordance with the *Corporations Act 2001*, including:

(i) giving a true and fair view of the consolidated entity's financial position as at 30 June 2024 and of its performance for the year ended on that date; and

(ii) complying with Australian Accounting Standards and the Corporations Regulations 2001;

(b) the financial statements and notes also comply with International Financial Reporting Standards as disclosed in the Basis of Preparation;

(c) the consolidated entity disclosure statement required by section 295(3A) of the Corporations Act is true and correct; and

(d) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

This declaration has been made after receiving the declarations required to be made to the Directors in accordance with section 295A of the Corporations Act 2001 for the financial year ended 30 June 2024.

In the opinion of the Directors, as at the date of this declaration, there are reasonable grounds to believe that the members of the closed group identified in Note 22 will be able to meet any obligations or liabilities to which they are, or may become subject, by virtue of the Deed of Cross Guarantee between the Company and those members of the Closed Group pursuant to ASIC Corporations (Wholly-owned Companies) Instrument 2016/785.

Signed in accordance with a resolution of the Directors.

Mr John C. Conde AO
Chairman

27 August 2024

Ms Jane L. Norman
Managing Director and CEO

COOPER ENERGY

INDEPENDENT AUDITOR'S REPORT TO THE MEMBERS OF COOPER ENERGY LIMITED

Building a better working world

Ernst & Young
121 King William Street
Adelaide SA 5000 Australia
GPO Box 1271 Adelaide SA 5001

Tel: +61 8 8417 1600
Fax: +61 8 8417 1775
ey.com/au

Independent auditor's report to the members of Cooper Energy Limited

Report on the audit of the financial report

Opinion

We have audited the financial report of Cooper Energy Limited (the Company) and its subsidiaries (collectively the Group), which comprises the consolidated statement of financial position as at 30 June 2024, the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year then ended, notes to the financial statements, including material accounting policy information, the consolidated entity disclosure statement and the directors' declaration.

In our opinion, the accompanying financial report of the Group is in accordance with the *Corporations Act 2001*, including:

a. Giving a true and fair view of the consolidated financial position of the Group as at 30 June 2024 and of its consolidated financial performance for the year ended on that date; and

b. Complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report. We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial report of the current year. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, but we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the financial report* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the financial report. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying financial report.

A member firm of Ernst & Young Global Limited
Liability limited by a scheme approved under Professional Standards Legislation

1. Carrying value of gas and oil assets and exploration and evaluation assets

Why significant	How our audit addressed the key audit matter
At 30 June 2024, the Group's Gas and Oil assets and Exploration and Evaluation assets are valued at $475 million and $194 million respectively. At year-end, the Group identified an indicator of impairment in respect of a single Exploration and Evaluation asset, for which an impairment charge of $0.3m was recognised, as disclosed in Note 14 of the financial report. In accordance with the requirements of Australian Accounting Standards, the Group is required to assess in respect of the reporting period, whether there is any indication that an asset may be impaired, or conversely whether reversal of a previously recognised impairment may be required. If any impairment indicators exist, an entity shall estimate the recoverable amount of the asset or cash generating unit ('CGU'). The assessments for indicators of impairment and reversals of impairment are judgmental and include assessing a range of external and internal factors, including the determination of preliminary recoverable amounts for CGUs where relevant. Where impairment indicators are identified throughout the period, forecasting cash flows for the purpose of determining the recoverable amount of a CGU, including a preliminary recoverable amount, involves accounting estimates and judgements and is affected by expected future performance and market conditions. Key forecast assumptions, such as discount rates, foreign exchange rates, commodity prices and recoverable hydrocarbon reserves used in the Group's impairment assessment are disclosed in Note 14. We considered the impairment testing of the Group's CGUs and its exploration and evaluation assets throughout the period, and the related disclosures in the financial report, to be a key audit matter.	*Assessing indicators of impairment* We evaluated whether there had been significant changes to the external or internal factors considered by the Group, in assessing whether indicators of impairment or reversal of impairment existed throughout the period. Those indicators included specific matters related to the Group, CGUs, and industry as well as broader market-based indicators. *Impairment testing of CGUs for which triggers were identified and the determination of preliminary recoverable amounts when assessing indicators of impairment of CGUs* We assessed the composition of the forecast cash flows and the reasonableness of key inputs used to formulate recoverable amounts. Depending on the CGU, our audit procedures included: ► Reconciling future production profiles to the latest hydrocarbon reserves and resources estimates (discussed further below), current sanctioned development budgets, long-term asset plans and historical operations. ► Developing a reasonable range of forecast oil and gas prices, based upon external data. We compared this range to the Group's forecast oil and gas price assumptions to challenge whether the Group's assumptions were reasonable. In developing our ranges, we obtained a variety of reputable third-party forecasts, peer information and market data (which contemplate forecast oil and gas demand in a decarbonising global economy). ► Evaluating discount rates used by the Group for impairment tests (which contemplate costs of capital considerations in light of a decarbonising global economy). ► Evaluating the reasonableness of inflation rates, foreign exchange rates and carbon costs used by the Group for impairment tests. ► Understanding the operational performance of the CGUs relative to plan, comparing future operating and development expenditure within the impairment assessments to current sanctioned budgets, historical expenditures and future project plans, and ensuring variations were in accordance with our expectations. ► Testing the mathematical accuracy of the Group's discounted cash flow models. *Future production profiles* A key input to impairment assessments is the Group's production forecast, which is closely related to the Group's hydrocarbon reserves and resource estimates and development plans. Our audit procedures on the work of the Group's internal and external experts included:

Why significant	How our audit addressed the key audit matter
	► Assessing the processes and controls associated with estimating reserves and resources. ► Reading reports provided by internal and external experts and assessing their scopes of work and findings. ► Assessing the qualifications, competence and objectivity of the Group's internal and external experts involved in the estimation process. ► Understanding the reasons for reserve changes or the absence of reserves changes, for consistency with other information that we obtained throughout the audit. *Impact of Sustainability and Climate Change Risks* In undertaking our impairment audit procedures, we incorporated consideration of sustainability and climate change related risks by: ► Performing sensitivity analysis of recoverable amounts across a range of key inputs which have been formulated to incorporate uncertainty risk associated with climate change, such as the inclusion of premiums in discount rates and alternative price forecasts which contemplate varied climate change assumptions and scenarios. ► Reviewing the recoverable amount for the appropriate inclusion of carbon costs. ► Assessing the audit results of procedures carried out over restoration and rehabilitation obligations and their impact on impairment risk (refer to the 'Accounting for Restoration Obligations' Key Audit Matter below). ► Inquiring of management and reading the Group's communication and publicly stated climate commitments regarding sustainability and climate-related risks where relevant and their impact on financial reporting. ► Assessing whether the 'other information' presented by the Group, including their publicly stated climate commitments present a current period impairment indicator for any CGUs at reporting date. *Exploration and Evaluation Assets* For exploration and evaluation assets, we assessed whether any impairment indicators, per the requirements of AASB 6: *Exploration for and Evaluation of Mineral Resources*, were present, and performed audit procedures in respect of the conclusions reached by management, including: ► Assessing whether the Group's right to explore was current, which included obtaining and assessing supporting documentation such as licenses, permits and agreements.

Why significant	How our audit addressed the key audit matter
	▶ Assessing the Group's intention to carry out significant ongoing exploration and evaluation activities in the relevant areas of interest and enquiring of senior management as to their intentions and the strategy of the Group as it relates to particular areas of interest. ▶ Assessing whether exploration and evaluation data or other information existed to indicate that the carrying value of capitalised exploration and evaluation assets was unlikely to be recovered through successful evaluation and development or sale. We also assessed the adequacy of the disclosures included in the Notes to the financial statements.

2. Restoration obligations

Why significant	How our audit addressed the key audit matter
At 30 June 2024, the Group has recognised provisions for restoration obligations relating to onshore and offshore assets of $461 million. As disclosed in Note 15, the calculation of restoration provisions is conducted by specialist engineers and requires significant judgements, assumptions and estimates to be made by the Group regarding removal date, compliance with environmental legislation and regulations, the extent of restoration activities required, the engineering methodology for estimating costs, future removal technologies in determining the removal costs and liability-specific discount rates to determine the present value of these cash flows. The judgements and estimates in respect of restoration provisions are based upon conditions existing at 30 June 2024, including key assumptions related to certain items remaining in-situ. Australian regulatory approval for these items remaining in-situ will only be sought towards the end of the respective asset's field life and accordingly, at 30 June 2024, there is uncertainty whether the Australian regulator will approve plans for these items to be decommissioned in-situ. Changes to these significant judgements, assumptions and estimates can lead to changes in the restoration provisions. Accordingly, the restoration provision calculation and the related disclosures in the financial report are a key audit matter.	We assessed the restoration obligation provisions prepared by the Group, evaluating the assumptions and methodologies used and the estimates made. Our audit procedures included the following: ▶ Evaluating the Group's process for identifying its legal and regulatory obligations for restoration and decommissioning and testing the completeness of operating locations. ▶ Understanding and documenting the controls over the Group's internal methodology for determining and approving gross cost estimates used to calculate the Group's restoration provisions. ▶ In conjunction with our environmental specialists, assessing the reasonableness and completeness of restoration cost estimates based on the relevant current legal and regulatory requirements. ▶ Assessing the qualifications, competence and objectivity of the Group's internal and external experts engaged to carry out the gross restoration cost estimations as a basis for our reliance on the output of their work. ▶ Comparing current year cost estimates to those of the prior year and explanations from management and both internal and external experts for observed changes. ▶ Comparing the timing of the future cash outflows against the anticipated end-of-field lives, cross-checking that these dates were consistent with the Group's reserve estimates, impairment calculations and regulatory notices. ▶ Evaluating the appropriateness of the discount rates, inflation rates and foreign exchange rates used to calculate the present value of each of the provisions.

Why significant	How our audit addressed the key audit matter
	▶ Testing the mathematical accuracy of the restoration provision calculations. *Impact of Sustainability and Climate Change Risks* In undertaking our audit procedures for restoration, we incorporated consideration of sustainability and climate change related risks by: ▶ Understanding the regulatory framework in which each project operates to ensure compliance with the regulatory requirements of the various jurisdictions as they relate to restoration obligations. ▶ Evaluating the assumptions associated with the form and extent of abandonment activities, including conformity with regulation and industry practice, and the nature of the items expected to be left in-situ in abandonment activities. ▶ Reviewing litigation registers, correspondence with solicitors and regulators to confirm the completeness of liabilities recognised. ▶ Considering the estimated dates for the commencement of restoration and rehabilitation activities, possible impacts of physical risks of climate change and performing sensitivity analyses aligned with a range of scenarios associated with the Group's net zero climate targets. We also assessed the adequacy of the disclosures included in the Notes to the financial report.

Information other than the financial report and auditor's report thereon

The directors are responsible for the other information. The other information comprises the information included in the Company's 30 June 2024 annual report other than the financial report and our auditor's report thereon. We obtained the directors' report and the Overall Financial Review that are to be included in the annual report, prior to the date of this auditor's report, and we expect to obtain the remaining sections of the annual report after the date of this auditor's report.

Our opinion on the financial report does not cover the other information and we do not and will not express any form of assurance conclusion thereon, with the exception of the Remuneration Report and our related assurance opinion.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of:

- The financial report (other than the consolidated entity disclosure statement) that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001;* and
- The consolidated entity disclosure statement that is true and correct in accordance with the *Corporations Act 2001*; and

for such internal control as the directors determine is necessary to enable the preparation of:

- The financial report (other than the consolidated entity disclosure statement) that gives a true and fair view and is free from material misstatement, whether due to fraud or error; and
- The consolidated entity disclosure statement that is true and correct and is free of misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the Group's ability to continue as a going concern, disclosing, as applicable, matters relating to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

As part of an audit in accordance with the Australian Auditing Standards, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.

- Conclude on the appropriateness of the directors' use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial report or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Group to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial report, including the disclosures, and whether the financial report represents the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the financial report. We are responsible for the direction, supervision and performance of the Group audit. We remain solely responsible for our audit opinion.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, actions taken to eliminate threats or safeguards applied.

From the matters communicated to the directors, we determine those matters that were of most significance in the audit of the financial report of the current year and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on the audit of the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 69 to 92 of the directors' report for the year ended 30 June 2024.

In our opinion, the Remuneration Report of Cooper Energy Limited for the year ended 30 June 2024, complies with section 300A of the *Corporations Act 2001*.

EY

Building a better working world

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.

Ernst & Young

D Hall
Partner
Adelaide
27 August 2024

A member firm of Ernst & Young Global Limited
Liability limited by a scheme approved under Professional Standards Legislation

COOPER ENERGY

AUDITOR'S INDEPENDENCE DECLARATION TO THE DIRECTORS OF COOPER ENERGY LIMITED

EY
Building a better working world

Ernst & Young
121 King William Street
Adelaide SA 5000 Australia
GPO Box 1271 Adelaide SA 5001

Tel: +61 8 8417 1600
Fax: +61 8 8417 1775
ey.com/au

Auditor's Independence Declaration to the Directors of Cooper Energy Limited

As lead auditor for the audit of the financial report of Cooper Energy Limited for the financial year ended 30 June 2024, I declare 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 audit;

b. No contraventions of any applicable code of professional conduct in relation to the audit; and

c. No non-audit services provided that contravene any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Cooper Energy Limited and the entities it controlled during the financial year.

Ernst & Young

D Hall
Partner
Adelaide
27 August 2024

A member firm of Ernst & Young Global Limited
Liability limited by a scheme approved under Professional Standards Legislation

SECURITIES EXCHANGE AND SHAREHOLDER INFORMATION

As at 31 August 2024

LISTING

The Company's shares are quoted on the Australian Securities Exchange under the code of "COE".

NUMBER OF SHAREHOLDERS

There were 8,066 shareholders as at 31 August 2024. All issued shares carry voting rights. On a show of hands every member at a meeting of shareholders shall have one vote and upon a poll each share shall have one vote.

DISTRIBUTION OF SHAREHOLDING (AT 31 AUGUST 2024)

Range	Total holders	Shares	% of Total Shares
1-1,000	974	249,592	0.01
1,001 - 5,000	2,030	5,825,015	0.22
5,001 - 10,000	1,250	10,190,857	0.39
10,001 - 100,000	3,968	109,533,881	4.15
>100,001	844	2,514,238,884	95.23
Total	8,066	2,640,038,229	100.00

UNQUOTED OPTIONS ON ISSUE

Nil

UNQUOTED PERFORMANCE RIGHTS

Number of Holders of Performance Rights	Total Rights
103	62,647,935 Performance Rights
13	43,758,208 Share Appreciation Rights

UNMARKETABLE PARCELS

At 31 August 2024 there were 1,973 shareholders, representing 2,065,995 shares, holding less than a marketable parcel of 2,565 shares in the company.

TWENTY LARGEST SHAREHOLDERS

Rank	Shareholder Name	Shares	%
1	CITICORP NOMINEES PTY LIMITED	539,276,586	20.43
2	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED	492,937,325	18.67
3	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED - A/C 2	352,010,888	13.33
4	J P MORGAN NOMINEES AUSTRALIA PTY LIMITED	344,905,904	13.06
5	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED-GSCO ECA	93,604,725	3.55
6	MCCUSKER HOLDINGS PTY LTD	70,000,000	2.65
7	UBS NOMINEES PTY LTD	52,623,935	1.99
8	NATIONAL NOMINEES LIMITED	31,494,393	1.19
9	BNP PARIBAS NOMS PTY LTD <GLOBAL MARKETS>	29,344,642	1.11
10	HSBC CUSTODY NOMINEES (AUSTRALIA) LIMITED <NT-COMNWLTH SUPER CORP A/C>	23,403,710	0.89
11	BNP PARIBAS NOMINEES PTY LTD <AGENCY LENDING A/C>	21,157,513	0.80
12	WARNEET SUPER PTY LTD <WARNEET SUPER FUND A/C>	17,500,000	0.66
13	BOND STREET CUSTODIANS LIMITED <LAMAN - D05019 A/C>	16,911,110	0.64
14	INVIA CUSTODIAN PTY LIMITED <DAVID PETER MAXWELL A/C>	13,095,442	0.50
15	MR SIMON HANNES + MRS MIGNON CATHERINE BOOTH <SGH SUPER FUND A/C>	9,895,323	0.37
16	AUDANT INVESTMENTS PTY LIMITED <WARNEET SUPER FUND A/C>	9,050,000	0.34
17	BNP PARIBAS NOMS PTY LTD	8,258,940	0.31
18	WANNA QUICKIE PTY LTD	7,984,607	0.30
19	SRGG PTY LTD <GIUDICE SUPER A/C>	7,892,158	0.30
20	INVIA CUSTODIAN PTY LIMITED <LEWXAM SUPER FUND A/C>	7,175,387	0.27
Total Top 20 holders		**2,148,522,588**	**81.38**
Total Remaining Holders Balance		**491,515,641**	**18.62**

SUBSTANTIAL SHAREHOLDERS

The following were substantial holders in the company as at 31 August 2024, as disclosed in substantial holding notices given to the Company as required by section 671B of the Corporations

Name of entity	Number of securities in which substantial shareholder has a relevant interest as at date of last notice	Voting power as at date of last notice
L1 Capital Pty Limited	416,802,185	15.79%
Challenger Limited and Apollo Global Management, Inc. and their associated entities	175,681,366	6.65%
Greencape Capital Pty Ltd	175,681,366	6.65%
Yarra Capital Management and its associated entities	135,326,636	5.13%
The Vanguard Group, Inc and its associated entities	132,315,772	5.17%

ENQUIRIES AND SHARE REGISTRY ADDRESS

Shareholders with enquiries about their shareholdings should contact the Company's share registry, Computershare Investor Services Pty Ltd, via the contact details in the Corporate Directory of this Annual Report.

ONLINE SHAREHOLDER INFORMATION

Shareholders can obtain information about their holdings or view their account instructions online, as well as download forms to update their holder details. For identification and security purposes, you will need to know your Holder Identification Number (HIN/SRN), Surname/Company Name and Post/Country Code to access. This service is accessible via the Computershare website.

CHANGE OF ADDRESS

Shareholders who have changed their address should advise Computershare in writing or online via the Computershare website. Written notification can be mailed or faxed to Computershare and must include both old and new addresses and the security holder reference number (SRN) of the holding. Change of address forms are available for download from the Computershare website. Shareholders who have broker sponsored holdings should contact their broker to update these details.

ANNUAL REPORT MAILING LIST

Shareholders who wish to vary their annual report mailing arrangements should advise Computershare online via the Computershare website. Electronic versions of the report are available to all via the Company's website. Annual Reports will be mailed to all shareholders who have elected to be placed on the mailing list for this document.

FORMS FOR DOWNLOAD

All forms relating to amendment of holding details and holder instructions to the Company are available for download from the Computershare website.

INVESTOR INFORMATION

Information about the Company is available from a number of sources:

Website cooperenergy.com.au

E-news Shareholders can nominate to receive Company information electronically. This service is hosted by Computershare and can be accessed via Computershare's website.

Publications The Annual Report is the major printed source of Company information. Other publications include the Sustainability Report, half-yearly and quarterly reports, company press releases and investor presentations. All publications can be obtained either through the Company's website or by contacting the Company.

Telephone or email enquiry
Tom Fraczek
Investor Relations & Treasurer
+61 439 555 165
tom.fraczek@cooperenergy.com.au

This Annual Report has been prepared to provide Shareholders with an overview of Cooper Energy Limited's performance for the 2024 financial year and its outlook. The Annual Report is mailed to shareholders who elect to receive a copy and is available free of charge on request (see Shareholder Information printed in this Annual Report). This Annual Report and other information about the company can be accessed via the Company's website at www.cooperenergy.com.au

ANNUAL GENERAL MEETING

Date of meeting Thursday, 7 November 2024
Time of meeting: 10:30 am (ACDT)
Place of meeting U City, Level 1,
43 Franklin Street, Adelaide SA 5000

The Notice of Meeting has been mailed to Shareholders. Additional copies can be obtained from the Company's registered office or downloaded from our website at www.cooperenergy.com.au

ABBREVIATIONS AND TERMS

This Report uses terms and abbreviations relevant to the Group, its accounts and the petroleum industry.

The terms "the Company" and "Cooper Energy" and "the Group" are used in the report to refer to Cooper Energy Limited and/or its subsidiaries. The terms "2024", or "2024 financial year" refer to the 12 months ended 30 June 2024 unless otherwise stated. References to "2023", or other years refer to the 12 months ended 30 June of that year.

$: Australian dollars unless specified otherwise
AASB: Australian Accounting Standards Board
ACCC: Australia Competition and Consumer Commission
AEMO: Australian Energy Market Operator
AGP: Athena gas plant
ANREO: accelerated, non-renounceable entitlement offer
bbls: barrels of oil
bbls/d: barrels of oil per day
CGU: cash generating unit
EBITDAX: earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment
EIP: equity incentive plan
FTE: full time equivalent
FVLCD: fair value less cost of disposal
GSA: gas sales agreement
GST: goods and services taxes
HSE: health, safety and environment
HSEC: health, safety, environment and community
IFRS: International Financial Reporting Standards
JV: joint venture
JOA: joint operating agreement
kbbl: thousand barrels of oil
LNG: liquified natural gas
LTI: lost time injury
Mitsui: Mitsui E&P Australia and its associated entities
MMbbl: million barrels of oil
MMboe: million barrels of oil equivalent
OGPP: Orbost gas processing plant
Pertamina: PT Pertamina Hulu Energi
PJ: petajoules
PJe: petajoules-equivalent
PRRT: Petroleum resource rent tax
STIP: short-term incentive plan
TJ: terajoules
TJ/d: terajoules per day
TRIFR: total recordable injury frequency rate
US: United States
2P: best estimate of reserves.
The sum of proved plus probable reserves
2C: best estimate of contingent resources

CORPORATE DIRECTORY

DIRECTORS

John C Conde AO, Chairman
Jane L Norman, Managing Director
Timothy G Bednall
Giselle M Collins
Elizabeth A Donaghey
Jeffrey W Schneider

COMPANY SECRETARY

Nicole Ortigosa

REGISTERED OFFICE AND BUSINESS ADDRESS

Level 8, 70 Franklin Street
Adelaide, South Australia 5000
Telephone: +618 8100 4900
Facsimile: +618 8100 4997
Email: customerservice@cooperenergy.com.au
Website: www.cooperenergy.com.au

AUDITORS

Ernst & Young
121 King William Street
Adelaide, South Australia 5000

SHARE REGISTRY

Computershare Investor Services Pty Limited
Level 5,115 Grenfell Street
Adelaide, South Australia 5000
Website: investorcentre.com/au

Telephone
Australia 1300 556 161
International +61 3 9415 4000
Facsimile +61 3 9473 2500

COOPER ENERGY