COOPER ENERGY LIMITED

and its controlled entities

ABN 93 096 170 295

HALF-YEAR FINANCIAL REPORT

31 December 2023

Appendix 4D
Interim Financial Report

Cooper Energy Limited		
ABN 93 096 170 295	Report ending Corresponding period	31 December 2023 31 December 2022

Results for announcement to the market

	Percentage Change %	**Amount A$'000 Dec 23**	Amount A$'000 Dec 22 (Restated)
Revenue from ordinary activities	5%	**105,864**	101,233
Total loss for the period attributable to members	2,062%	**(90,757)**	(4,198)
Net tangible assets per share (inclusive of exploration and development expenditure capitalised)		**16.4 cents**	20.8 cents

The Directors do not propose to pay a dividend.
The attached Financial Report has been reviewed.

Review and Results of Operations

The attached Operating and Financial Review provides further information and explanation.

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Operations

Cooper Energy Limited ("Cooper Energy" or the "Company") generates revenue from the production of gas and liquids from the Gippsland and Otway basins, and production of oil from the Cooper Basin. The Company's current operations and interests include:

- offshore gas and liquids production in the Gippsland Basin, Victoria, from the Sole gas field;
- offshore gas and 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/Eromanga Basin, South Australia;
- the Orbost Gas Processing Plant ("OGPP") located near the town of Orbost in Eastern Victoria;
- the Athena Gas Plant ("AGP") located near Port Campbell in Western Victoria;
- the Manta gas and liquids field in the offshore Gippsland Basin;
- the Annie gas discovery in the offshore Otway Basin; and
- exploration and appraisal prospects in the Otway, Gippsland and Cooper/Eromanga basins.

The Company is the operator of all its offshore exploration and production gas activities as well as onshore processing at OGPP and AGP.

Workforce

At 31 December 2023, the Company had 124.1 full time equivalent ("FTE") employees and 26.0 FTE contractors, compared with 128.9 FTE employees and 24.4 FTE contractors at 30 June 2023. Contractors are engaged via third parties in South Australia, Western Australia and Victoria. Contractor numbers fluctuate in line with project requirements.

Health, safety and environment

One lost time injury was recorded during H1 FY24. On 3 November 2023, an operator suffered a hand laceration whilst performing maintenance activities which required medical treatment. The operator has since returned to work having made a full recovery.

There were no Tier 1 or Tier 2[1] process safety events, and no reportable (onshore) or recordable (offshore) environmental incidents during H1 FY24.

Sustainability

A mixture of Australian Carbon Credit Units and Climate Active eligible international credits were retired in December 2023 and January 2024 to offset the Company's estimated H1 FY24 scope 1, scope 2 and relevant scope 3 emissions[2].

Production

H1 FY24 gas and oil production was 60.8 TJe/d, or 11.2 PJe (1.83 MMboe) for the half, a record for the Company and 0.5% higher than H1 FY23 production of 60.5 TJe/d or 11.1 PJe (1.82 MMboe).

In December 2023, a four-day planned maintenance shutdown impacted production at OGPP. Excluding this event, H1 FY24 gas and oil production was 61.7 TJe/d, up 1% on H1 FY23.

In the Gippsland Basin, H1 FY24 Sole gas production of 47.4 TJ/d or 8.7 PJ, was similar to H1 FY23 of 47.5 TJ/d or 8.7 PJ. Excluding the planned December shutdown, Sole production for H1 FY24 was 48.5 TJ/d, up 2% from H1 FY23.

In February 2024, subsequent to the half end, a 12-day production record was set at OGPP, with the plant averaging 62.8 TJ/d during that particular 12-day period between absorber cleans. For the 60-day period ending on the same day in February, a record was also set, with the plant averaging 55.2 TJ/d during that time.

In the Otway Basin, improved plant stability and reliability at AGP helped keep gas production steady at 11.2 TJe/d or 2.0 PJe for the half, in line with H1 FY23 production (net to Cooper Energy's 50% share).

Crude oil production from the Company's non-operated Cooper Basin assets was 68.4 kbbl, up 25% from 54.9 kbbl in H1 FY23 (net to Cooper Energy's 25% share). The increased oil production is mainly due to the connection of three new wells, Rincon-4, Callawonga-23 and Bangalee South-1, which came online in June (prior to this half), July and December 2023, respectively.

With strong second quarter OGPP performance, and stable production from AGP and PEL 92 for the half overall, total production for H1 FY24 of 60.8 TJe/d is tracking within full year FY24 guidance of 58.5 – 65.2 TJe/d.

Orbost Improvement Project

Work continued on the Orbost Improvement Project during the half, with focus on improving processing rates by minimising foaming and fouling where possible, as well as reducing absorber bed clean times.

[1] Release of material greater than the threshold quantities described in table 1 or 2 of API Recommended Practice 754 in any one hour period
[2] See page 15 of Cooper Energy 2023 Sustainability Report for scope definitions

Recent workstreams have included reinstatement of the polisher unit, installation of alternative packing material in the absorber beds, optimisation of the 'nutrimix' solution, trialling in-situ washing of the absorber beds, and installation of an alternate design spray distributer in the absorber beds.

Reinstatement of the polishing unit in late December was a positive outcome, driving improved performance with a new type of polisher media loaded that is tolerant to free water, and has been selected to maximise longevity between changeouts. Performance to date suggests the new media is fit for the requirements of the gas stream. For those workstreams that have not yielded material positive outcomes, including those in Q1 FY24, learnings from that work have been embedded in OGPP operations.

Trials of in-situ absorber bed washing continued subsequent to half end, along with other workstreams under the Orbost Improvement Project. If successful, in-situ washing will further reduce the absorber bed downtime and reduce the operational intensity associated with the current vessel entry cleaning process.

As announced at the FY23 full year results, work is progressing on the option for a third absorber bed if the Orbost Improvement Project workstreams do not deliver sufficient sustained higher rates.

BMG wells decommissioning

The Helix Q7000 intervention vessel is currently on site at BMG, progressing through the decommissioning programme.

Following extended delays in the vessel's work programme in New Zealand, the Q7000 departed the Taranaki Basin in late November 2023 and after loading of equipment and fuel, arrived at the BMG site in late December.

The late arrival of the Q7000 at the BMG field resulted in the Company incurring more than three months of holding costs for the remaining contractor spread on the BMG programme.

This delayed start, together with the additional time required for startup activities, and initial work slower than expected at the Basker 3 well, have led to a reforecast of the total mid-case cost estimate. The Company revised its mid-case cost estimate for the BMG wells decommissioning to approximately A$240-280 million, inclusive of low FX rates and including reasonable contingency for future non-productive time and waiting on weather[3].

During the remainder of the programme, where possible, Cooper Energy and its contractors continue to pursue savings to offset increased costs, including implementing operational learnings and efficiencies and simplifying the scope of decommissioning.

Based on the updated mid-case estimate, the BMG wells decommissioning programme is expected to be completed in early May 2024. The remaining BMG decommissioning scope, including removal of subsea manifolds, umbilicals, flowlines and any other remaining equipment, is expected to be undertaken by the end of 2026 and is included in the non-current restoration provision.

Transformation programme

Another of the Company's key priorities for FY24 is the cost-out initiatives under the transformation programme, outlined during the FY23 full year results. The transformation programme is all encompassing, targeting savings and efficiency across the entire business, including a minimum 10% saving in G&A.

Over 90 initiatives have been identified across the business, with 19 initiatives completed or actioned so far. Around 85% of the identified initiatives are targeted to be completed or actioned by the end of FY24, with the full effect of cost savings and benefits realised into FY25 and beyond.

Significant savings are being targeted in production costs across the business, but in particular at OGPP where the greatest cost-out opportunities reside. Some savings have already been realised in relation 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 significant further savings in this area.

An additional focus area at OGPP concerns the reduction of waste costs arising from the removal 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 in savings.

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.

[3] See further ASX announcement on 22 January 2024. Refer also to the revised FY24 capex guidance later in this report.

To date, approximately A$2.0 million in G&A net savings has been realised, relative to H2 FY23, as a result of a freeze in salary rises, reduction in the size of the Board, reduction in the number of KMP, scope rationalisation and reduction in use of advisory services, and reductions to travel and entertainment wherever possible. This savings number is net of A$2.0 million of restructuring costs and other H2 FY23 non-recurring items, hence we expect to see a further significant reduction in reported G&A in FY25.

These changes are targeted at right-sizing the business for our current position in the Company's evolution, as well as recognising where Cooper Energy sits in relation to our peer group. Further initiatives in reviewing structure and office rationalisation, post BMG wells decommissioning, target further savings in excess of A$1.0 million in FY25.

Further updates on the transformation programme will be provided through the remainder of the financial year.

Commercial

Key commercial activities during H1 FY24 are summarised below.

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[4].

During December 2023, the Company completed a price review on the one petajoule per annum Visy Glass 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.

PEP 169 acquisition
In October 2023 Cooper Energy and Lakes Blue Energy agreed to binding terms, including an exclusivity period, to negotiate the remaining aspects of Cooper Energy's acquisition of a 25.1% participating interest in PEP 169.

The proposed transaction comprises:

- Cooper Energy acquiring 51% of the shares and a controlling interest in a newly formed subsidiary of Lakes Blue Energy that has been specifically set up to hold Lakes Blue Energy's 49% interest in PEP169; and
- Cooper Energy providing an upfront payment of A$1.2 million, together with funding Lakes Blue Energy's retained 23.9% working interest of the drilling costs of Enterprise North-1, capped at A$1.25 million.

While the exclusivity arrangements continue in place, the transaction remains conditional on finalisation of transaction documents and obtaining necessary consents and regulatory approvals.

PEP 169 is located in the onshore Otway Basin, Victoria. The PEP 169 Enterprise North prospect is located less than three kilometres from the Cooper Energy operated AGP, which has ~150 TJ/d of total processing capacity and current utilisation of ~25 TJ/d (both 100% gross).

Exploration, appraisal, and development

<u>Gippsland Basin (offshore, except where noted)</u>

Cooper Energy is the operator and 100% interest holder for all of its Gippsland Basin interests. As at 31 December 2023, these interests comprised:

a) VIC/L32, which contains the Sole gas field;
b) VIC/RL13, VIC/RL14 and VIC/RL15, which contain the Manta gas and liquids field. 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;
d) exploration permits VIC/P72, VIC/P75 and VIC/P80; and
e) a 100% interest in and operatorship of the OGPP (onshore Victoria).

Exploration
An update was provided to the ASX on 15 May 2023 on the Prospective Resource potential at the Manta Hub in retention licences VIC/RL13, 14 and 15, and exploration permit VIC/P80. The combined mean unrisked Prospective Resource potential from Manta Deep, Gummy Deep (VIC/RL13), Chimaera East (VIC/RL15) and Wobbegong (VIC/P80) is 1.3 Tcf of natural gas and 30 MMbbl of condensate. VIC/P80 seismic mapping is ongoing, focusing on additional prospectivity in the block.

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

Otway Basin (offshore, except where noted)
The Company's interests in the offshore Otway Basin as at 31 December 2023 comprised:

a) a 50% interest in and operatorship of production licences VIC/L24 and VIC/L30 containing the 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 the Martha gas field and part of the Black Watch gas field, 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 the Athena Gas Plant (onshore Victoria) which is jointly owned with Mitsui and processes gas from the Casino, Henry and Netherby fields; and
f) a 10% non-operated interest in production licence VIC/L22 which holds the shut-in Minerva gas field, with Woodside the operator and 90% interest holder.

Exploration
Work continued during H1 FY24 to progress drilling options for testing the gas potential of these exploration prospects in conjunction with Otway Phase 3 Development ("OP3D"), the next phase of the Company's development of the offshore Otway portfolio, discussed further below.

A Prospective Resource update for six prospects (Elanora, Heera, Isabella, Juliet, Nestor and Pecten East) was announced to the ASX in February 2022. These prospects all show strong seismic amplitude support for the presence of gas and are located close to existing production infrastructure. Importantly, there has been a total of 17 exploration wells drilled (across all operators) in the offshore Otway Basin to date, with seismic amplitude support, of which 16 have been successful.

Development: Otway Phase 3 Development
Cooper Energy has continued to progress the OP3D project and has secured the Transocean Equinox rig, as part of a consortium agreement with three other operators. The contract is expected to commence during FY26, with Cooper Energy committed to one firm well, with options to drill additional subsea development and/or exploration/appraisal wells.

The OP3D project is positioned to proceed to sanction as soon as conditions permit, most particularly Otway joint venture partner support, substantial progress of the BMG wells decommissioning programme, and improved performance at OGPP as a result of the Orbost Improvement Project.

Otway growth is expected to be funded from organic cash generation, supported by existing committed senior secured bank debt as well as the up to A$120 million accordion debt facility. The Company is also encouraged to see significant ongoing interest from a number of gas customers to support new domestic gas supply through a range of funding options, which could include prepayments.

Growth in the Otway provides the opportunity to tie back new resources to Cooper Energy's existing gas processing infrastructure at AGP, which has ~150 TJ/d of total processing capacity and current utilisation of ~25 TJ/d (both 100% gross).

Otway Basin (onshore)
The Company's interests in the onshore Otway Basin as at 31 December 2023 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 Limited;
b) a 50% interest in PEP 168 in Victoria, with the remaining interest held by the operator, Beach Energy Limited; and
c) a 75% interest in PEP 171 in Victoria, with the remaining interest held by Vintage Energy Limited.

Exploration
Processing of the PEL 494 Dombey 3D seismic survey has been completed during the first half of FY24, following acquisition of the data in FY22. Interpretation of the 3D seismic data is expected to be completed during 2024 and will delineate the resource potential of the Dombey gas field and identify potential new exploration opportunities.

In PEP 168, several legacy 3D seismic datasets have been reprocessed during the first half of FY24 to form one survey. Interpretation of this reprocessed seismic will be undertaken during H2 FY24, to further mature drilling prospects in the permit.

Cooper Basin
The Company's interests in the Cooper Basin as at 31 December 2023 comprised a 25% interest in PRLs 85-104 (ex PEL 92), with the remaining 75% interest held by the operator, Beach Energy Limited.

Exploration and development
During the half, an exploration drilling campaign was completed in ex PEL 92, with Cooper Energy participating in four wells. The Bangalee South-1 exploration well 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 Birkhead zone was brought online in December 2023, and at calendar year end the average production was approximately 300 bbls/d.

Wooley Rock-1 intersected 1.2 metres of net pay and was plugged and abandoned as a non-commercial discovery. Chadinga-1 and Marion-1 were plugged and abandoned having failed to encounter hydrocarbons.

Other events

Scheduled annual re-determination

In December 2023 the Company achieved a positive outcome from the scheduled annual re-determination of the so-called banking case under Cooper Energy's A$400 million senior secured bank loan.

The positive outcome was partly due to increases in assumed contracted and spot gas prices, and to improved assumed processing rates at OGPP.

As a result, the assessed borrowing base under the banking group's assumptions has increased, providing greater funding flexibility over the life of the loan. The redetermination results reinforce the strong support which the Company continues to receive from its lending group.

FY24 capex guidance

In August 2023 as part of the FY23 full year results[5], the Company provided FY24 guidance for capex[6], along with production and production expenses[7].

Capex guidance has increased in line with the revised BMG wells decommissioning mid-case cost estimate announced to the ASX on 22 January 2024, which dominates this year's capex programme. That is, FY24 capex guidance is A$240 – 280 million.

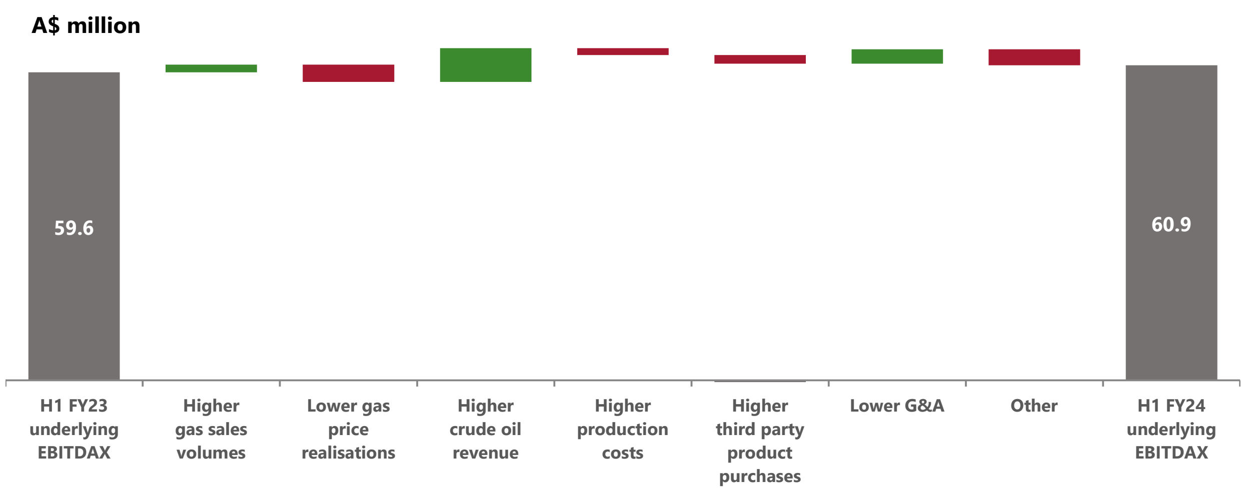
Financial Performance

All numbers in tables in the Operating and Financial Review have been rounded and are expressed in Australian dollars, except where noted otherwise[8].

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 H1 FY24 underlying EBITDAX of A$60.9 million, a 2% increase from H1 FY23 underlying EBITDAX of A$59.6 million.



[5] For further information see ASX release 29 August 2023
[6] Capital expenditure guidance includes stay in business capex and BMG wells decommissioning costs
[7] Production expenses comprise labour, materials, transport, overheads, insurance, license costs, JV management and carbon offset costs, but excludes third-party product purchases and trading costs, royalties and non-cash depreciation and amortisation
[8] Some total figures may differ insignificantly from totals obtained from the arithmetic addition of the rounded numbers presented

Factors which contributed to the movement in underlying EBITDAX between the periods included:

- higher gas volumes sold compared to the previous half;
- lower gas sales revenue of A$1.9 million attributed to lower realised gas prices across the portfolio (A$8.44/GJ H1 FY24, versus A$8.75/GJ H1 FY23). While spot volumes sold were higher (1.2PJ H1 FY24 versus 0.5PJ H1 FY23), realised spot prices were lower (A$9.92/GJ H1 FY24, versus A$17.12/GJ H1 FY23);
- higher oil sale revenue of A$6.5 million driven by higher volumes of oil liftings;
- higher production expenses of A$1.3 million in H1 FY24 due to PEL 92 inventory movement as a result of higher oil sales;
- third-party product purchases and trading costs were higher by A$1.7 million in H1 FY24, due to the timing of purchases to fulfill contracted sales in Q1 FY24. Production was lower in that quarter, versus Q1 FY23, because of performance improvement initiatives that were not successful;
- lower G&A of A$2.8 million in H1 FY24 linked to savings realised from the transformation programme;
- other items were higher by A$3.1 million including the impacts of currency translation.

First half production expenses of A$27.9 million (H1 FY23: A$26.2 million), inclusive of PEL 92 oil inventory movements, reflects the reduction in absorber downtime gas-to-gas and fewer polisher media change-outs at OGPP versus planned. Compared to H1 FY23, H1 FY24 reflects a full period of operating the OGPP with no toll payable to APA, while incurring more operating costs in addressing the sulphur depositional issues at OGPP as well as costs associated with the Performance Improvement Project.

Underlying profit after tax (exclusive of the items noted below) was A$5.4 million compared with an underlying loss after tax of A$1.2 million in H1 FY23. Factors driving the change in underlying profit, in addition to those listed above for underlying EBITDAX, included:

- higher net finance costs by A$1.8 million, mostly due to higher interest expense;
- lower accretion expense of A$0.4 million;
- lower amortisation and depreciation of A$0.7 million of gas and oil assets and property, plant and equipment;
- higher exploration and evaluation expense of A$2.4 million; and
- higher tax benefit of A$8.4 million.

The Company's statutory loss after tax was A$90.8 million for the six months to December 2023, which compares with a restated[9] loss after tax of A$4.2 million recorded in H1 FY23. The H1 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$96.2 million. These items comprise:

- non-cash restoration expense and associated costs of A$83.6 million resulting from a reassessment of the BMG wells decommissioning, Patricia Baleen and Minerva Field provisions;
- derecognition of the previously recognised deferred tax asset in respect of the Sole gas field decommissioning of A$33.5 million;
- hedging costs of A$1.5 million;
- OGPP acquisition and integration costs of A$0.3 million;
- business restructuring and transformation costs of A$3.3 million;
- other expense of A$0.8 million in respect of the National Oil & Gas Australia Pty Ltd Commonwealth Government levy; and
- tax impact of the above items of A$26.8 million.

Financial Performance		H1 FY24	H1 FY23	Change	%
Production volume	PJe	11.19	11.14	0.05	0%
Sales volume	PJe	11.65	11.14	0.51	5%
Revenue	A$ million	105.9	101.2	4.7	5%
Gross profit	A$ million	24.7	23.7	1.0	4%
Underlying EBITDAX*	A$ million	60.9	59.6	1.3	2%
Operating cash flow	A$ million	21.1	55.3	(34.2)	(62%)
Underlying profit/(loss) before tax	A$ million	1.1	(6.0)	7.1	118%
Underlying profit/(loss) after tax	A$ million	5.4	(1.2)	6.6	n/m
Reported loss after tax	A$ million	(90.8)	(4.2)[9]	(86.6)	n/m
Cash, other financial assets and investments^	A$ million	103.4	78.2^	25.2	32%

* Earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment

^ Compared to 30 June 2023 which is the relevant comparative balance

[9] The comparative statement of comprehensive income has been restated on adoption of the amendments made to AASB 112, refer to Note 2 Basis of preparation and accounting policies for further information.

Operating cashflows for the period were A$21.1 million in H1 FY24, compared to A$55.3 million in H1 FY23. The main line items for operating cashflow comprised:

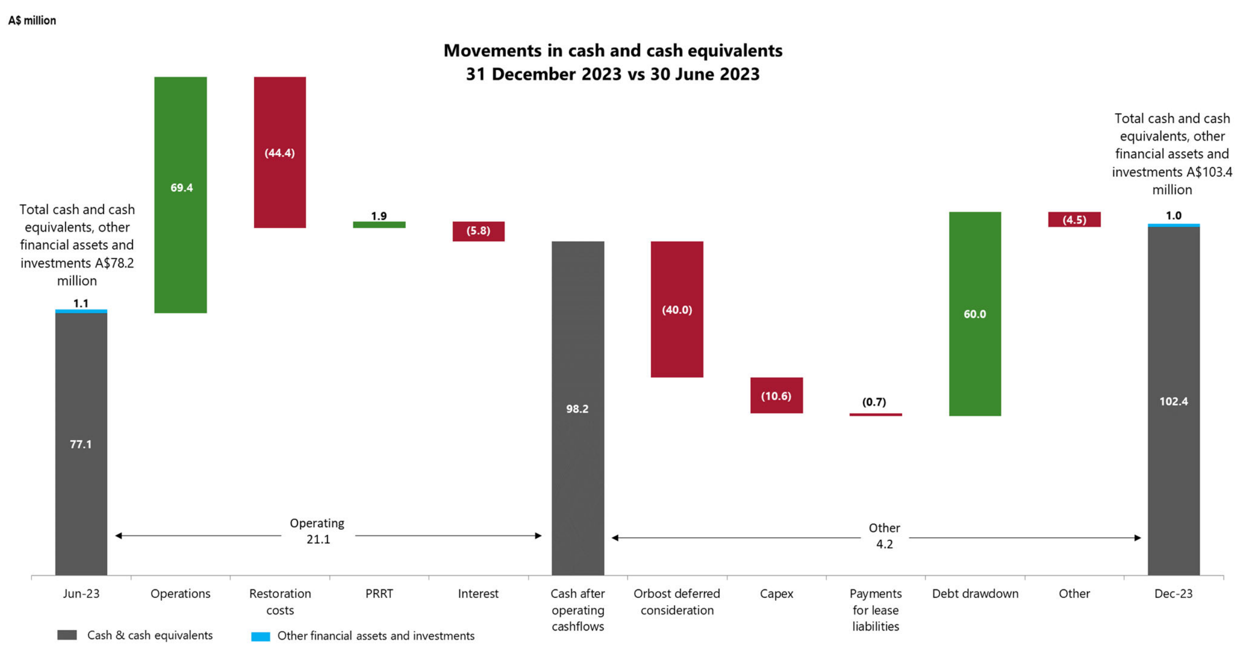
- cash generated from operations of A$69.4 million (H1 FY23: A$65.8 million);
- restoration costs of A$44.4 million (H1 FY23: A$3.4 million), up due to the commencement of the wells decommissioning activity at BMG;
- petroleum resource rent tax (PRRT) refund of A$1.9 million (H1 FY23: payments of A$3.9 million); and
- net interest paid of A$5.8 million (H1 FY23: A$3.1 million).

Excluding restoration spend and other non-recurring and non-underlying items, operating cash flow is A$70.6 million (H1 FY23: A$61.0 million).

Financing, investing and other cash inflows for the period were A$4.2 million (H1 FY23: A$214.0 million outflow, including net impact of OGPP acquisition of A$179.4 million) and primarily included:

- debt drawdown of A$60.0 million (H1 FY23: nil);
- OGPP deferred acquisition payment of A$40.0 million (H1 FY23: acquisition cost of A$210.0 million)
- capex spend of A$10.6 million on exploration, development and property, plant and equipment costs in relation to drilling in the Cooper Basin and spend on the Orbost Improvement Project (H1 FY23: A$12.8 million);
- nil proceeds from the equity issue (H1 FY23: A$57.6 million);
- nil proceeds from held for sale assets (H1 FY23: A$0.7 million);
- repayment of lease liability of A$0.7 million (H1 FY23: A$0.6 million);
- other including foreign exchange revaluation of A$4.5 million (H1 FY23: A$0.1 million).

Cash and cash equivalents increased by A$25.3 million over the period, as summarised in the chart below.



Financial Position

Financial Position		31 Dec 2023	30 Jun 2023 (restated)	Change	%
Total assets	A$ million	1,347.9	1,365.0	(17.1)	(1%)
Total liabilities	A$ million	908.6	836.5	72.1	9%
Total equity	A$ million	439.3	528.5	(89.2)	(17%)
Net debt	A$ million	(115.6)	(80.9)	(34.7)	43%

Total assets
Total assets decreased by A$17.1 million from A$1,365.0 million at 30 June 2023 to A$1,347.9 million at 31 December 2023.

At 31 December 2023, the Company held cash and cash equivalents of A$102.4 million and investments of A$1.0 million.

Gas and oil assets decreased by A$26.1 million from A$535.8 million to A$509.7 million, mainly as a result of amortisation driven by production during the period, partially offset by the transfer of the Bangalee South-1 exploration well from exploration and evaluation assets.

Total liabilities
Total liabilities increased by A$72.1 million from A$836.5 million at 30 June 2023 to A$908.6 million at 31 December 2023. Provisions increased by A$21.0 million from A$583.6 million to A$604.6 million, primarily driven by the reassessment of the BMG wells decommissioning costs, partially offset by spend in H1 FY24.

Total equity
Total equity decreased by A$89.2 million from A$528.5 million to A$439.3 million. In comparing equity at 31 December 2023 to 30 June 2023, the key movements were:

- higher accumulated losses of A$90.8 million due to the statutory loss for the period, including the significant items considered to fall outside underlying operating performance and described above;
- higher contributed equity of A$2.2 million due to vesting of performance rights during the period;
- lower reserves of A$0.6 million due to transfer of vested rights offset by share based payments issued in the period.

Strategy & outlook

Cooper Energy remains focused on playing our part in Australia's energy future, by exploring, developing and producing much-needed gas for Australian homes and businesses.

Gas is critical to the Australian economy and represents 27% of primary energy demand nationally[10]. New gas supply is urgently needed in Eastern Australia to meet ongoing demand to heat our homes, manufacture goods such as cement, glass and paper, as a feedstock for fertilisers and to generate flexible, firming power to support the growing integration of renewables.

While gas-fired power generation only represents approximately 5% of power produced in the National Electricity Market today, South Australia provides a window into the future. With approximately 70% of South Australia's power coming from renewables, gas makes up almost 25% of power consumed in the state, providing the backup when it is needed[11].

Cooper Energy is committed to supplying gas for domestic use and playing our part in enabling the energy transition. As existing sources of gas supply decline, as forecast by the Australian Energy Market Operator ("AEMO")[12], new domestic gas supply is the lowest cost and lowest emission gas that also strengthens energy security and creates local jobs. This is especially true in Cooper Energy's growth prospects, which are in established basins close to key markets, and feeding into existing, brownfield infrastructure. Without new domestic gas supply, Eastern Australia may require LNG imports and potentially face an up to 160% increase in contract prices, compared to 2023[13], along with higher emissions and less energy security.

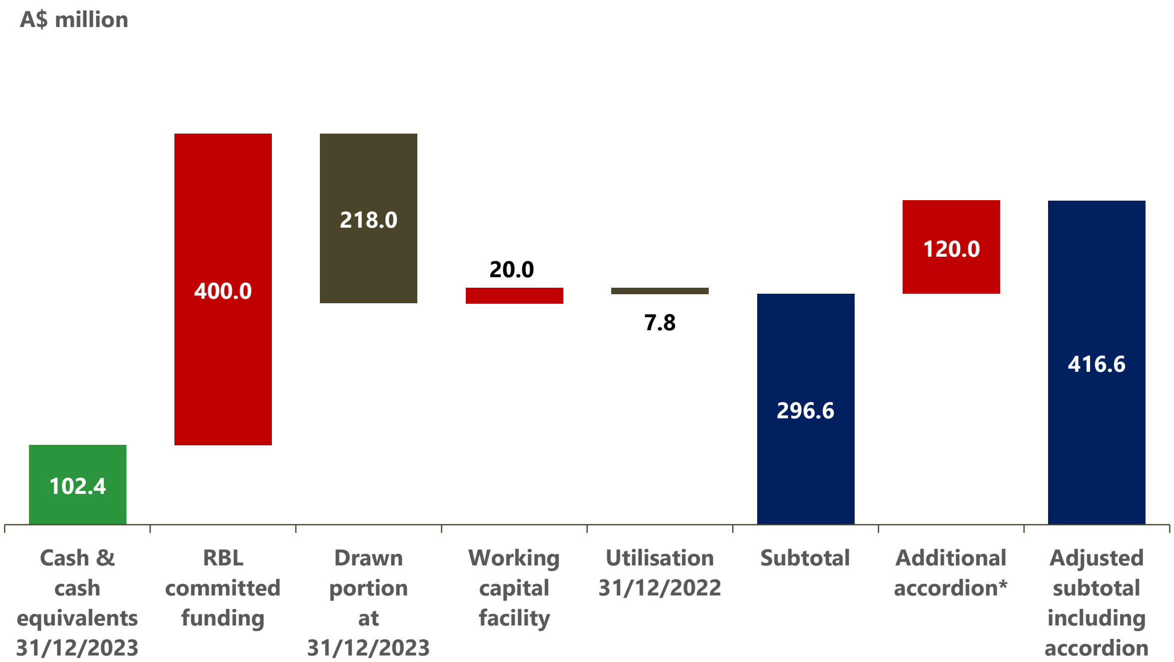
Cooper Energy has growth prospects in both the Otway and Gippsland Basins in Victoria, the two basins which are currently the largest suppliers of domestic gas in Eastern Australia. Our Otway growth project has the potential to provide up to 17% of Victoria's forecast gas consumption before 2030[14], with approximately 65 PJ of 2C resources and 585 Bcf of Prospective gas Resources on a gross basis[15]. The Company's latest assessment of its Gippsland Basin acreage shows a mean unrisked prospective resource potential of 1,300 Bcf of natural gas and 30 million barrels of condensate[16]. Developing this resource through our existing processing plants in Port Campbell and Orbost are the centrepieces of our growth strategy.

As more gas will be needed to support daily peaks in firming power, we see the shape of gas demand changing. Therefore, we are also exploring opportunities in gas storage, utilising our existing reservoirs, processing facilities and transport arrangements to ensure that our gas is delivered to customers when it is needed.

[10] Australian Energy Statistics 2022 Table C.
[11] Cooper Energy analysis of OpenNEM data.
[12] AEMO, 2023 Victorian Gas Planning Report; 2023 AEMO Gas Statement of Opportunities.
[13] Cooper Energy analysis of contract pricing data from ACCC and EnergyQuest.
[14] Cooper Energy analysis of 2023 AEMO Gas Statement of Opportunities.
[15] Annie 2C resource included as part of the Otway Basin 2C number in the FY23 Reserves and Contingent Resources ASX release on the 25 August 2023. Prospective Resources of the unrisked volume estimated to be recoverable from the prospect attributable to the Cooper Energy joint venture interest. The estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations. Mean Prospective Resource for the Otway prospects were announced to the ASX on 9 February 2022.
[16] Prospective Resources of the unrisked volume estimated to be recoverable from the prospect attributable to the Cooper Energy joint venture interest. The estimated quantities of petroleum that may be potentially recovered by the application of future development project(s) relate to undiscovered accumulations. Prospective resources for Gummy Deep, Manta Deep, Chimaera East and Wobbegong were announced to the ASX on 15 May 2023.

Funding and capital management

At 31 December 2023, the Company had cash reserves of A$102.4 million and drawn debt of A$218.0 million. The Company has a reserves based lending bank debt facility with a committed limit of A$400.0 million (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 BMG wells decommissioning project as well as a portion of the planned OP3D development 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$7.8 million has been utilised in respect of bank guarantees as at 31 December 2023. 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 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.

Risk Management

Cooper Energy manages risks in accordance with its risk management process with the objective of ensuring risks inherent in gas and oil exploration and production are identified, measured and managed to be kept as low as reasonably practicable. The Executive Leadership Team performs risk reviews on a regular basis and a summary is reported to the Risk and Sustainability Committee.

Reconciliations for net loss to underlying net loss and underlying EBITDAX

Reconciliation to underlying EBITDAX[17]		H1 FY24	H1 FY23	Change	%
Underlying profit / (loss)	A$ million	5.4	(1.2)	6.6	n/m
Add back:					
Tax impact of underlying adjustments	A$ million	(6.7)	2.2	(8.9)	n/m
Net finance costs	A$ million	6.8	5.0	1.8	36%
Accretion expense	A$ million	8.7	9.1	(0.4)	(4%)
Tax benefit	A$ million	(4.3)	(4.8)	0.5	10%
Depreciation	A$ million	19.7	18.5	1.2	6%
Amortisation	A$ million	28.9	30.8	(1.9)	(6%)
Exploration and evaluation expense	A$ million	2.4	-	2.4	100%
Underlying EBITDAX*	A$ million	60.9	59.6	1.3	2%

Reconciliation to underlying profit / (loss)		H1 FY24	H1 FY23	Change	%
Net loss after income tax	A$ million	(90.8)	(4.2)	(86.6)	n/m
Adjusted for:					
OGPP reconfiguration and commissioning works	A$ million	-	0.4	(0.4)	(100%)
OGPP acquisition and integration costs	A$ million	0.3	1.9	(1.6)	(84%)
Hedging costs	A$ million	1.5	-	1.5	100%
Restoration expense and associated costs	A$ million	83.6	4.0	79.6	n/m
NOGA levy	A$ million	0.8	1.0	(0.2)	(20%)
Business restructuring and transformation	A$ million	3.3	-	3.3	100%
Derecognition of income tax deferred tax asset	A$ million	33.5	-	33.5	100%
AASB 112 retrospective change	A$ million	-	(2.1)	2.1	100%
Tax impact of underlying adjustments	A$ million	(26.8)	(2.2)	(24.6)	n/m
Underlying profit / (loss)	A$ million	5.4	(1.2)	6.6	n/m

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

Directors' Report
For the half-year ended 31 December 2023

The Directors of Cooper Energy Limited ("the Company" or "Cooper Energy") present their report and the consolidated Financial Report for the half-year ended 31 December 2023. The dollar figures are expressed in Australian currency and to the nearest thousand unless otherwise indicated.

Directors

The names of the Directors in office during the half-year and as of the date of this report are:

John C Conde AO (Non-Executive Chairman)
Jane L Norman (Managing Director)
Timothy G Bednall (Non-Executive Director)
Giselle M Collins (Non-Executive Director)
Elizabeth A Donaghey (Non-Executive Director)
Jeffrey W Schneider (Non-Executive Director)

Victoria J Binns ceased to be a Director effective 9 November 2023.

Principal Activities

The Company 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 half-year.

Review and Results of Operations

A review of the operations of the Company can be found in the Operating and Financial Review commencing on page 3.

Significant Events After the Balance Date

Refer to Note 15 of the Notes to the Consolidated Financial Statements.

Auditor's Independence Declaration

Cooper Energy has obtained an independence declaration from the auditors, Ernst & Young, which forms part of this report.

Rounding

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

Signed in accordance with a resolution of the directors.

John Conde

Mr John C Conde AO
Chairman

J Norman

Ms Jane L Norman
Managing Director & CEO

27 February 2024

Ernst & Young
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Building a better working world

Auditor's Independence Declaration to the Directors of Cooper Energy Limited

As lead auditor for the review of the half-year financial report of Cooper Energy Limited for the half-year ended 31 December 2023, 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 review;

b) no contraventions of any applicable code of professional conduct in relation to the review; and

c) no non-audit services provided that contravene any applicable code of professional conduct in relation to the review.

This declaration is in respect of Cooper Energy Limited and the entities it controlled during the financial period.

Ernst & Young

Darryn Hall
Partner
Adelaide
27 February 2024

Consolidated Statement of Comprehensive Income

For the half-year ended 31 December 2023

	Notes	31 December 2023 $'000	31 December 2022 (Restated) $'000
Revenue from gas and oil sales	4	**105,864**	101,233
Cost of sales	4	**(81,182)**	(77,516)
Gross profit		**24,682**	23,717
Other expenses	4	**(104,272)**	(20,687)
Finance income	12	**2,031**	1,307
Finance costs	12	**(17,526)**	(15,399)
Loss before tax		**(95,085)**	(11,062)
Income tax expense	5	**(9,313)**	(1,050)
Petroleum resource rent tax benefit	5	**13,641**	7,914
Total tax benefit		**4,328**	6,864
Loss after tax		**(90,757)**	(4,198)
Other comprehensive income/(expenditure)			
Items that will not be reclassified subsequently to profit or loss			
Fair value movement on equity instruments at fair value through other comprehensive income		**(178)**	329
Other comprehensive income/(expenditure) for the period net of tax		**(178)**	329
Total comprehensive loss for the period attributable to shareholders		**(90,935)**	(3,869)
		Cents	Cents
Basic loss per share		**(3.4)**	(0.2)
Diluted loss per share		**(3.4)**	(0.2)

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

Consolidated Statement of Financial Position

As at 31 December 2023

	Notes	31 December 2023 $'000	30 June 2023 (restated) $'000
Assets			
Current Assets			
Cash and cash equivalents		**102,376**	77,134
Trade and other receivables		**23,552**	28,797
Prepayments		**8,770**	6,303
Inventory		**1,320**	2,182
Total Current Assets		**136,018**	114,416
Non-Current Assets			
Other financial assets	14	**954**	1,131
Contract asset		**2,228**	2,323
Intangible assets		**426**	967
Right-of-use assets		**6,810**	7,448
Exploration and evaluation assets	7	**185,154**	184,569
Property, plant and equipment	6	**365,153**	380,375
Gas and oil assets	8	**509,663**	535,842
Deferred tax asset		**75,420**	84,733
Deferred petroleum resource rent tax asset		**66,076**	53,167
Total Non-Current Assets		**1,211,884**	1,250,555
Total Assets		**1,347,902**	1,364,971
Liabilities			
Current Liabilities			
Trade and other payables	9	**78,094**	68,679
Provisions	10	**177,531**	166,098
Lease liabilities		**1,524**	1,467
Total Current Liabilities		**257,149**	236,244
Non-Current Liabilities			
Trade and other payables	9	**-**	19,262
Provisions	10	**427,087**	417,509
Lease liabilities		**8,420**	9,182
Interest bearing loans and borrowings	11	**204,927**	143,956
Other financial liabilities	14	**2,875**	2,853
Deferred petroleum resource rent tax liability		**8,178**	7,479
Total Non-Current Liabilities		**651,487**	600,241
Total Liabilities		**908,636**	836,485
Net Assets		**439,266**	528,486
Equity			
Contributed equity	13	**718,881**	716,726
Reserves		**25,453**	26,071
Accumulated losses		**(305,068)**	(214,311)
Total Equity		**439,266**	528,486

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

Consolidated Statement of Changes in Equity
For the half-year ended 31 December 2023

	Issued Capital $'000	Reserves $'000	Accumulated Losses $'000	Total Equity $'000
Balance at 1 July 2023	**716,726**	**26,071**	**(245,924)**	**496,873**
Impact of adoption of amendments to AASB 112 (Note 2)			**31,613**	**31,613**
Balance at 1 July 2023 (restated)	**716,726**	**26,071**	**(214,311)**	**528,486**
	-	-		
Loss for the period	**-**	**-**	**(90,757)**	**(90,757)**
Other comprehensive income	**-**	**(178)**	**-**	**(178)**
Total comprehensive loss for the period	**-**	**(178)**	**(90,757)**	**(90,935)**
Transactions with owners in their capacity as owners:				
Share based payments	**-**	**1,715**	**-**	**1,715**
Transferred to issued capital	**2,155**	**(2,155)**	**-**	**-**
Balance as at 31 December 2023	**718,881**	**25,453**	**(305,068)**	**439,266**
Balance at 1 July 2022	478,261	197,625	(177,461)	498,425
Impact of adoption of amendments to AASB 112 (Note 2)	-	-	23,642	23,642
Balance at 1 July 2022 (restated)	478,261	197,625	(153,819)	522,067
Loss for the period (restated) (Note 2)	-	-	(4,198)	(4,198)
Other comprehensive income	-	329	-	329
Total comprehensive gain/(loss) for the period (restated)	-	329	(4,198)	(3,869)
Transactions with owners in their capacity as owners:				
Equity issue	58,596	-	-	58,596
Share based payments	-	2,541	-	2,541
Transferred to issued capital	179,869	(179,869)	-	-
Balance as at 31 December 2022 (restated)	716,726	20,626	(158,017)	579,335

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

Consolidated Statement of Cash Flows
For the half-year ended 31 December 2023

	31 December 2023 $'000	31 December 2022 $'000
Cash Flows from Operating Activities		
Receipts from customers	**107,504**	108,584
Payments to suppliers and employees	**(38,132)**	(42,792)
Payments for restoration	**(44,364)**	(3,421)
Petroleum resource rent tax received/(paid)	**1,858**	(3,930)
Interest received	**2,104**	1,210
Interest paid	**(7,884)**	(4,337)
Net cash flows from operating activities	**21,086**	55,314
Cash Flows from Investing Activities		
Payments for property, plant and equipment	**(42,821)**	(242,911)
Payments for intangibles	**-**	(610)
Payments for exploration and evaluation	**(4,830)**	(12,324)
Payments for gas and oil assets	**(2,942)**	(723)
Proceeds from held for sale assets	**-**	650
Net cash flows used in investing activities	**(50,593)**	(255,918)
Cash Flows from Financing Activities		
Repayment of lease liabilities	**(704)**	(611)
Transaction costs associated with borrowings	**-**	(15,142)
Proceeds from equity issue	**-**	57,579
Proceeds from borrowings	**60,000**	158,000
Repayment of borrowings	**-**	(158,000)
Net cash flows from financing activities	**59,296**	41,826
Net (decrease)/increase in cash held	**29,789**	(158,778)
Net foreign exchange differences	**(4,547)**	93
Cash and cash equivalents at 1 July	**77,134**	247,012
Cash and cash equivalents at 31 December	**102,376**	88,327

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

1. Corporate information

The consolidated financial report of Cooper Energy Limited ("Cooper Energy" or "the Group") for the half year ended 31 December 2023 was authorised for issue on 27 February 2024 in accordance with a resolution of the Directors. Cooper Energy Limited is a company limited by shares, incorporated and domiciled in Australia 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' Report.

2. Basis of preparation and accounting policies

This interim financial report for the half-year ended 31 December 2023 has been prepared in accordance with AASB 134 *Interim Financial Reporting* and the Australian Corporations Act 2001.

The financial report is presented in Australian dollars and 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.

The half-year financial report does not include all notes of the type normally included within the annual financial report. It is recommended that the half-year financial report be read in conjunction with the annual financial report for the year ended 30 June 2023 and considered together with any public announcements made by Cooper Energy during the half-year ended 31 December 2023, in accordance with the continuous disclosure obligations of the ASX Listing Rules.

Accounting policies and methods of computation are the same as those adopted in the most recent annual financial report.

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 deductable 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.

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:

	31 December 2022 (Previously reported) $'000	Impact of AASB 112 amendments $'000	31 December 2022 (Restated) $'000
Consolidated Statement of Financial Position			
Assets: Deferred tax asset	66,184	(1,686)	64,498
Assets: Deferred petroleum resource rent tax asset	17,912	27,125	45,037
Liabilities: Deferred petroleum resource rent tax liability	(18,051)	257	(17,794)
Equity: Accumulated losses	(183,713)	25,696	(158,017)
Consolidated Statement of Comprehensive Income			
Income tax benefit/(expense)	1,603	(2,653)	(1,050)
Petroleum resource rent tax benefit	3,207	4,707	7,914

There was no material impact on the Consolidated Statement of Cash Flows, other comprehensive income, or on basic and diluted EPS.

Funding overview
The Group holds cash balances of $102.4 million and has drawn debt of $218.0 million as at the end of the reporting period with a further $182.0 million available and undrawn under a senior secured reserve based loan facility with an expected maturity date of September 2027. The Company also has a further $7.8 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
Existing cash reserves and forecast cash flows indicate the Company can fund its existing obligations, including the increased BMG wells decommissioning cost estimate (refer to note 10), for at least 12 months from the date of this report. It is the directors' view, having considered the matters set out above, that it is appropriate to prepare the financial statements on a going concern basis.

3. Segment Reporting

Identification of reportable segments and types of activities

The Group has identified its reportable segments to be Southeast Australia, Cooper Basin (based on the nature and geographic location of the assets) and Corporate. This forms the basis of internal Group reporting to the 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 Netherby 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 2023 Annual Financial Report.

3. Segment Reporting continued

The following table presents revenue and segment results for reportable segments:

	Southeast Australia $'000	Cooper Basin $'000	Corporate and Other $'000	Consolidated $'000
Half-year ended 31 December 2023				
Revenue from gas and oil sales	**93,838**	**12,026**	**-**	**105,864**
Total revenue	**93,838**	**12,026**	**-**	**105,864**
Segment result before interest, tax, depreciation, amortisation and impairment	**(22,817)**	**5,315**	**(13,521)**	**(31,023)**
Depreciation and amortisation	**(45,634)**	**(1,929)**	**(1,004)**	**(48,567)**
Net finance costs	**(8,954)**	**(181)**	**(6,360)**	**(15,495)**
Profit/(loss) before tax	**(77,405)**	**3,205**	**(20,885)**	**(95,085)**
Income tax benefit	**-**	**-**	**(9,313)**	**(9,313)**
Petroleum resource rent tax benefit	**13,641**	**-**	**-**	**13,641**
Net profit/(loss) after tax	**(63,764)**	**3,205**	**(30,198)**	**(90,757)**
Segment assets	**606,886**	**31,049**	**709,967**	**1,347,902**
Segment liabilities	**825,190**	**5,617**	**77,829**	**908,636**

	Southeast Australia $'000	Cooper Basin $'000	Corporate and Other $'000	Consolidated $'000
Half-year ended 31 December 2022 (restated)[1]				
Revenue from gas and oil sales	95,728	5,505	-	101,233
Total revenue	95,728	5,505	-	101,233
Segment result before interest, tax, depreciation, amortisation and impairment	60,682	3,727	(12,140)	52,269
Depreciation and amortisation	(46,632)	(981)	(1,626)	(49,239)
Net finance costs	(10,016)	(77)	(3,999)	(14,092)
Profit/(loss) before tax	4,034	2,669	(17,765)	(11,062)
Income tax benefit	-	-	(1,050)	(1,050)
Petroleum resource rent tax benefit	7,914	-	-	7,914
Net profit/(loss) after tax (Restated)	11,948	2,669	(18,815)	(4,198)
Segment assets	558,295	25,245	772,839	1,356,379
Segment liabilities	627,860	4,608	168,218	800,686

[1] Comparative information has been restated to reflect the adoption of narrow scope amendments to AASB 112 Income Taxes, refer to note 2 for details

4. Revenues and Expenses

	31 December 2023 $'000	31 December 2022 $'000
Revenue from gas and oil sales		
Revenue from contracts with customers		
Gas and gas liquids revenue	**93,838**	95,729
Oil revenue from contracts with customers	**12,026**	5,565
Total revenue from contracts with customers	**105,864**	101,294
Other revenue		
Fair value movement on receivables	**-**	(61)
Total other revenue	**-**	(61)
Total revenue from gas and oil sales	**105,864**	101,233
Cost of sales		
Production expenses	**(27,030)**	(26,926)
Royalties	**(901)**	(546)
Third-party product purchases and trading costs	**(4,887)**	(3,184)
Amortisation of gas and oil assets	**(28,803)**	(30,027)
Depreciation of property, plant and equipment	**(18,669)**	(17,583)
Inventory movement	**(892)**	750
Total cost of sales	**(81,182)**	(77,516)
Other expenses		
Selling expense	**(592)**	(130)
General administration	**(8,427)**	(8,617)
Depreciation of property, plant and equipment	**(366)**	(347)
Restoration expense	**(76,421)**	(4,003)
Amortisation of intangibles	**(91)**	(730)
Depreciation of right-of-use assets	**(638)**	(552)
Care and maintenance	**(1,787)**	(1,009)
Exploration and evaluation expense	**(2,403)**	-
OGPP reconfiguration and commissioning works	**-**	(446)
Other (including new ventures)	**(13,547)**	(4,853)
Total other expenses	**(104,272)**	(20,687)
Employee benefits expense included in general administration		
Director and employee benefits	**(18,050)**	(13,277)
Share based payments	**(1,715)**	(2,541)
Superannuation expense	**(1,411)**	(1,117)
Total employee benefits expense (gross)	**(21,176)**	(16,935)

5. Income Tax Expense

The major components of income tax expense are:

	31 December 2023 $'000	31 December 2022 (restated) $'000
Consolidated Statement of Comprehensive Income		
Deferred income tax		
Origination and reversal of temporary differences	**(33,628)**	(6,000)
Recognition of losses	**24,315**	4,950
Income tax expense	**(9,313)**	(1,050)
Current petroleum resource rent tax		
Current year	**1,431**	(3,009)
	1,431	(3,009)
Deferred petroleum resource rent tax		
Origination and reversal of temporary differences	**12,210**	10,923
	12,210	10,923
Total petroleum resource rent tax benefit	**13,641**	7,914
Total tax benefit	**4,328**	6,864
Numerical reconciliation between tax expense and pre-tax net profit		
Accounting loss before income tax	**(95,085)**	(11,062)
Income tax using the domestic corporation tax rate of 30% (H1 FY23: 30%)	**28,526**	3,319
(Increase)/decrease in income tax expense due to:		
Non-assessable income/non-deductible (expenditure)	**(709)**	(796)
Other	**(33,595)**	(20)
Recognition of royalty related income tax benefits	**(3,535)**	(3,553)
Total income tax expense	**(9,313)**	(1,050)
Petroleum resource rent tax benefit	**13,641**	7,914
Total tax benefit	**4,328**	6,864

6. Property, plant and equipment

31 December 2023, $'000	**Production assets**	**Corporate assets**	**Total**
Reconciliation of carrying amounts at beginning and end of period:			
Carrying amount at beginning of period	**377,382**	**2,993**	**380,375**
Additions	**3,595**	**218**	**3,813**
Depreciation	**(18,669)**	**(366)**	**(19,035)**
Carrying amount at end of period	**362,308**	**2,845**	**365,153**
Cost	**423,212**	**8,332**	**431,544**
Accumulated depreciation	**(60,904)**	**(5,487)**	**(66,391)**
Total	**362,308**	**2,845**	**365,153**

7. Exploration and evaluation assets

	31 December 2023 $'000
Reconciliation of carrying amounts at beginning and end of period:	
Carrying amount at beginning of period	**184,569**
Additions	**4,151**
Exploration and evaluation expense	**(2,403)**
Transferred to gas and oil assets	**(1,163)**
Carrying amount at end of period	**185,154**

During the half-year the Group's exploration assets were assessed for impairment indicators in accordance with AASB 6 *Exploration for and Evaluation of Mineral Resources*. There were no indicators of impairment identified. No impairment expense was recognised.

8. Gas and oil assets

	31 December 2023 $'000
Reconciliation of carrying amounts at beginning and end of period:	
Carrying amount at beginning of period	**535,842**
Additions	**1,461**
Transferred from exploration and evaluation	**1,163**
Amortisation	**(28,803)**
Carrying amount at end of period	**509,663**
Cost	**842,522**
Accumulated amortisation & impairment	**(332,859)**
Total	**509,663**

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

9. Trade payables

	31 December 2023 $'000	30 June 2023 $'000
Current		
Trade payables	**18,253**	6,411
Deferred consideration[1]	**19,706**	40,000
Accruals (capital and operating expenditures)	**40,135**	22,268
	78,094	68,679
Non-Current		
Deferred consideration[1]	-	19,262

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

10. Provisions

	31 December 2023 $'000	30 June 2023 $'000
Current Liabilities		
Employee provisions	**3,558**	4,547
Restoration provisions	**173,973**	161,551
	177,531	166,098
Non-Current Liabilities		
Employee provisions	**1,115**	763
Restoration provisions	**425,972**	416,746
	427,087	417,509

	31 December 2023 $'000
Movement in carrying amount of the current restoration provision:	
Carrying amount at beginning of period	**161,551**
Restoration expenditure incurred	**(64,800)**
Changes in provisions[1]	**77,011**
Transferred from non-current provisions	**211**
Carrying amount at end of period	**173,973**
Movement in carrying amount of the non-current restoration provision:	
Carrying amount at beginning of period	**416,553**
Changes in provisions[1]	**965**
Transferred from/(to) current provisions	**(211)**
Increase through accretion	**8,665**
Carrying amount at end of period	**425,972**

[1] Changes in provisions for the period relate primarily to the increase in the estimated cost of the BMG wells decommissioning activities, consistent with the programme's mid-case cost estimate revision announced on 22 January 2024, and following earlier disclosures on this activity. This change is an adjusting event after the reporting period. The provision is also updated for changes to assumed discount rates, to discount future expected costs in order to derive the present value included here within the restoration provision. Other changes to estimates of the cost 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 or the regulator's assessment as to the scope of remediation necessary.

The discount rate used in the calculation of the provisions as at 31 December 2023 ranged from 3.61% to 5.04% (30 June 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 to relevant government bond rates since the last assessment.

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. In December 2022, Cooper Energy filed a claim in the Supreme Court of Victoria against Pertamina, 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.

11. Interest bearing loans and borrowings

	31 December 2023 $'000	30 June 2023 $'000
Non-current bank debt[1]	**204,927**	143,956

[1]Net of capitalised transaction costs of $13.1 million (30 June 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 Company's share of the BMG decommissioning project and a portion of the planned OP3D growth project in the

11. Interest bearing loans and borrowings continued

Otway Basin. Cooper Energy is in compliance with all covenants at 31 December 2023. 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] (30 June 2023: $400.0 million)	$20.0 million (30 June 2023: $20.0 million)
Utilised amount	$218.0 million (30 June 2023: $158.0 million)	$7.8 million[4] (30 June 2023: $7.7 million)
Accounting balance	$204.9 million (30 June 2023: $144.0 million)	Nil (30 June 2023: Nil)
Effective interest rate[2]	9.47% floating	Nil
Maturity[3]	30 September 2027[3]	30 September 2024

[1] As at 31 December 2023, $182.0 million of the original facility limit of $400.0 million remains available.
[2] Includes unwind of capitalised transaction costs
[3] Based on the facility repayment schedule, the reserves profile of the borrowing base assets and the facility maturity date.
[4] As at 31 December 2023, no cash amounts have been drawn, $7.8 million has been utilised by way of bank guarantees.

12. Net finance costs

	31 December 2023 $'000	31 December 2022 $'000
Finance Income		
Interest income	**2,031**	1,307
Finance Costs		
Unwind discount on liabilities	**(9,167)**	(9,116)
Finance cost associated with lease liabilities	**(286)**	(255)
Interest expense	**(8,073)**	(6,028)
Total finance costs	**(17,526)**	(15,399)
Net finance costs	**(15,495)**	(14,092)

13. Contributed equity

	31 December 2023 $'000	30 June 2023 $'000
Ordinary shares		
Issued and fully paid	**718,881**	716,726

	31 December 2023	
	Thousands	**$'000**
Movement in ordinary shares on issue		
At 1 July 2023	**2,631,530**	**716,726**
Issuance of shares for performance rights and share appreciation rights	**8,507**	**2,155**
At 31 December 2023	**2,640,037**	**718,881**

14. Financial Instruments

Fair value hierarchy
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 at the end of each reporting period and based on the lowest level input that is significant to the fair value measurement as a whole.

Set out below are the carrying amounts and fair values of financial instruments held by the Group:

		Carrying amount		**Fair value**	
Consolidated	**Level**	**31 December 2023 $'000**	30 June 2023 $'000	**31 December 2023 $'000**	30 June 2023 $'000
Financial assets					
Trade and other receivables	**2**	**23,552**	28,797	**23,552**	28,797
Equity instruments	**1**	**954**	1,131	**954**	1,131
Financial liabilities					
Trade and other payables	**2**	**78,094**	87,941	**78,094**	87,941
Success fee financial liability	**3**	**2,875**	2,853	**2,875**	2,853
Interest bearing loans and borrowings	**2**	**204,927**	143,956	**215,141**	158,257

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 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 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 31 December 2023 equalled 3.96% (30 June 2023: 4.03%). The financial liability is measured at fair value through profit and loss and valued using a discounted cash flow model and the value is sensitive to changes in discount rate and probability of payment. Significant changes in any of the significant unobservable inputs would result in significantly higher or lower fair value measurement.

15. Subsequent events

There are no significant events subsequent to 31 December 2023 at the date of this report.

Directors’ Declaration

In accordance with a resolution of the directors of Cooper Energy Limited, we 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 financial position at 31 December 2023 and the performance for the half-year ended on that date of the consolidated entity; and

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

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

On behalf of the Board

Mr John C Conde AO
Chairman

Ms Jane L Norman
Managing Director & CEO

27 February 2024

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Independent Auditor's Review Report to the Members of Cooper Energy Limited

Conclusion

We have reviewed the accompanying half-year financial report of Cooper Energy Limited (the Company) and its subsidiaries (collectively the Group), which comprises the consolidated statement of financial position as at 31 December 2023, the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the half-year ended on that date, notes comprising a summary of significant accounting policies and other explanatory information, and the directors' declaration.

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

a) giving a true and fair view of the consolidated financial position of the Group as at 31 December 2023 and of its consolidated financial performance for the half-year ended on that date; and

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

Basis for Conclusion

We conducted our review in accordance with ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity* (ASRE 2410). Our responsibilities are further described in the *Auditor's responsibilities for the review of the half-year financial report* section of our report. We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional 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 annual financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

Directors' Responsibilities for the Half-Year Financial Report

The directors of the Company are responsible for the preparation of the half-year financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the half-year financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

Building a better working world

Auditor's Responsibilities for the Review of the Half-Year Financial Report

Our responsibility is to express a conclusion on the half-year financial report based on our review. ASRE 2410 requires us to conclude whether we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including giving a true and fair view of the Group's financial position as at 31 December 2023 and its performance for the half-year ended on that date, and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

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

Ernst & Young

Darryn Hall

Partner
Adelaide
27 February 2024

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 term “financial year” or “FY24” refers to the 12 months ending 30 June 2024 unless otherwise stated. The term “calendar year end” refers to 31 December 2023 unless otherwise stated.

$: Australian dollars unless specified otherwise

AEMO: Australian Energy Market Operator

AGP: Athena gas plant

bbls: barrels of oil

Bcf: billion cubic feet

BMG: Basker Manta Gummy

boe: barrels of oil equivalent

EBITDAX: earnings before interest, tax, depreciation, amortisation, restoration, exploration and evaluation expense and impairment

FTE: full time equivalent

GSA: gas sales agreement

kbbl: thousand barrels of oil

LNG: liquified natural gas

LTI: lost time injury

MMbbl: million barrels of oil

MMboe: million barrels of oil equivalent

NPAT: net profit after tax

OGPP: Orbost gas processing plant

OP3D: Otway phase 3 development

PJ: petajoules

PJe: petajoules equivalent

TJ: terajoules

TJe/d: terajoules equivalent per day

2P: best estimate of reserves. The sum of proved plus probable reserves

2C: best estimate of contingent resources

Corporate Directory

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Jane L Norman, Managing Director
Timothy G Bednall
Giselle M Collins
Elizabeth A Donaghey
Jeffrey W Schneider

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Nicole Ortigosa

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