Q2 FY20

Quarterly Report for 3 months to 31 December 2019

28 January 2020

Key features:

- **Quarterly production:** 0.27 million boe, down from prior quarter's 0.39 million boe
- **Quarterly revenue:** $16.4 million, down from $22.7 million in prior quarter
- **Half year production:** unchanged, at 0.66 million boe for six months to 31 December
- **Half year revenue:** up 8%, to a first half record of $39.1 million from $36.2 million
- **Sole Gas Project:** Orbost plant commissioning impacted by bushfire, gas to plant anticipated in February
- **Exploration:** Cooper Basin - 7 appraisal wells test field limits at Callawonga and Butlers; onshore Otway Basin - Dombey confirms new fairway in the Penola Trough

Managing Director's comments

"December quarter results have seen us post record revenue for the 6 months to 31 December. Sales revenue in our growing gas business increased 12% when compared to the previous first half. The acquisition of the Minerva Gas Plant in December was a major milestone. We are delighted with the flexibility the plant adds to our Otway gas operations and to add an asset of this calibre to our portfolio. We are now working towards a final investment decision for the plant modifications and the connections we have planned.

"The most significant event of the quarter was the East Gippsland bushfires. We are thankful all associated with the Orbost Gas Processing Plant were kept safe and the plant was not damaged. We reiterate our appreciation for the sacrifice and efforts of the emergency workers and their families. We are mindful of the loss suffered in the community and will follow up the donations made in January with further commitment to support the recovery and rebuilding of East Gippsland. The Orbost plant commissioning, which was interrupted due to the bushfires, is now proceeding towards receiving first gas from Sole in February."

Key Measures

$ million unless indicated	**3 months to 31 Dec 19**	Prior Qtr Sept 19	Qtr on Qtr change %	**FY20 YTD**	**FY19 YTD**	Yr on Yr change %
Production million boe	**0.27**	0.39	*-31%*	**0.66**	0.66	-
Sales revenue	**16.4**	22.7	*-28%*	**39.1**	36.2	*8%*
Capital expenditure (cash)	**28.5**	21.0	*36%*	**49.5**	120.1	*-59%*
Cash at end of quarter	**150.7**	166.8	*- 10%*	**150.7**	193.9	*-22%*
Net debt/(cash) at end of quarter	**73.3**	54.3	*35%*	**73.3**	(7.5)	*1,077%*

Further comment and information:

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This quarterly report approved and authorised by
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Financial

Sales

Sales revenue for the 3 months to 31 December 2019 (the December quarter) was $16.4 million; 28% lower than the prior quarter's $22.7 million due to lower gas and oil volumes and lower oil prices. Revenue from the sale of gas was $11.2 million, 35% lower than the prior quarter's $17.2 million. The average realised AUD oil price for the quarter was A$101.00/bbl, 6% lower the prior quarter's A$107.48/bbl.

Sales revenue for the year to date (first half) of $39.1 million was 8% higher than the prior corresponding period (pcp) revenue of $36.2 million and the highest first half revenue yet recorded by Cooper Energy. The increase in half year revenue is attributable to higher gas production and prices which offset lower oil prices and volume.

Capital expenditure

During the quarter the company incurred capital expenditure of $24.3 million compared with $39.3 million in the prior quarter. The movement can be attributed to higher exploration expenditure in the Otway Basin and higher development expenditure in the Gippsland Basin in the prior quarter.

Noteworthy elements of the capital expenditure incurred in the December quarter included:

1) Otway Basin exploration of $3.7 million ($23.2 million in the prior quarter) being expenditure incurred on the Annie and Dombey wells.
2) Gippsland development of $6.9 million, ($10.6 million in the prior quarter) the major share of which is capitalised interest and finance costs.
3) Cooper Basin exploration and development expenditure of $3.2 million ($2.9 million in the prior quarter).
4) Other development expenditure of $9.2 million, most of which is attributable to the acquisition of the Minerva Gas Plant.

Incurred capital expenditure

	December quarter 2019			Year to date FY20		
$ million	Exploration	Development	Total	Exploration	Development	Total
Otway Basin	3.7	1.1	**4.8**	26.9	1.5	**28.4**
Gippsland Basin	0.2	6.9	**7.1**	1.2	17.5	**18.7**
Cooper Basin	2.6	0.6	**3.2**	4.5	1.6	**6.1**
Other	-	9.2	**9.2**	-	10.4	**10.4**
Total	6.5	17.8	**24.3**	32.6	31.0	**63.6**

Cash capital expenditure totaled $28.5 million with the difference against incurred capital expenditure for the period being largely explained by payments for Otway Basin exploration incurred in the prior quarter.

Cash capital expenditure

	December quarter 2019			Year to date FY20		
$ million	Exploration	Development	Total	Exploration	Development	Total
Otway Basin	15.2	1.4	**16.6**	25.4	3.0	**28.4**
Gippsland Basin	0.8	5.5	**6.3**	1.1	10.9	**12.0**
Cooper Basin	1.3	1.1	**2.4**	3.3	1.4	**4.7**
Other	-	3.2	**3.2**	-	4.4	**4.4**
Total	17.3	11.2	**28.5**	29.8	19.7	**49.5**

Cash and borrowings

Cash at 31 December was $150.7 million, compared with $166.8 million at the beginning of the quarter. Borrowings increased from $221.1 million to $224.0 million. Net debt increased from $54.3 million to $73.3 million during the quarter.

Commodity hedging

Cooper Energy uses hedging to protect against downside oil price scenarios and retain partial exposure to higher oil prices. Hedging in place as at 31 December 2019 is as follows:

(bbl remaining as at 31 December 2019):	
US$50.00 – U$69.00 zero cost collar options	9,127

Quarterly financial statistics

Refer notes below for information on calculation		**Dec 19 qtr**	Prior qtr Sept 19	PCP qtr Dec 18	Change on prior qtr %	Change on PCP %	**FY20 YTD**	FY19 PCP	Yr on Yr change %
Sales									
Sales revenue	$ million	**16.4**	22.7	14.4	*-28%*	*14%*	**39.1**	36.2	*8%*
Sales volume	Gas PJ	**1.3**	2.1	1.4	*-38%*	*-7%*	**3.4**	3.3	*3%*
	Oil kbbl	**47.6**	50.3	57.2	*-5%*	*-17%*	**97.9**	117.1	*-16%*
	Condensate kbbl	**0.7**	1.6	1.2	*-56%*	*-42%*	**2.3**	2.5	*-8%*
Oil direct operating cost	AUD/bbl	**34.80**	35.20	34.16	*-1%*	*2%*	**35.00**	35.19	*-1%*
Capital Expenditure (incurred $ million)									
Exploration & appraisal		**6.5**	26.1	2.0	*-75%*	*225%*	**32.6**	2.7	*1,111%*
Development & fixed assets		**17.8**	13.2	39.0	*35%*	*-54%*	**31.0**	105.2	*-71%*
Total incurred capital expenditure		**24.3**	39.3	41.0	*-38%*	*-41%*	**63.6**	107.9	*-41%*
Capital Expenditure (cash $ million)		**28.5**	21.0	44.0	*36%*	*-35%*	**49.5**	120.1	*-59%*
Cash and borrowings ($ million)									
Cash and term deposits		**150.7**	166.8	193.9	*-10%*	*-22%*	**150.7**	193.9	*-22%*
Cash held in escrow		**-**	-	1.7	*0%*	*-100%*	**-**	1.7	*-100%*
Investments		**1.2**	1.4	1.6	*-14%*	*-25%*	**1.2**	1.6	*-25%*
Total financial assets		**151.9**	168.2	197.2	*-10%*	*-23%*	**151.9**	197.2	*-23%*
Total drawn debt		**224.0**	221.1	186.4	*1%*	*20%*	**224.0**	186.4	*20%*
Net debt /(cash)		**73.3**	54.3	(7.5)	*35%*	*1,077%*	**73.3**	(7.5)	*1,077%*
Issued Capital (million)									
Issued shares		**1,626.6**	1,621.6	1,621.6	*0%*	*0%*	**1,626.6**	1,621.6	*0%*
Performance Rights		**17.9**	16.0	16.0	*12%*	*12%*	**17.9**	16.0	*12%*
Share Appreciation Rights		**48.3**	39.8	39.8	*21%*	*21%*	**48.3**	39.8	*21%*

Notes:

- Sales figures for most recent quarter are preliminary
- Sales revenue includes impacts from provisional pricing.
- Prior periods have been updated for final reconciled figures
- Direct operating costs include production, transport and royalties
- Investments shown at fair value at the reporting date shown
- Drawn debt excludes capitalised transaction costs

Production

Total production for the December quarter of 0.27 MMboe was 31% lower than the prior quarter and 7% below the previous corresponding period due to lower production of gas and oil. Total production for the six months to 31 December was unchanged at 0.66 MMboe.

Discussion of factors in the quarterly production is provided under 'Operations review' commencing page 7.

Cooper Energy share of production for 3 months to 31 December 2019 and financial year to date

By product		Dec qtr 19	Prior qtr Sept 19	PCP qtr Dec 18	Change on prior qtr %	Change on PCP %	FY20 YTD	FY19 PCP	Yr on Yr change %
Sales gas	PJ	**1.34**	2.07	1.40	-35%	- 5%	**3.41**	3.28	4%
Crude oil & condensate	kbbl	**48.75**	53.70	59.98	- 9%	- 19%	**102.45**	122.47	- 16%
Total	**MMboe**	**0.27**	0.39	0.29	-31%	- 7%	**0.66**	0.66	-

By project		Dec qtr 19	Prior qtr Sept 19	PCP qtr Dec 18	Change on prior qtr %	Change on PCP %	FY20 YTD	FY19 PCP	Yr on Yr change %
Casino Henry									
Sales gas	PJ	**1.34**	1.75	1.11	-24%	21%	**3.09**	2.74	13%
Condensate	kbbl	**0.68**	0.87	0.34	-22%	100%	**1.55**	0.86	80%
Minerva									
Sales gas	PJ	**0.00**	0.32	0.29	-100%	-100%	**0.32**	0.55	-42%
Condensate	kbbl	**0.00**	0.76	0.87	-100%	-100%	**0.76**	1.61	-53%
Cooper Basin									
Crude oil	kbbl	**48.07**	52.07	58.77	-7%	-18%	**100.14**	120.00	-16%
Total	**MMboe**	**0.27**	0.39	0.29	-31%	-7%	**0.66**	0.66	-

Note: figures rounded. As a result, some totals and percentage changes displayed may not equate with calculation of figures displayed. Prior periods have been updated from those previously published for final reconciled figures where necessary.

Corporate

Cooper Energy Operating Model and Senior Management responsibilities

The company implemented a new operating model with changes to senior management accountabilities effective from 1 January 2020.

Cooper Energy has developed a valuable portfolio of opportunities. The new operating model has been introduced to enable optimum performance in asset management, governance and the allocation of resources consistent with the aspirations of the company.

Senior management oversight and decision making is executed through a 7-person Executive Leadership Team comprising:

- Managing Director, David Maxwell;
- Chief Financial Officer, Virginia Suttell;
- General Manager, Commercial and Development, Eddy Glavas (previously GM Commercial & Business development);
- General Manager, Exploration and Subsurface, Andrew Thomas;
- General Manager, Projects and Operations, Mike Jacobsen (previously GM Projects);
- General Manager, HSEC & Technical Services, Iain MacDougall (previously GM Operations); and
- Company Secretary and General Counsel: Amelia Jalleh.

Duncan Clegg, previously General Manager, Development and a member of the Executive Leadership Team, has assumed a part-time role focusing on special projects.

Operations review

Otway Basin

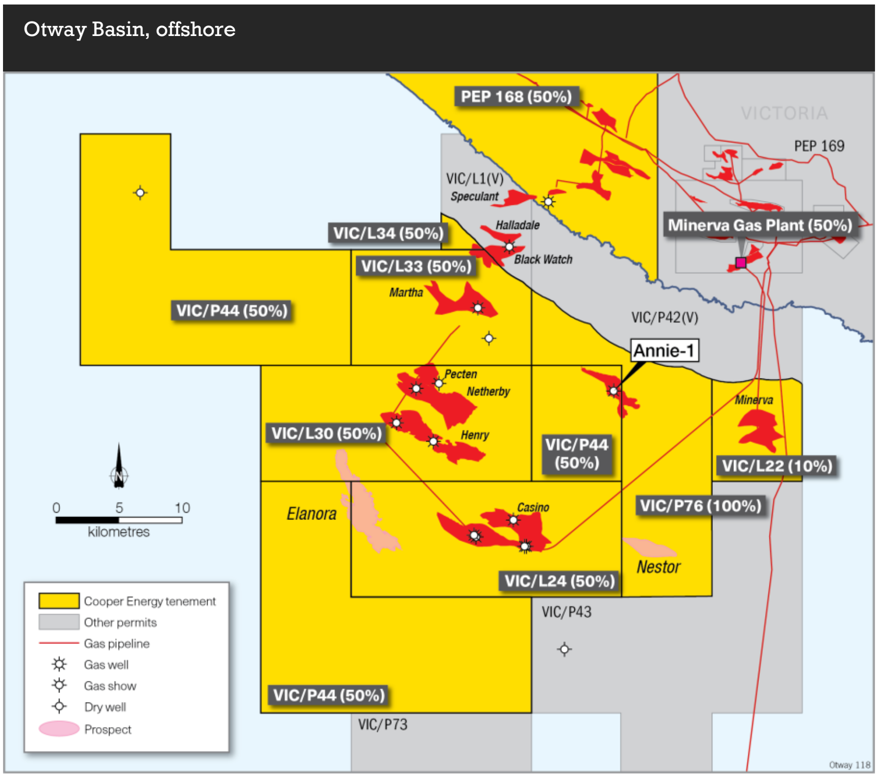
Offshore

The company's interests in the Otway Basin offshore Victoria include:

a) a 50% interest in, and Operatorship of, the producing Casino Henry Netherby ("Casino Henry") Joint Venture (VIC/L24 and VIC/L30). Mitsui E&P Australia and its associated entities ("Mitsui") hold the remaining 50% interest;

b) a 50% interest in, and Operatorship of production licences VIC/L33 and VIC/L34 which contain part of the undeveloped Black Watch gas field. Mitsui holds the remaining 50% interest.

c) a 50% interest in, and Operatorship of, the VIC/P44 exploration permit. Mitsui hold the remaining 50% interest.



d) a 100% interest in the exploration permit VIC/PL76.

e) a 50% interest in, and Operatorship of, the Minerva Gas Plant located onshore Victoria. Mitsui hold the remaining 50% interest; and

f) a 10% interest in the Minerva gas field (VIC/L22) which ceased production on 3 September. BHP Petroleum is the Operator and holder of a 90% interest.

Production

Cooper Energy's share of production from the offshore Otway Basin during the December quarter comprised 1.34 PJ of gas and 0.68 kbbl of condensate from Casino Henry. Gas production averaged 33 TJ/day compared with 41 TJ/day in the September quarter which had benefited from recharge from shut-in during the preceding quarter. In comparison, the lower production in the December quarter is due to well depletion, a two-week planned shut-down at the Iona Gas Plant and the cessation of Minerva gas field production on 3 September. Production from the December quarter 2018 was 24.1 TJ/day.

Exploration

VIC/P44: Annie gas field discovery

The Annie gas field was discovered in September 2019 when Annie-1 intersected a 70-metre gas column in the primary Waarre C target formation. Net gas pay thickness in the Waarre C was 62 metres. The field is located approximately 9 km offshore Victoria in a water depth of 58 metres, between the Henry (15 km west) and Minerva (11 km east) gas fields.

Geological data collected from Annie-1 has been undergoing analysis and assessment. These studies are ongoing and directed to the completion of a resource assessment to inform decisions on development options. It is expected, subject to the results of these studies and the Concept Select phase, that FID on development of the Annie gas field may be taken prior to the completion of the current calendar year.

Development prospects for the Annie discovery are enhanced by its location. The proximity of subsea infrastructure for the nearby producing gas fields offers simplified development options and economics. The availability of the Minerva Gas Plant is an attractive processing option for Annie and future developments in the region.

VIC/P76

VICP/76 borders the VIC/P44 and VIC/L24 licenses which contain the Annie discovery and producing Casino gas fields. The permit comprises an area of 162 km^2 in water depth of 60 to 70 metres. Good quality 3D seismic data covers most of the permit from which Cooper Energy has an amplitude-supported prospect called Nestor, which has many similarities to the Annie gas discovery. Nestor is located 9 km east of the Casino gas field and close to existing subsea infrastructure (refer map on preceding page). The prospectivity potential of the permit is being updated incorporating the results at Annie-1.

VICP/76 was granted for a six-year term. A guaranteed work program over the first three years consists of geological and geophysical studies and the drilling of one exploration well.

Development

Minerva Gas Processing Project

Acquisition of the Minerva Gas Plant by Cooper Energy and Mitsui was completed on 4 December.

The plant has been acquired to process gas from the Casino, Henry and Netherby gas fields and from economic new discoveries anticipated from exploration. Annie is the first new discovery proposed for processing at the plant and the subject of analysis and modelling to determine resource size and development options.

The connection of existing producing fields to the plant is expected to deliver benefits including lower processing costs, improved recovery enabled by lower inlet pressure and the capability to offer customers uninterruptable supply. The Minerva Gas Plant has processing capacity of up to 150 TJ/day and capability for processing of liquid hydrocarbons.

The Minerva Gas Processing Project will involve minor modification to the gas plant, connection of onshore pipelines and connection of the Casino Henry control system to the Minerva Gas Plant control room and associated regulatory approvals. First gas through the plant is expected in the June quarter 2021.

Cooper Energy, as Operator, has taken possession of the plant, which is currently in care and maintenance mode. A small team has been employed, consisting of some of the plant's previous workforce, with a view to progressing to full staffing levels as the project approaches completion. The project is currently advancing towards FID anticipated in the March quarter 2020.

Otway Phase-3 Development: Henry development well and Annie gas discovery

Analysis and planning of development options for the Otway Basin gas operations is now being conducted within the scope of the Otway Phase-3 Development (OP3D) to identify and deliver the most value-accretive project content, sequence and timing. The immediate opportunities being analysed are the drilling of an additional development well at the Henry gas field and development of the Annie gas discovery.

Annie is currently in the Assess phase, under which resource estimates and preliminary development concepts, expenditure and schedules are being prepared.

Drilling of an additional development well at Henry is expected to enable incremental production of approximately 48 PJ of 2P gas reserves (100% joint venture volume). Volumetric assessments for the Annie gas field, whilst still to be finalised, will provide an input to the Concept Select.

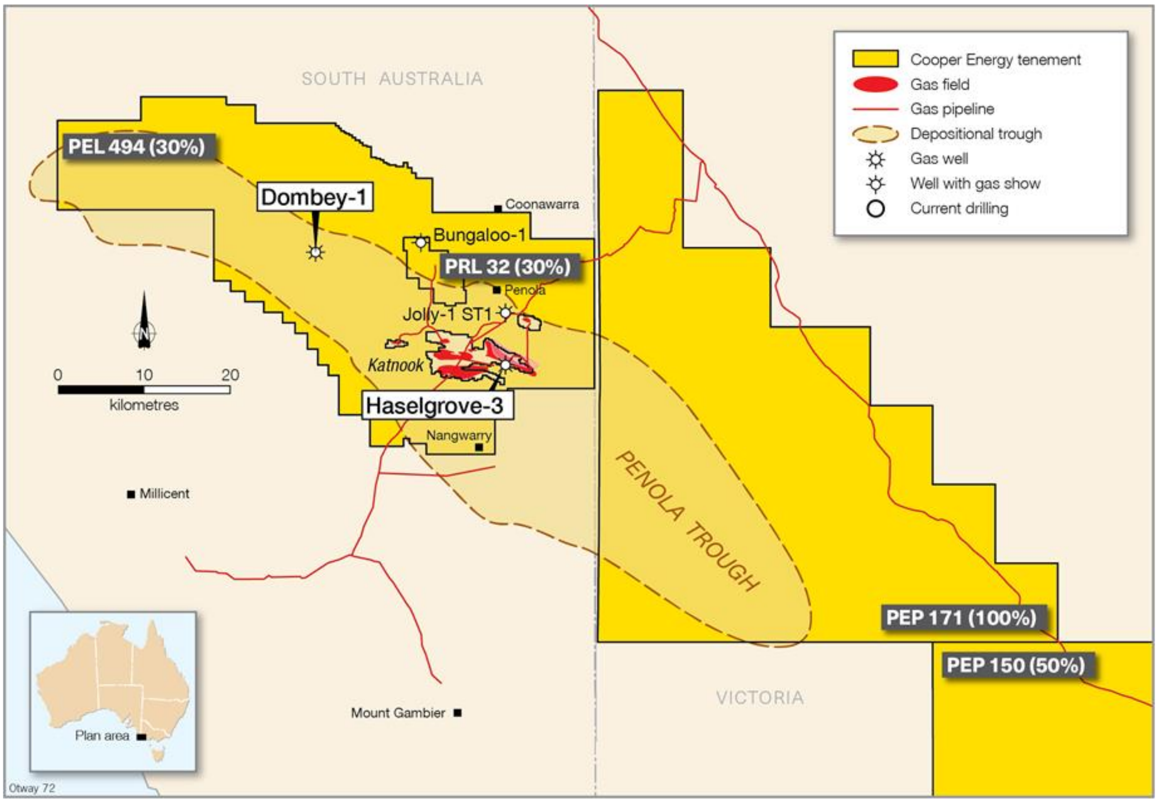
It is expected Annie and Henry will progress to completion of Concept Select in the June quarter in preparation for FID before the conclusion of the calendar year.

Onshore

Cooper Energy's interests in the onshore Otway Basin include licences in South Australia and permits in Victoria. Activities in the latter are currently suspended pursuant to the moratorium on onshore gas exploration until June 2020 imposed by the Victorian state government.

The onshore Otway Basin interests comprise:

1) 30% interests in PEL 494 and PRL 32, South Australia. Beach Energy is the Operator and holds the remaining interest;
2) 50% interests in Bridgeport Energy-operated PEP 150 and Beach Energy-operated PEP 168 in Victoria; and
3) a 75% interest in PEP 171 in Victoria which may reduce by up to a further 25% on fulfilment of farm-in arrangements executed with Vintage Energy Ltd. Vintage Energy is to become Operator pending regulatory approval.



Dombey-1 DW1 recorded a gas discovery well in PEL 494 during the quarter. As announced on 15 October, the well encountered a gross gas column of 44.5 metres, with a net pay thickness of 25 metres, in the Pretty Hill Formation. Gas sample analysis indicates a low inert content.

The production test was performed over the lower 20 metres of the Pretty Hill Formation gas column section. Flow testing occurred over 5 days in December and was followed by a shut-in period of 32 days. The flow test was performed to assess initial deliverability, minimum connected volumes and the presence of any reservoir boundaries. On flow, the maximum measured gas rate exceeded 18 MMscf/d indicating good reservoir productivity. Subsequent decline in flow test pressures during the test indicated potential for the Dombey-1DW1 borehole to be connected to a limited area.

Interpretation of pressure measurements from the extended shut-in indicates re-pressurisation of the reservoir towards initial pre-flow conditions. This suggests potential for a larger gas pool than interpreted by flow test pressures. It is possible Dombey-1DW1 has drilled a small compartment partially connected to a broader accumulation.

The Dombey structure is defined by a limited 2D seismic dataset. As a consequence, the subsurface structural definition is relatively poor. The Joint Venture is considering acquiring 3D seismic data to better define the gas field from which future Dombey appraisal plans, and exploration of the greater permit, may be based.

Dombey-1DW1 is located 20 kilometres north-west of the Katnook Gas Plant. The well was part-funded through a $6.89 million PACE Gas Round 2 grant by the South Australian Government.

Gippsland Basin

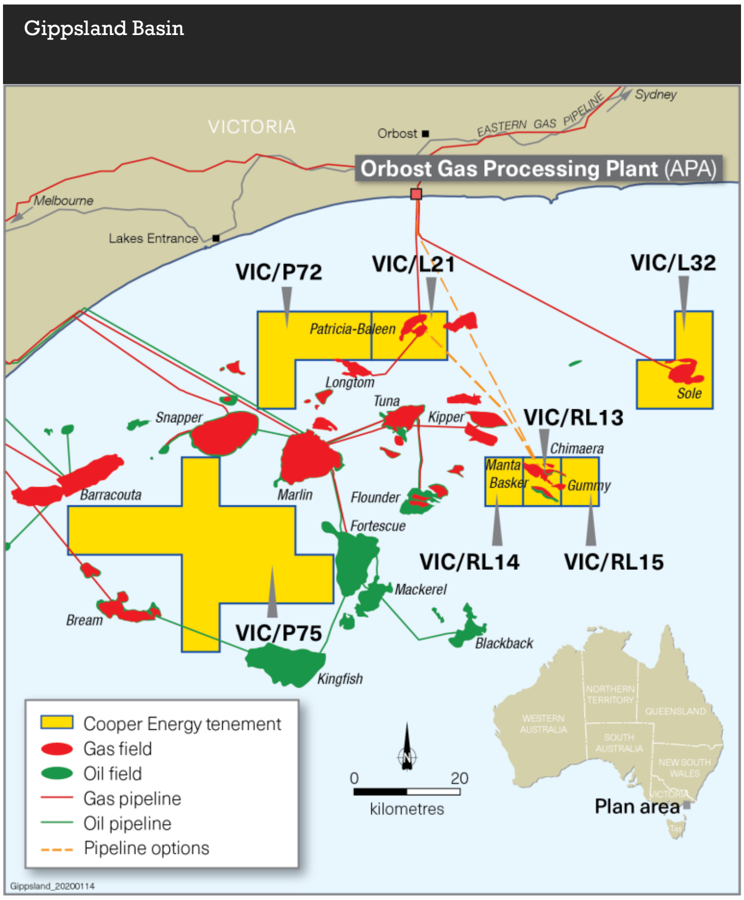
Cooper Energy's interests in the Gippsland Basin include:

a) a 100% interest in, and Operatorship of, production licence VIC/L32, which holds the Sole gas field which has been developed to commence gas supply in the current financial year. Sole is assessed to contain proved and probable reserves of 245 PJ[1] of sales gas;

b) a 100% interest and Operatorship of retention leases VIC/RL13, VIC/RL14 and VIC/RL15 which contain the Manta gas and liquids resource. Manta is assessed to contain Contingent Resources[2] (2C) of 121 PJ of sales gas and 3.4 million barrels of condensate;

c) a 100% interest in, and Operatorship of production licence VIC/L21, which contains the depleted Patricia-Baleen gas field;

d) a 100% interest in and Operatorship of the exploration permits VIC/P72 and VIC/P75.



Development

Sole Gas Project

The Sole Gas Project involves the development of the Sole gas field and upgrade of the Orbost Gas Processing Plant to supply approximately 24 PJ per annum.

Cooper Energy undertook the upstream work to develop and connect the gas field to the Orbost Gas Processing Plant. APA Group is undertaking the upgrade of the Orbost Gas Processing Plant to process gas from Sole.

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[1] Reserves attributable to the Sole gas field were announced to the ASX on 12 August 2019. Cooper Energy is not aware of any new information or data that materially affects the information provided in that release and all material assumptions and technical parameters underpinning the assessment provided in the announcement continues to apply. Refer explanatory notes provided at the end of this report for information on calculation.

[2] Cooper Energy announced its assessment of the Manta Contingent Resource to the ASX on 12 August 2019. Cooper Energy is not aware of any new information or data that materially affects the information provided in that release and all material assumptions and technical parameters underpinning the assessment provided in the announcement continues to apply. Refer notes at the back of this report for information on calculation.

At 31 December the offshore development of the Sole gas project was complete and awaiting completion of the upgrade to APA Group's Orbost Gas Processing Plant.

Commissioning of the plant was interrupted by the bushfires in East Gippsland in December and January. The plant was not damaged, all personnel were kept safe and unharmed and non-essential staff were evacuated from the site. The resumption of work has been spasmodic as protection of workers from ambient smoke has necessitated repeated suspensions of work.

APA advise the introduction of gas from the Eastern Gas Pipeline (EGP) for the first phase of gas commissioning is scheduled to commence prior to mid-February 2020. First gas flow from the field to the plant is now expected to commence in the latter half of February. On this basis, the plant is scheduled to be at full rate production prior to mid-March, subject to satisfactory progress of commissioning. Completion of the plant production test and commercial operation for firm gas supply from Sole is anticipated shortly thereafter. These estimates remain subject to ongoing developments arising from the bushfires including satisfactory air quality for the continuation of site activity.

The delay to plant completion has delayed the commencement of gas supply from Sole to contracts scheduled to begin in January 2020. This has been accommodated through deferral to start dates or through the availability of supply from other sources without penalty to Cooper Energy.

Capital expenditure incurred by Cooper Energy on the offshore project to 31 December 2019 was $347 million, compared to the budgeted P50 estimated project cost of $355 million. The remaining expenditure includes resources to support plant commissioning and start-up and the supply of 'sweet' gas from the pipeline for commissioning. There will also be some adjustments for close-out of some of the contracts associated with the Sole offshore development. The anticipated completion cost remains comfortably within budget.

Manta

The next step in the Manta project is the planning of an appraisal well, Manta-3, which will also test the Manta Deep exploration prospect. Manta-3 is to be optimised for best sequencing within the next offshore drilling campaign, which is expected in 2021, subject to rig availability. Conceptual engineering for a new pipeline and for modifications to the Orbost Gas Processing Plant have been completed.

Exploration

VIC/P72

VIC/P72 adjoins the company's VIC/L21 licence which holds the Patricia-Baleen gas field and its associated subsea production infrastructure connected to the Orbost Gas Processing Plant. The permit is close to several Esso-operated gas and oil fields including Remora, Snapper, Sunfish, Sweetlips and the SGH Energy-operated Longtom gas field.

Interpretation of reprocessed 3D seismic and quantitative interpretation volumes has progressed during the quarter. Prospects identified in VIC/P72 are analogues to offset fields. The prospects identified will be ranked to determine the best drilling target, subject to rig availability, for 2021.

VIC/P75

VIC/P75 was granted on 3 September 2019. The permit is located in the central area of the Gippsland Basin surrounded by major oil and gas fields, including the Marlin, Snapper and Barracouta gas fields to the north and the Kingfish and Fortescue oil fields in the south and east respectively. Good quality 3D seismic data covers most of the permit.

Previous exploration within the VIC/P75 permit area has been impaired by significant depth conversion issues related to velocity complexities above reservoir targets. However, recent advances in 3D seismic reprocessing has provided greater clarity for the mapping of subsurface structures. Applying current reprocessed 3D seismic and Quantitative Interpretation techniques is considered likely to improve mapping of prospects within the permit.

The permit is granted to Cooper Energy for a six-year term, of which the first three years is a guaranteed work program consisting of seismic reprocessing and geological/geophysical studies.

Cooper Basin

The company's Cooper Basin interests during the quarter comprised:

a) a 25% interest in the oil producing PEL 92 Joint Venture operated by Beach Energy which holds the PRLs 85 -104 on the western flank of the Cooper Basin and production licences within this region. The PEL 92 Joint Venture accounted for approximately 96% of the company's oil production for the quarter;

b) a 30% interest in the oil producing PPL 207 ('Worrior') Joint Venture operated by Senex Energy and PRL's 231, 232, 233 and 237 on the western flank of the Cooper Basin; and

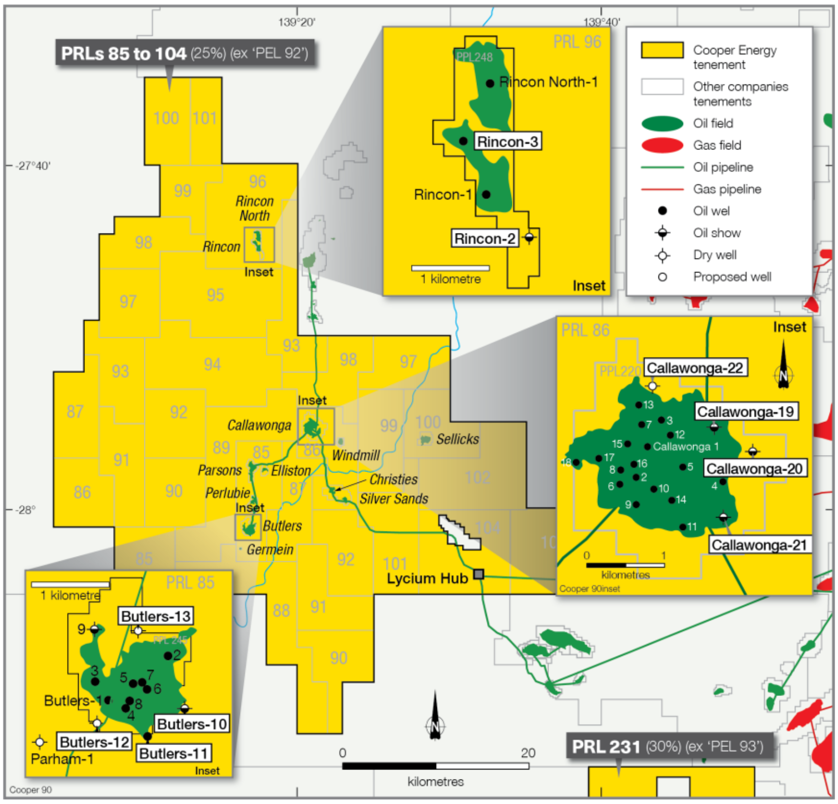
c) interests in northern Cooper Basin exploration licences, PRLs 183 - 190 and PRLs 207 – 209 operated by Senex Energy.

Production

Cooper Energy's share of oil production from its Cooper Basin tenements for the December quarter was 48.1 kbbl (average 523 bopd) compared with 52.1 kbbl (average 567 bopd) in the prior quarter.

Production attributable to Cooper Energy's 25% interest of the PEL 92 Joint Venture in the December quarter accounted for 46.1 kbbl of oil representing an average daily rate of 501 bopd. In comparison, production from PEL 92 averaged 545 bopd in the prior quarter and 615 bopd in the December quarter 2018.

Production from the PPL 207 Joint Venture (Worrior oil field) accounted for the balance of the company's Cooper Basin production. Cooper Energy's share of PPL 207 December quarter production was 2.1 kbbl, in line with the previous quarter.



Exploration and Appraisal

A 10-well oil field appraisal program by the PEL 92 joint venture commenced in November, consisting of four wells at Callawonga, four at Butlers and two at Rincon. Like the preceding Parsons appraisal campaign, the program seeks to enable better definition of field boundaries through targeting wells on field flanks.

Seven wells were completed during the period; four at Callawonga and three at Butlers. The Callawonga appraisal well results were largely in line with pre-drill expectations and have helped define the field limits in the north and east. Callawonga-19, 20 and 21 intersected the top Namur Formation reservoir high to prognosis.

The Butlers field appraisal campaign was completed in early January. Butlers-10 and -11 came in high to prognosis and have identified a potential additional target in the McKinlay Member with moveable oil demonstrated by MDT (Modular formation Dynamic Tester) at Butlers-10. The Namur Sandstone, which is the primary producing reservoir in the field, was shown to be either water-wet or swept in all wells.

The Rincon appraisal program commenced and was completed in January. Rincon-2 was plugged and abandoned and Rincon-3 cased and suspended as a future oil producer. Rincon-3 confirmed connection of the Rincon field between Rincon-1 and Rincon North-1.

Subject to completing full field reviews at Callawonga, Butlers Parsons and Rincon, future development drilling campaigns will be undertaken to increase field production.

In PRL's 231, 232 and 233 (formerly PEL 93), interpretation of the Westeros 3D seismic survey acquired in 2019 has identified several top Namur Sandstone exploration prospects. Plans are progressing for a future test of one prospect, possibly in FY21.

Terms, abbreviations & conversion factors

Terms & abbreviations

$	Australian dollars
2C:	best estimate, contingent resources
2D,3D:	two dimensional, three dimensional
2P	proved and probable reserves
bbl:	barrels
Bcf:	billion cubic feet (of gas)
bfpd:	barrels of fluid per day
Bopd:	barrels of oil per day
Casino Henry:	Casino Henry Netherby
Cooper Energy or “the company”:	Cooper Energy Limited ABN 93 096 170 295 and/or its subsidiaries
FEED:	Front End Engineering and Design
FID	Final Investment Decision
financial year:	12 months ending 30 June 2020
HDD	horizontally directional drill
kbbl:	thousand barrels
km	kilometres
m:	metres
MDRT:	measured depth below rotary table
MM:	million
MMboe:	million barrels of oil equivalent
MMscf/day:	million standard cubic feet per day
n/m:	not meaningful
pcp:	prior corresponding period
PEL:	Petroleum Exploration Licence
PEP:	Petroleum Exploration Permit
PJ:	petajoules
PPL:	Petroleum Production Licence
PRL:	Petroleum Retention Lease
scf:	standard cubic feet (of gas)
SPE PRMS:	Society of Petroleum Engineers Petroleum Resources Management System 2007
the quarter:	three months ended 31 December 2019
TJ:	terajoules

Conversion factors

Gas	1 PJ	= 0.163 MMboe
Oil	1 bbl	= 1 boe
Condensate	1 bbl	= 0.935 boe

Disclaimer and explanatory notes

Disclaimer

The information in this report

- Is not an offer or recommendation to purchase or subscribe for shares in Cooper Energy Limited or to retain or sell any shares that are currently held.
- Does not take into account the individual investment objectives or the financial is not an offer or recommendation to purchase or subscribe for shares in Cooper Energy or to retain or sell any shares that are currently held;
- does not take into account the individual investment objectives or the financial situation of investors; and
- is current as at the date of this report.

Actual results may materially vary from forecasts (where applicable).

Before making or varying any investment in shares of Cooper Energy, all investors should consider the appropriateness of that investment in light of their individual investment objectives and financial situation and should seek their own independent professional advice.

Hydrocarbon Reporting Standard

Cooper Energy reports hydrocarbons in accordance with the SPE PRMS.

Calculation of reserves and resources

Cooper Energy has completed its own estimation of reserves and resources based on:

- in respect of licences operated by Cooper Energy, its own information; and
- in respect of licences operated by third parties, information provided by the permit Operators Beach Energy Ltd, Senex Ltd, and BHP Billiton Petroleum (Victoria) P/L (or their relevant subsidiaries) as applicable,

in accordance with the definitions and guidelines in the SPE PRMS.

Petroleum reserves and contingent resources are typically prepared by deterministic methods with support from probabilistic methods. The resources estimate methodologies incorporate a range of uncertainty relating to each of the key reservoir input parameters to predict the likely range of outcomes. Project and field totals are aggregated by arithmetic summation by category. Aggregated 1P and 1C estimates may be conservative, and aggregated 3P and 3C estimates may be optimistic due to the effects of arithmetic summation.

- **Reserves**

Under the SPE PRMS, reserves are those petroleum volumes that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

The assessment includes Reserves in the Gippsland, Otway and Cooper Basins. Reserves were announced to the ASX on 12 August 2019. Cooper Energy is not aware of any new information or data that materially affects the information provided in that release and all material assumptions and technical parameters underpinning the assessment provided in the announcement continues to apply.

The Otway Basin totals comprise the arithmetically aggregated project fields. The Cooper Basin totals comprise the arithmetically aggregated PEL 92 project fields and the arithmetic summation of the Worrior project Reserves. The Gippsland Basin total comprises Reserves in Sole field only. All Reserves exclude Cooper Energy's share of future fuel usage.

Contingent Resources

Under the SPE PRMS, contingent resources are those petroleum volumes that are estimated, as of a given date, to be potentially recoverable from known accumulations but for which the applied projects are not considered mature enough for commercial development due to one or more contingencies.

The assessment includes Contingent Resources in the Gippsland, Otway and Cooper Basins. Cooper Energy announced its assessment of Contingent Resources to the ASX on 12 August 2019. Cooper Energy is not aware of any new information or data that materially affects the information provided in that release and all material assumptions and technical parameters underpinning the assessment provided in the announcement continues to apply.

Rounding

Numbers in this presentation have been rounded. As a result, some total figures may differ insignificantly from totals obtained from arithmetic addition of the rounded numbers presented.