Quarterly Report

For the three months ended 31 December 2023

23 January 2024

Key features

- **Q2 FY24 production and revenue:** production up 3% from previous quarter to 61.7 TJe/d, revenue up 8% to $55.0 million from previous quarter
- **Orbost production:** Record daily production of 67.3 TJ/d and record instantaneous rate of 70.0 TJ/d, average quarterly production up 9% to 50.3 TJ/d on a like-for-like basis
- **BMG decommissioning:** Helix Q7000 on site and progressing through programme, mid case cost estimate A$240-280 million (100% gross)
- **Contracted gas:** GSA extension agreed with EnergyAustralia to supply 5 PJ/year for three years commencing January 2026
- **Cooper Energy remains well funded** from existing cash balances, positive operating cashflow generation and $400 million committed senior secured debt facility

Comments from Managing Director and CEO, Jane Norman

"I am pleased to report that during this quarter, total production increased 3% on the previous quarter and 12% on the same period in FY23. This was driven by strong production from Orbost, which itself was 9% higher than the previous quarter excluding the shutdown period in December. We are now realising positive outcomes from our Orbost Improvement Project, with further initiatives still underway. This has had a substantial impact on our revenue which increased 8% on the previous quarter.

"The Helix Q7000 vessel has commenced the BMG decommissioning work at the first well, Basker-3. While we are making progress with the scope of work, disappointingly that progress has been significantly slower than planned. The late arrival of the Helix Q7000 at the BMG field, together with start-up activities in the field taking longer than planned, consumed the budgeted contingency. The slow progress now experienced on Basker-3 decommissioning work to date, required us to reforecast the programme for the remaining six BMG wells.

"As a result of this re-forecasting, yesterday we revised the mid-case cost estimate to approximately A$240-280 million, inclusive of low FX rates and including reasonable contingency for future non-productive time and waiting on weather. We will continue to work with our contractors, in particular Helix, to pursue savings to offset increased costs, including implementing operational learnings and efficiencies and simplifying the scope of decommissioning.

"On a positive note, this quarter we secured a new gas sales agreement with a long-term foundational customer, EnergyAustralia. We also achieved a successful price review outcome on our Visy Glass agreement. These agreements signify the continued importance of gas in our economy, to homes and businesses. Our domestic gas supplies play a pivotal role in providing industrial heat and feedstock to manufacturers and flexible energy to support further integration of intermittent wind and solar into our electricity network.

"As highlighted in the Q1 FY24 quarterly report, a key business priority for us in FY24 is the cost-out initiatives, including reducing G&A by at least 10%. Further progress has been made during the quarter and a fulsome update will be given as part of the FY24 half year results."

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Key performance metrics

$ million unless indicated	Dec Q2 FY23	Sep Q1 FY24	**Dec Q2 FY24**	*Qtr on Qtr change*	FY23 YTD	**FY24 YTD**	*Change*
Production (PJe)	5.08	5.51	**5.68**	3%	11.14	**11.19**	*0%*
Sales volume (Pje)	5.18	5.78	**5.87**	*2%*	11.14	**11.65**	*5%*
Average gas price ($/GJ)	8.38	8.30	**8.58**	*3%*	8.75	**8.44**	*(3%)*
Sales revenue	45.8	50.8	**55.0**	*8%*	101.2	**105.8**	*5%*
Cash and cash equivalents	88.3	47.5	**101.2**	*113%*	88.3	**101.2**	*15%*
Net debt	69.7	110.5	**116.8**	*6%*	69.7	**116.8**	*68%*

Production

Quarterly gas and oil production averaged 61.7 TJe/d, or 5.68 PJe (0.93 MMboe) for the quarter, 3% higher than the prior quarter. This was mainly due to increased Sole gas production through improved performance at the Orbost Gas Processing Plant (OGPP).

Production by product	Dec Q2 FY23	Sep Q1 FY24	**Dec Q2 FY24**	*Qtr on Qtr change*	FY23 YTD	**FY24 YTD**	*Change*
Sales gas (PJ)	4.9	5.3	**5.5**	*4%*	10.8	**10.8**	*(0%)*
Oil and condensate (kbbl)	28.3	38.3	**31.3**	*(18%)*	56.9	**69.6**	*22%*
Total production (PJe)	5.08	5.51	**5.68**	*3%*	11.14	**11.19**	*0%*
Total production (MMboe)	0.83	0.90	**0.93**	*3%*	1.82	**1.83**	*0%*

Gippsland Basin (Sole)[1]

Sole gas production processed through OGPP averaged 48.6 TJ/d, or 4.5 PJ for the quarter, 5% higher than the prior quarter of 46.2 TJ/d despite the scheduled December shutdown. Excluding the shutdown, the average quarterly production was 50.3 TJ/d, 9% higher than the prior quarter. The planned maintenance shutdown was undertaken from 3 December to 6 December 2023 with the plant brought back online on 7 December. The increased production during the quarter was due mainly to the improved processing performance of OGPP.

During Q2 FY24 work continued on the Orbost Improvement Project. Focus included trialling new absorber bed packing material and re-instating the polisher unit, including a new type of polisher media loaded on 21 December. The new media is non-absorbent to 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.

The Orbost Improvement Project continues to progress multiple initiatives to improve the reliability of the plant and maximise production rates.

Otway Basin (Casino, Henry and Netherby)[2]

Casino, Henry and Netherby (CHN) gas production processed through the Athena Gas Plant (AGP) averaged 11.0 TJ/d or 1.0 PJ for the quarter (both net to Cooper Energy's 50% share), 2% lower than the prior quarter of 11.2 TJ/d. Well cycling operations continue to be implemented to optimise production from the CHN fields.

At the beginning of the quarter, a low inlet pressure trial was successfully conducted at AGP. Following comprehensive analyses and risk assessment, adjustments have been made at AGP to allow low inlet pressure operation since the end of December. This operational adjustment is expected to increase the instantaneous gas rate and extend CHN field life.

[1] Cooper Energy 100% and operator
[2] Cooper Energy 50% and operator

Cooper Basin[3]

Oil production in the Cooper Basin averaged 330 bbls/d, or 30.4 kbbls for the quarter (both net to Cooper Energy's 25% share), 19% lower than the prior quarter of 406 bbls/d. During the prior quarter average production rates were positively impacted by the connection of Rincon-4 in June 2023, and Callawonga-23 in July 2023, with flush production from those two wells contributing to a 20% increase in production from Q4 FY23 to Q1 FY24.

Production by basin	Dec Q2 FY23	Sep Q1 FY24	**Dec Q2 FY24**	*Qtr on Qtr change*	FY23 YTD	**FY24 YTD**	*Change*
Gippsland Basin (Sole)							
Sales gas (PJ)	4.0	4.2	**4.5**	*5%*	8.7	**8.7**	*(0%)*
Otway Basin (CHN)							
Sales gas (PJ)	0.9	1.0	**1.0**	*(2%)*	2.0	**2.0**	*(0%)*
Condensate (kbbl)	0.84	0.97	**1.0**	*(1%)*	1.9	**1.9**	*1%*
Cooper Basin							
Oil (kbbl)[4]	27.4	37.3	**30.4**	*(19%)*	54.9	**67.7**	*23%*
Total production (PJe)	5.08	5.51	**5.68**	*3%*	11.14	**11.19**	*0%*
Total production (MMboe)	0.83	0.90	**0.93**	*3%*	1.82	**1.83**	*0%*

Exploration and development

Gippsland Basin

BMG 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 and following loading of equipment and fuel in Geelong and Corner Inlet, arrived at the BMG site shortly after Christmas.

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, consumed the budgeted contingency.

On 22 January 2024, the Company revised its mid-case cost estimate for the BMG 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. 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.

The Company's focus remains on executing the decommissioning programme safely and within the minimum time possible. However, there remain certain risks, including variables outside of Cooper Energy's control, that could increase the total cost of the decommissioning above the updated estimate.

Otway Basin (Offshore)

Cooper Energy has continued to progress the Otway Phase 3 Development (OP3D) project and as previously reported has secured the Transocean Equinox rig, as part of a consortium agreement with three other operators. The contract is expected to commence during FY25, with Cooper Energy committed to one firm well, with options to drill additional subsea development and/or exploration/appraisal wells.

[3] Cooper Energy 25%, Beach Energy 75% and operator
[4] Cooper Basin production data is preliminary for the current quarter, awaiting December reconciled data.

Otway growth is expected to be funded from organic cash generation, supported by existing committed senior secured bank debt as well as the $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.

New developments can be connected to Cooper Energy's existing gas processing infrastructure at the AGP, which has ~150 TJ/d of total capacity and current utilisation of ~25 TJ/d (both 100% gross).

Otway Basin (Onshore)

In the onshore Otway Basin in South Australia, processing of the PEL 494 Dombey 3D seismic survey was completed during the quarter. Interpretation of the 3D seismic data will delineate the resource potential of the Dombey gas field and identify potential new exploration opportunities.

Several legacy 3D seismic datasets across PEP 168 have been reprocessed into one survey and received in late December. Interpretation of this reprocessed seismic will be undertaken during Q3 FY24, to further mature drilling prospects in the permit.

Cooper Basin

Three exploration wells were drilled in ex-PEL 92 during the quarter. The Bangalee South-1 exploration well intersected 2.9 metres of net oil pay in the Namur reservoir and 4.3 metres net oil pay in the Birkhead reservoir. The Birkhead zone was brought online in December, with recent production above 350 bopd.

As well as Bangalee South-1, the Company participated in two additional wells during the drilling campaign. Wooley Rock-1 intersected 1.2 metres of net pay and was plugged and abandoned as a non-commercial discovery. Chadinga-1 was drilled approximately three kilometres northwest of the Wooley Rock discovery and was plugged and abandoned having failed to encounter hydrocarbons.

Financial

Sales volume and revenue

Total Q2 FY24 gas and oil volumes sold averaged 63.8 TJe/d, or 5.87 PJe for the quarter, 2% higher than the previous quarter of 62.8 TJe/d or 5.78 PJe.

Surplus Gippsland gas production, relative to the Sole term contracts, resulted in spot gas sales of 903 TJ (Q1 FY24: 254 TJ). Higher and more stable production during the quarter meant gas purchases were down to 47 TJ (Q1 FY24: 284 TJ).

Total gas and oil sales revenue was 8% higher at $55.0 million, due to higher average realised gas prices across both basins of $8.58/GJ (Q1 FY24 $8.30/GJ) and a 53% increase in oil sales volumes.

The higher average realised gas price in Q2 FY24 was due to higher spot volume sales as well as higher average spot prices of $10.22/GJ (Q1 FY24 $8.85/GJ). During the quarter 84% of gas production was sold into term contracts (Q1 FY24: 95%) at an average price of $8.26/GJ (Q1 FY24: $8.28/GJ).

PEL 92 volumes sold were 54,635 bbls (Q1 FY24: 35,722 bbls) at an average oil price realisation of A$136.19/bbl (Q1 FY24: A$128.40/bbl). An additional cargo of crude was lifted in Q2 compared to Q1.

Total liquids revenue, including condensate, was $7.5 million in the quarter (Q1 FY24 $4.7 million). Crude oil inventory at 31 December 2023 was 3,213 bbls (30 September 2023: 27,858 bbls).

		Dec Q2 FY23	Sep Q1 FY24	**Dec Q2 FY24**	*Qtr on Qtr change*	FY23 YTD	**FY24 YTD**	*Change*
Sales volume								
Gas	PJ	5.1	5.6	**5.5**	*0%*	10.9	**11.1**	*2%*
Oil	kbbl	20.7	35.7	**54.6**	*53%*	36.2	**90.4**	*150%*
Condensate	kbbl	0.8	1.0	**0.9**	*(8%)*	1.8	**1.9**	*3%*

Total sales volume	PJe	5.18	5.78	**5.87**	*2%*	11.14	**11.65**	*5%*
Sales revenue ($ million)								
Gas[5]		42.3	46.1	**47.5**	*3%*	95.4	**93.6**	*(2%)*
Oil and condensate		3.5	4.7	**7.5**	*60%*	5.8	**12.3**	*111%*
Total sales revenue		45.8	50.8	**55.0**	*8%*	101.2	**105.8**	*5%*
Average realised prices								
Gas	$/GJ	8.38	8.30	**8.58**	*3%*	8.75	**8.44**	*(3%)*
Oil and condensate	$/boe	144.39	128.40	**136.19**	*6%*	145.36	**133.09**	*(8%)*

The tables below summarise gas sales and sources.

Sole GSA sales and sources		Sept Q1 FY24	**Dec Q2 FY24**		Sept Q1 FY24	**Dec Q2 FY24**
Sole GSA sales	PJ	4.2	**3.6**	TJ/d (average)	46	**39**
Sole spot sales	PJ	0.3	**0.9**[6]	TJ/d (average)	3	**10**
Comprising:						
OGPP processing	PJ	4.2	**4.5**	TJ/d (average)	46	**49**
Third-party gas purchases	PJ	0.3	**0.0**[7]	TJ/d (average)	3	**1**

CHN GSA sales and sources		Sept Q1 FY24	**Dec Q2 FY24**		Sept Q1 FY24	**Dec Q2 FY24**
CHN GSA sales	PJ	1.0	**1.0**	TJ/d (average)	11	**11**

Capital expenditure

Q2 FY24 incurred capital expenditure of $5.0 million was higher than the prior quarter as it included spend relating to drilling in the Cooper Basin, as well as the Orbost Improvement Project.

$ million	Dec Q2 FY23	Sep Q1 FY24	**Dec Q2 FY24**	*Qtr on Qtr change*	FY23 YTD	**FY24 YTD**	*Change*
Exploration and appraisal	7.1	1.1	**2.4**	*107%*	15.0	**3.5**	*(76%)*
Development	6.9	0.7	**2.6**	*273%*	7.9	**3.3**	*(59%)*
Total capital expenditure	14.0	1.8	**5.0**	*169%*	22.9	**6.8**	*(70%)*

By basin, $ million	**Q2 FY24**			**FY24**		
	Exploration	Development	**Total**	Exploration	Development	**Total**
Otway Basin	0.4	-	**0.4**	0.8	-	**0.8**
Gippsland Basin	0.1	1.9	**2.0**	0.8	2.1	**2.9**
Cooper Basin	1.9	0.7	**2.6**	1.9	1.0	**2.9**
Other	-	-	**-**	-	0.2	**0.2**
Total capital expenditure	2.4	2.6	**5.0**	3.5	3.3	**6.8**

[5] Includes sale of third-party gas purchases
[6] Sole spot sales were 903 TJ in Q2 FY24 (Q1 FY24: 254 TJ)
[7] Third-party gas purchases were 47 TJ in Q2 FY24 (Q1 FY24: 284 TJ)

Liquidity

As at 31 December 2023, Cooper Energy had cash reserves of $101.2 million (Q1 FY24: $47.5 million), with drawn debt at $218.0 million (Q1 FY24: $158.0 million), as summarised below.

$ million	Dec Q2 FY23	Sep Q1 FY24	**Dec Q2 FY24**	*Qtr on Qtr change*	FY23 YTD	**FY24 YTD**	*Change*
Cash and cash equivalents	88.3	47.5	**101.2**	*113%*	88.3	**101.2**	*15%*
Drawn debt	158.0	158.0	**218.0**	*38%*	158.0	**218.0**	*38%*
Net debt	69.7	110.5	**116.8**	*6%*	69.7	**116.8**	*68%*

Whilst revenue generated for the quarter was $55.0 million, up 8% from Q1 FY24, the spend on decommissioning of $23.9 million associated with the pre-abandonment programme and ramp up of work on BMG impacted quarterly cash generation versus Q1 FY24, among other factors.

Given the delays to the timing of the BMG wells decommissioning, the Group's net debt and ratio of net debt/EBITDA (the latter, on a next twelve-month basis), are now expected to peak in late Q4 FY24 or early Q1 FY25, relative to the outlook provided on 29 August 2023. Based on the top end of the revised mid case estimate for the BMG wells decommissioning, net debt is anticipated to peak at up to approximately $50 million more than was indicated in the August 2023 outlook, while the peak of the ratio of net debt/EBITDA is not expected to change materially given the shift in phasing of the decommissioning spend and the various improvements in the underlying performance of the business.

Commercial, corporate and subsequent events

EnergyAustralia Gas Sales Agreement

During the quarter the Company signed an agreement with EnergyAustralia to extend the domestic supply term under their existing Sole gas sales agreement (GSA).

Under the 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[8].

Visy Glass Gas Sales Agreement

During the quarter 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.

Physical Gas Portfolio Management

During the quarter the Company implemented a revised suite of transport and storage services on the Eastern Gas Pipeline. The new arrangements provide for increased flexibility to manage daily physical imbalances between OGPP production and customer GSA demand, and the opportunity to increase high values of surplus gas sales.

Cost-out initiative

As previously outlined, a key priority in FY24 is the cost-out initiative, an all-encompassing review including production costs and targeting at least 10% savings in G&A.

There are now close to 90 actions identified in the cost-out initiative with 13 now completed and with the bulk to be completed in FY24, delivering into FY25. A more detailed update will be provided as part of the half yearly reporting in February.

[8] ACCC Gas inquiry December 2023, interim update on east coast gas market, page 87

Pertamina

The Company continues to pursue its claim in the Supreme Court of Victoria (Court) against PT Pertamina Hulu Energi ("Pertamina") for Pertamina's 10% share of the BMG decommissioning costs. Pertamina, via an Australian subsidiary, participated in the BMG oil project during its production life and Cooper Energy's claim against Pertamina arises with respect to obligations under the withdrawal and abandonment provisions of the BMG oil project joint operating and production agreement.

The Company filed an application for default judgment on 14 December 2023, and expects to be allocated a hearing date in early to mid-2024.

PEP 169 farm-in

In October 2023 Cooper Energy and Lakes Blue Energy agreed to binding terms for the Company to farm in to PEP 169 for a 25.1% participating interest. PEP 169 is located in the onshore Otway Basin, Victoria. During the quarter, work continued to finalise the arrangements.

The agreement comprises an upfront consideration 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. The transaction is conditional on the completion of due diligence, negotiation of transaction documents and obtaining necessary consents and regulatory approvals.

The Enterprise North prospect is located less than three kilometres from the Cooper Energy operated AGP.

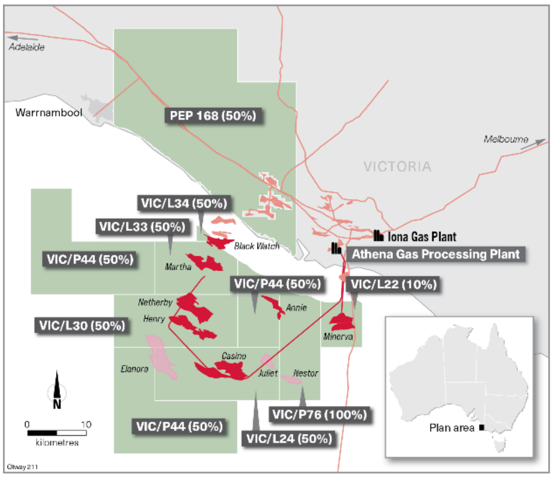
Annual redetermination of senior secured bank loan

In December 2023 the Company achieved a positive outcome from the annual redetermination of its A$400 million senior secured bank loan, in part due to the increase in contracted gas prices. As a result, the assessed borrowing base under the bank group's assumptions has increased, providing greater funding flexibility over the life of the loan. The result of the redetermination reiterates the strong support the Company continues to receive from the lending group.

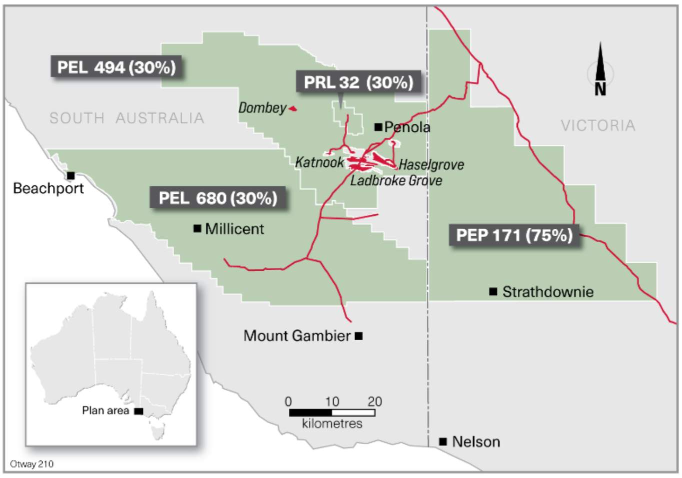
Cooper Energy tenements

Please refer to Cooper Energy's 2023 Annual Report for further information regarding tenement interests.

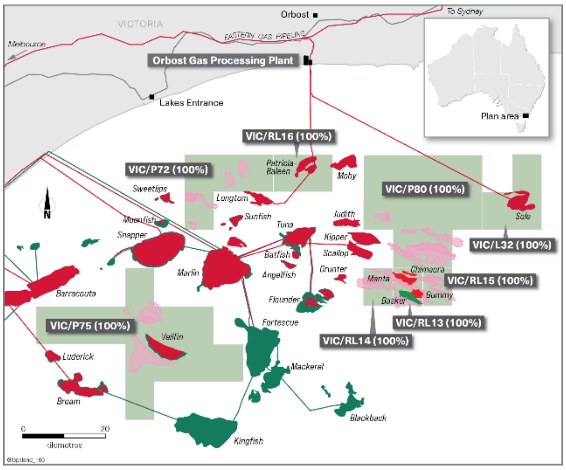
Otway Basin (Victoria):



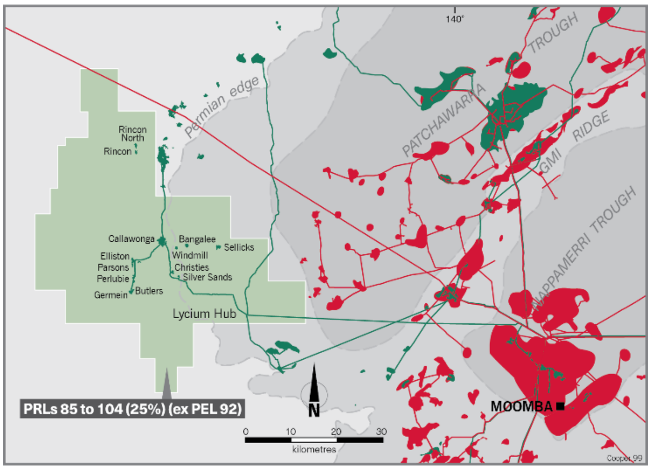
Otway Basin (onshore):

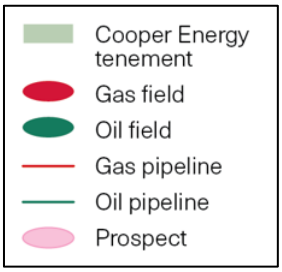


Gippsland Basin:



Cooper Basin:





Terms, abbreviations and conversion factors

Terms and abbreviations

$	Australian dollars
bbls	Barrels
BMG	Basker, Manta and Gummy fields
CHN	Casino, Henry and Netherby fields
Cooper Energy or **the Company**	Cooper Energy Limited ABN 93 096 170 295
GSA	Gas Sales Agreement
kbbl	Thousand barrels
MMboe	Million barrels of oil equivalent
OP3D	Otway Phase 3 Development
PEL	Petroleum Exploration Licence
PEP	Petroleum Exploration Permit
PJ	Petajoules
TJ	Terajoules of gas
TJ/d	Terajoules of gas per day

Conversion factors

Gas	1 PJ	= 0.163 MMboe
Oil	1 bbl 1 MMboe	= 1 boe = 6.11932 PJe
Condensate	1 bbl	= 1 boe

Disclaimer

This report contains forward looking statements, including statements of current intention, statements of opinion and expectations regarding Cooper Energy's present and future operations, possible future events and future financial prospects. Such statements are not statements of fact and may be affected by a range of variables which could cause Cooper Energy's actual results, performance or trends to materially differ from the results or performance expressed or implied by such statements. There can be no certainty of outcome in relation to the matters to which the statements relate, and the outcomes are not all within the control of Cooper Energy.

Cooper Energy makes no representation, assurance or guarantee as to the accuracy or likelihood of fulfilment of any forward-looking statement or any outcomes expressed or implied in any forward-looking statement. The forward-looking statements in this report reflect expectations held at the date of this report. Except as required by applicable law or the ASX Listing Rules, Cooper Energy disclaims any obligation or undertaking to publicly update any forward-looking statements, or discussion of future financial prospects, whether as a result of new information or of future events.

Numbers in this report have been rounded. As a result, some figures may differ insignificantly due to rounding and totals reported may differ insignificantly from arithmetic addition of the rounded numbers.