EDISON

Central Petroleum

Activity poised to gather pace

Business review

Oil & gas

Central Petroleum is at an exciting stage in its development. Work is poised to commence at two joint ventures with world class partners that will provide a major test of the prospectivity of central Australia's Paleozoic basins. The commercialisation of the Surprise field should also start once a production licence has been granted. Selling on a mere A$4.5/acre the stock is modestly valued as an unconventional resource play both from Australian and US perspectives.

Year end	Revenue (A$m)	EBITDA (A$m)	PBT* (A$m)	Debt (A$m)	Net cash/(debt) (A$m)	Capex (A$m)
06/11	0	(37.2)	(36.5)	0	9.5	(0.9)
06/12	0	(25.8)	(25.7)	0	12.1	(1.2)
06/13e	0	(11.2)	(11.4)	0	5.7	(1.0)
06/14e	0	(7.0)	(7.1)	(13.3)	(10.8)	(9.5)

Note: *PBT and EPS are normalised, excluding intangible amortisation, exceptional items and share-based payments.

Surprise field: Recent reserves statement

Central Petroleum (CTP) recently announced an independently assessed statement of reserves for its Surprise discovery in the Amadeus Basin, Northern Territory. The 2P reserves of 1.1mm barrels were at the low end of our range of expectations. However, it should be noted that they only relate to a zone west of a major fault and take no account of the unconventional potential. East of the fault, 2C resources are given as 5.9mm barrels. Commercial production is a possibility by early 2014.

Joint ventures: Farm-outs imminently unconditional

CTP announced two JVs in Q412 with Santos and Total in the Amadeus/Pedirka and South Georgina basins respectively. They cover over 17m acres, almost 30% of the total 58m acres. Exploration outlays of US$340m are planned with around US$90m scheduled over the next 15 months. CTP is free carried on the Santos JV and 80% on the Total JV. CTP does not envisage having to contribute cash under the Total JV until Q314. The JVs will imminently go unconditional.

Financials: 2013 funding requirements underpinned

CTP reported cash at end March 2013 of a modest A$1.8m, but management expects that a series of actions and events may boost this to A$5-6m in the coming weeks. Key factors include cash reimbursements of A$1.6m from farm-in partners, A$1.4m from the disposal of the coal assets and bond refunds associated with exploration programmes. CTP believes funding requirements for calendar 2013 will be underpinned by cash flow.

Valuation: Downgraded from 32c to 28c/share

We have reduced our November 2012 valuation from 32c to 28c/share to reflect a lower than expected 2P reserves estimate for Surprise, a lower cash position and a change in the chances of success assumption for the Wiso acreage. Our valuation is based on a combination of price/acre and DCF-derived price/barrel metrics.

3 May 2013

Price	**A$0.13**
Market cap	**A$187m**

A$0.95/US$

Net cash (A$m)*	5.5
Estimated as at May 2013.	
Shares in issue	1,440.1m
Free float	100%
Code	CTP
Primary exchange	ASX
Secondary exchange	N/A

Share price performance

%	1m	3m	12m
Abs	(12.5)	(16.0)	15.4
Rel (local)	(14.4)	(18.7)	1.8
52-week high/low		A$0.20	A$0.08

Business description

Central Petroleum is an oil and gas junior focused on exploration and development in the basins of central Australia. It currently has exposure to four basins mainly located in the Northern Territory. Two JVs were established in Q412 with Santos and Total.

Next events

Surprise production licence	Q313

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Edison profile page

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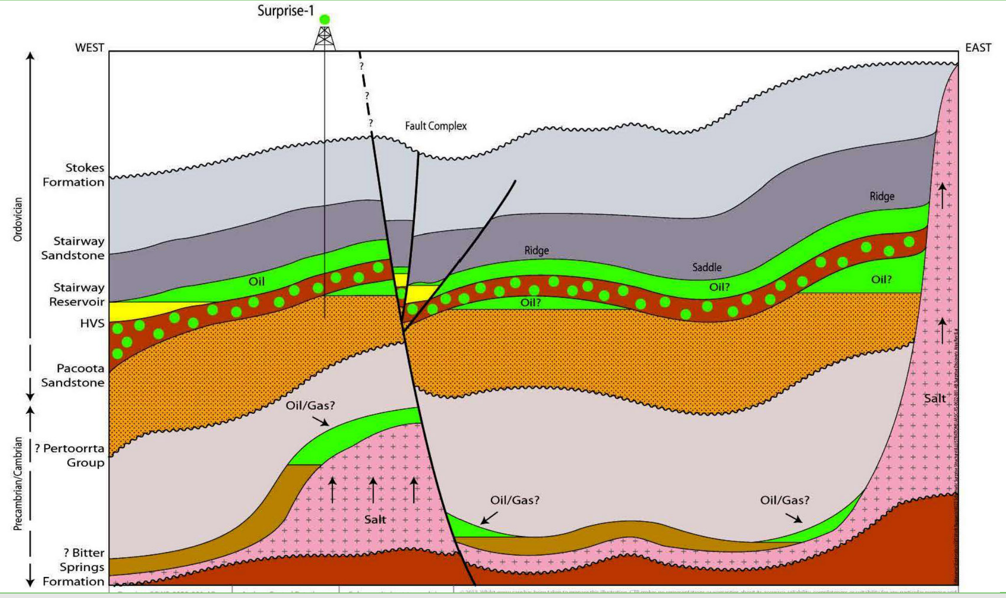
Surprise project

Reserves report: Potentially significant reserve base including contingent resources

CTP announced an oil discovery in early 2012 at its 100% owned Surprise project in the north-western Amadeus Basin of Australia's Northern Territory. The discovery, the first in the Northern Territory in almost 50 years, was made in the Ordovician Stairway Sandstone formation at a depth of about 2,700m. Following an extensive technical assessment, including an extended production test (EPT), a 3D seismic survey, a reservoir modelling exercise and a pressure transient analysis, CTP released at the end of March an independently audited reserves report. The key findings were as follows: 1P 600,000bbls, 2P 1,100,000bbls, 3P 2,125,000bbls. Based on earlier CTP reports, the oil is of very high quality with an API of around 41˚ and low sulphur. During the EPT production stabilised at between 20b/d and 400b/d without a pump, although it should be noted that the purpose of the EPT was to assist in reservoir understanding rather than maximising flow. The peak rate following the discovery was 380b/d.

As currently defined, the reserve base is modest and at the low end of our range of expectations. CTP had previously given a wide P50 OIIP (oil initially in place) range of 4-110mm barrels, which based on a 30% recovery rate would have implied 1.2mm-33mm barrels recoverable. We had assumed an OIIP of 20mm barrels, implying 6mm barrels recoverable as a single point estimate. Two points should be noted concerning the reserves statement. Firstly, the reserves relate only to an area to the west of a major fault, and secondly CTP believes that formations below the Stairway reservoir offer major unconventional potential. Regarding the first point, 2C contingent resources of 5.85mm barrels have been estimated for the zone to the east of the fault. In due course we could therefore be looking at a significantly larger reserve base than currently booked.

Exhibit 1: Surprise discovery schematic



Source: Central Petroleum presentation

Unconventional potential: Horn Valley Siltstone shale oil/gas play

CTP is of the opinion that the Horn Valley Siltstone (HVS), located beneath the Stairway formation and extending for thousands of square kilometres, provides the regional source for known oil and gas discoveries (Mereenie and Palm Valley) in the north-western Amadeus Basin. Based on 3D seismic, CTP believes that the zones straddling the Surprise structure may be highly prospective as an HVS shale oil /gas play. Apparently pressure transient analysis is also pointing to deeper targets in the Pacoota Sandstone and Bitter Springs formations. The plan is to begin appraisal work to test CTP's theory on the deeper targets over the next year or so.

In a recent move, CTP announced that it is the preferred applicant for block L12-2 in Western Australia's zone of the Amadeus Basin. This block links CTP's existing acreage in Western Australia to that in the Northern Territory. The rationale for CTP's interest is to maximise its exposure to the lightly explored western zone of the emerging HVS oil/gas play.

Development plan: Awaiting production licence

As soon as a production licence is issued, CTP intends to begin commercialisation of the Surprise discovery. We believe this could be in Q313 with production possibly following by early 2014. The Field Development Plan that is the basis of the application is currently 80% complete. Initial investment requirements should be relatively small given that roads have already been constructed and a 2,000 barrel storage tank was installed for the extended production test. The key items of equipment required, assuming use of the existing exploration well, will be a pump jack, well tubing, sucker rods and additional oil storage facilities. We believe the incremental investment cost should be less than $5m. Full-scale development of the western zone of the Surprise project would, however, probably be over US$25m assuming another three production wells. Initially, at least, there should be no major logistical infrastructure costs given that oil can easily be trucked off the Surprise property. During the EPT oil was trucked approximately 1,400km south to the Santos refinery at Port Bonython at the head of the Spencer Gulf in South Australia. In total, the Surprise well produced over 10,000 barrels during the EPT. The average realised price was A$124/bbl, which would suggest revenues of A$1.2m.

At this stage any conclusions concerning production rates must be considered highly tentative. Management has intimated that the Surprise well should be capable of operating above the 400b/d reached during the EPT with the use of a pump. Low water production and rapid pressure build-up following the well shut-in are all positive for future oil output rates. Based on this, we might be looking at production rates of over 500b/d but less than 1,000b/d. At present nothing is known about the potential shape of the decline curve.

CTP has also indicated that it is planning a two-well appraisal drilling programme on Surprise. The first well will test the zone to the east of the fault mentioned previously, while the second will be to the west where the targets will be the deep Bitter Springs and Horn Valley Silt formations. The well to the west of the fault will subsequently be used to either produce from the Stairway oil reservoir or as an injector for maintaining pressure in the Surprise discovery well. Procurement planning for a rig and other long lead-time items is underway.

Economics: Potentially attractive netbacks supported by Tapis premium pricing

Any conclusions concerning potential Surprise economics must also be considered highly tentative. However, we know that Surprise currently has at least one key positive from the perspective of economics. This relates to the fact that oil from Surprise, thanks to its very high grade, will sell at premium of about US$10/barrel to the Tapis light oil benchmark. As of early May 2013 this would imply a premium of US$19/barrel to Brent and realisations of about US$118/barrel. This provides the potential for attractive pre-tax netbacks even allowing for high transportation and other operating costs. Significantly, CTP has recently drawn attention to the high costs of operating in remote locations in central Australia and has indicated that operating costs are higher than in established oil producing regions such as the Cooper Basin.

Based on a cursory scoping exercise using realisations of US$118/bbl, we would estimate an operational pre-tax netback before capital costs of US$62-/bbl. This reflects royalty payments of US$18/bbl (Northern Territory 10.0%, native stake holders 5%), transportation of US$18/bbl (shipment to Port Bonython assumed) and operational costs of US$20/bbl (lifting and local G&A). Finding and development costs, we believe, could be in the region of US$20/bbl assuming well and related costs of US$10m and an expected ultimate recovery rate of 500,000 barrels. The fully accounted pre-tax netback might, therefore, be around US$42/bbl. After allowing for the federally levied Petroleum Resource Rent Tax (PRRT) of 40% on reported profits the netback would be reduced to US$25/bbl.

Financing: Open issue presently, project debt finance a possibility

CTP has indicated that it is considering project debt financing for the development of the Surprise property and is currently in discussions with potential facilitators. Conceptually this should be feasible given the potential for early cash flows. Alternatively, CTP has suggested that it is open to joint ventures or an equity raise if market conditions are favourable. However, we do not believe that financing is a paramount issue for Surprise in the near term.

Joint ventures

Arguably, the defining characteristic of CTP is its huge acreage in the largely unexplored but prospective Paleozoic/Mesozoic sedimentary basins of central Australia. Historically, the problem for the company has been how to finance exploration and appraisal activity and unlock potentially substantial resources. The log-jam was broken in the fourth quarter of 2012 with the formation of two farm-out joint ventures with Santos and Total for projects in the Amadeus/Pedirka and South Georgina Basins respectively. The joint ventures in total called for exploration expenditure of approximately US$340m, of which CTP is carried for US$302m. In the 15 months or so to mid-2014 joint venture outlays are expected to be around US$90m. The joint ventures cover about 17m acres or almost 30% of the original total acreage of 58m acres. With 41m net acres, CTP retains comfortably the largest land position in the central Australian sedimentary basins.

The significance of the joint venture deals is that they enable an intensive exploration programme to commence imminently led by world class operators and with a substantial element of free-carry for CTP. To put the spending programme into context, scheduled outlays over the next 15 months or so are broadly equivalent to CTP's expenditure over the last seven years. Importantly, the implied valuations per acre of A$11 and US$37 for the Santos and Total farm-outs respectively were both substantially above the A$4 or so that CTP was trading at in the fourth quarter of 2012. They are also in excess of CTP's valuation at the beginning of the second quarter of 2013 and are in line with or in excess of several recent farm-in deals involving frontier unconventional projects in Central and Western Australia outside the Cooper Basin.

Santos JV: Amadeus/Pedirka basins, CTP free carried

The Santos/CTP joint venture covers about 19.5m acres in the Amadeus/Pedirka Basins of the Northern Territory and envisages exploration outlays of up to A$150m. This will enable Santos to earn a 70% interest in the property. Significantly, CTP will be free-carried and will retain a 100% interest in the approximately 2.4m acres surrounding the Surprise discovery. Santos, of course, is a very experienced operator in central Australia, having been instrumental in the original development of the Cooper Basin in South Australia and Queensland. It is also the operator of the Mereenie and Palm Valley fields in the Northern Territory.

The scheduled work programme has three stages. The first calls for outlays of A$30m over a 15-month period commencing imminently. This follows CTP's recent buy-out of Rawson Resources' 20% interest in the Pellinor Block in the Pedirka Basin. The consideration is 50m shares representing less than 4% of CTP's capital stock. Pellinor, according to CTP, is an attractive prospect that has already been partly de-risked. CTP expects an exploration well to be drilled to test the prospect over the next two years. The Santos JV work programme over the next 15 months or so involves shooting 1,800 km of seismic and drilling one exploration well. At the option of Santos further outlays of A$60m are scheduled for stage 1 and 2 of the exploration programme.

Resources: Based on earlier CTP estimates, the combined resource base of its Amadeus and Pedirka Basin interests is substantial. Gross P50 unrisked resources were put at 5.9mmboe and 1.8mmboe respectively. The former were split 64% unconventional and 36% conventional. About 70% of resources are gas. Pedirka, by contrast, is considered to be a conventional play focused on oil.

Total JV: South Georgina Basin, CTP 80% free carried

The Total farm-out joint venture covers about 6m acres in the South Georgina Basin of south-eastern Northern Territory and western Queensland. A four-year US$190m exploration programme is planned over three phases with CTP free carried for 80% or US$152m. Importantly, Total will finance the first US$48m of phase one with CTP responsible for the next US$12m. CTP has indicated that it does not envisage having to contribute cash to the Total joint venture until Q3 of calendar 2014. Subsequent phases are at the discretion of Total. Assuming completion of the three exploration stages, Total will earn a 68% stake in the project and will operate 90% of the acreage. Total's current interests in Australia revolve around its involvement in the Gladstone (Queensland) and Ichthys (Darwin) LNG projects.

The first stage of the exploration programme is expected to last 18 months from late in the first quarter of 2013 to August 2014. It involves 1,250km of seismic and drilling eight core holes over four permits.

Resources: The South Georgina Basin could potentially be a major source of hydrocarbons based on a Ryder Scott report for TSX-V junior PetroFrontier. The report called for P50 unrisked prospective recoverable resources of 27.5bnboe split 26.4bnboe unconventional and 1.1bnboe conventional. The unconventional estimate would put it into a similar league to the Bakken/Three Forks formation in the Williston Basin of North Dakota. Based on CTP's smaller acreage independent consultant DSWPET has estimated P50 unrisked recoverable resources of 8.0bnboe split 4.0bn barrels oil and 4.0bnboe gas.

Exploration interest in the South Georgina Basin very much reflects its shale potential. The key source rocks are the organic-rich Hot Shales of the Arthur Creek formation, which is of Middle Cambrian age. Significantly, these shales have world class total organic contents averaging over 5% and may be considered analogous to those of the Eagle Ford formation in Texas and the Horn River in British Columbia. The South Georgina Basin has only been very lightly explored but drilling by Pacific Oil & Gas in the 1990s does point to the existence of a functioning petroleum system. PetroFrontier formed a joint venture with Statoil in June 2012 and has drilled three wells using horizontal drilling and multi-stage fracking technology. Indications of hydrocarbons have been found, but arguably the results are a little inconclusive at this stage. Furthermore, PetroFrontier announced at the beginning of December that it was undertaking a strategic review following difficulties in raising finance.

The South Georgina Basin is remote but in the event of a significant discovery there probably should be no difficulty in trucking oil to Port Bonython. Later, if justified by volumes, a load-out facility could probably be built on the Central Australian Railroad. In the event of a large-scale gas find, the two obvious solutions would be to construct tie-ins to the existing Alice Springs to Darwin pipeline and/or to the Cooper Basin processing plants at Moomba (South Australia) and Ballera (Queensland).

Australian Paleozoic basins attract attention

The Paleozoic and Mesozoic sedimentary basins of central and Western Australia have been increasingly attracting the attention of major energy concerns. In addition to CTP's partners, the list includes Hess, ConocoPhillips, Mitsubishi, PetroChina, Statoil, British Gas and most recently Chevron. Beach Energy announced in February 2013 its intention to transfer to Chevron some prime acreage in the Nappamerri Trough unconventional gas zone of the Cooper Basin. The deal could involve payments to Beach of up to US$349m (US$873/acre) over a period of years. Significantly, Beach will retain an interest in the two blocks being transferred. The joint venture deal between Chevron and Beach is the largest so far involving acreage in central Australia.

The growing interest in the central Australian basins reflects their prospectivity as unconventional resource plays along the lines of those in North America and the lightly explored nature of the terrain. Admittedly the Cooper Basin has been producing hydrocarbons since the 1970s, but even here the well density is substantially lower than in comparable mature North American provinces. According to Senex (one of the four major players in the Cooper Basin), the well density in the Cooper Basin is only 2.3/100km^2 against 69/100km^2 in the Permian Basin. The more intensive use of 3D seismic is opening up appraisal opportunities, with the western oil flank of the Cooper Basin a key example.

Coal interests: Sold for A$1.8m

CTP has substantial deep undeveloped coal assets in the Pedirka Basin. The original intention was to develop them as part of a major underground gasification and gas-to-liquids project. At the beginning of April CTP announced its intention to dispose of its coal assets for A$1.8m. The deal is subject to due diligence and completion is scheduled for May 2013. We believe the disposal makes eminent sense given the capital intensity, technical complexity and long lead time required for a GTL project. CTP has also indicated that permit obligations would have required exploration outlay commitments of up to A$10m over the next 12 months in the absence of a divestment.

Financials

Income statement: Cost-cutting and joint ventures to lower central overhead

At the half-year stage in the financial year to June 2013, CTP reported a loss before tax of A$8.9m. This was well down from the A$13m of the previous year, mainly reflecting a sharp drop in exploration outlays (exploration costs are expensed through the income statement rather than capitalised) from A$9.5m to A$4.2m, and income recognition of A$1.5m related to an arbitration claim surrounding an earlier drilling contract. The bulk of the proceeds of perhaps A$1.2m from the sale of oil were also booked in the first half of 2012/13. Receipts from those oil sales were netted off against field operations and transport costs rather than shown as sales revenues. On an EBITDA basis the loss in the first half of 2012/13 was A$7.9m (first half of 2011/12: A$12.2m). Excluding exploration expenditure, the loss at this level would have been A$3.7m (A$2.7m).

During the second half of 2012/13 we would expect the loss at both the EBITDA and PBT levels to narrow significantly. This reflects a combination of cost-cutting, lower exploration outlays and a reallocation of cost to the joint ventures. We would tentatively look for a loss at the EBITDA level of about A$3.3m mainly reflecting residual overhead following the formation of the joint ventures. This would imply an EBITDA loss for 2012/13 of A$11.2m.

For the financial year to June 2014, revenues related to oil sales from the Surprise field are a possibility at some time during the second half. Assuming production of say 600b/d in the fourth quarter of the financial year and realisations of US$118/bbl, we could be looking at around US$6.5m. However, due to uncertainties surrounding development timing we have not included this in the forecast. We would expect CTP’s central overhead in 2013/14 to continue running at the relatively low levels expected in the second half of 2012/13. This would suggest about A$7m at an annual rate and imply a loss at the EBITDA level of a similar amount.

Balance sheet and cash flow: Actions and events set to boost the cash position

CTP reported a cash outflow of almost A$10m in the first half of 2012/13. This largely reflected the EBITDA loss and some modest outlays on exploration assets and plant and equipment, partially offset by interest and GST refunds. As a result of the outflow, the cash position fell from A$12.1m at the end of June 2012 to A$2.1m at the end of December 2012. There was a further decline to A$1.8m by end March 2013. This appears marginal in relation to underlying overheads, but CTP has indicated previously that it is adequately financed to fund operations in calendar 2013. This reflects a combination of initiatives and scheduled events that should boost cash flow in Q4 and reduce the cash-burn in 2012/13. The key factors are as follows:

- CTP is expecting to receive cash reimbursements of A$1.6m from farm-in partners once the farm-outs go unconditional. This is expected to occur imminently.
- CTP is scheduled to receive A$1.4m for the coal assets in May.
- Employees are being redeployed to the joint ventures resulting in a re-allocation of costs.
- A cost-cutting programme was implemented during the six months to December, which has reduced central overhead costs.
- CTP is scheduled to receive refunds of a number of bond monies associated with certain seismic and drilling programmes undertaken in prior years.

After taking into account the above factors along with our second-half EBITDA forecast, we look for a cash position at the end of June 2013 of A$5.7m. This, we believe, will be sufficient to at least cover overheads in the first half of 2013/14. The joint venture projects over this period are, of course, being financed by the farm-in partners.

Under CEO Richard Cottee, CTP has emphasised that it aims to avoid “material dilution unless strategically justified”. Post end-2013, in our view, CTP will probably have to raise equity to finance a combination of corporate overhead, the Surprise development project and possibly its share (US$12m) of the first stage of the Total joint venture in the South Georgina Basin. The amount will be critically dependent on two factors. Firstly, the scale of the Surprise project and whether CTP can obtain debt finance or a joint-venture partner, and secondly, the pace of the exploration at the Total joint-venture project. Our forecasts reflect a net debt position of A$10.8m at the end of June 2014 assuming A$3.5m of development expenditure for Surprise in the second half of 2013/14 and A$6m of outlays related to the Total joint venture. A potential financing route post 31 March 2014 could be exercising the 302.9m of listed options. At the exercise price of A$0.16 these would raise A$48m.

Valuation: Downgrade from 32c to 28c

CTP can be considered a frontier exploration play with major unconventional resources potential. The key industry metric for assessing valuation in these circumstances is enterprise value per acre with the rationale being that shale formations are typically laterally continuous over broad areas. Therefore, once appraisal work has been undertaken in a limited number of zones the findings can be broadly applied across the entire play. On the basis of EV/acre, CTP is undoubtedly modestly valued by US standards, selling on a mere A$4.5/acre. US valuations for early stage unconventional plays might be closer to US$100-200/acre. Even relative to other Australian juniors, CTP is well towards the low end of the valuation range of broadly A$3 to A$40/acre. In looking at this range it should be noted that Australian junior E&P stocks have come under significant pressure since the fourth quarter of 2012.

Exhibit 2: Peer valuation ($/barrel)

Company	Symbol	Operations	Recent production (boe/d)	Enterprise value (A$m)	Reserves mmboe		Resources mmboe		EV/barrel		
					2P	3P	2C	3P+2C	2P	3P	3P+2C
AWE	AWE	Perth Basin/SE Aus/NZ/Texas	14,500	678	54		133.2	133.2	12.6		5.1
Beach Energy	BPT	Cooper Basin	20,548	1507	93		448	448	16.2		3.4
CTP	CTP	Amadeus/Pedirka/ South Georgina/Wiso Basins	0	185	1.1	2.1	5.9	8	168.2	88.1	23.1
Drillsearch	DLS	Cooper/Bonaparte/Otway Basins	7,750	552	18.7	32.1	24	56.1	29.5	17.2	9.8
Senex Energy	SKY	Cooper/Surat Basins	3,588	706	35	75.5			20.2	9.4	

Source: Company reports and Bloomberg

Exhibit 3: Peer valuation (A$/acre)

Company	Symbol	Operations	Enterprise value (A$m)	Net acreage (m)	EV/acre (A$)
Baraka Energy	BKP:AU	South Georgina	6.6	2	3.3
Beach Energy	BPT:AU	Cooper Basin	1507	25	60.3
Buru Energy	BRU:AU	Canning Basin	597	17	35.1
CTP	CTP:AU	Amadeus/Pedirka/South Georgina/Wiso Basins	185	41	4.5
Drillsearch	DLS:AU	Cooper/Bonaparte/Otway	552	4.9	112.7
Icon Energy	ICN:AU	Cooper Basin	66.7	2.1	31.8
PetroFrontier	PFS:TSXV	South Georgina	11	3.5	3.1
Senex	SXY:AU	Cooper/Surat Basins	706	18	39.2

Source: Company reports, Bloomberg

We have modified our November 2012 valuation to allow for the recently announced reserves/resource estimate for Surprise. As before, we have based our valuation for Surprise on a DCF calculation. However, this time our calculation reflects separate estimates for the 2P reserves and the 2C contingent resources weighted by the chances of success. Based on the NPVs of A$16.8m and A$59.5 the implied values per barrel are A$15/bbl and A$10/bbl respectively. After allowing for our estimates of the chance of success, our EMV for Surprise is A$33m. This compares with A$49m previously with the variance reflecting lower assumed reserves/resources and a change in chances of success. Previously we had assumed 6mm barrels weighted by 70% whereas this time we have used 1.1mm barrels of 2P weighted by 90% and 2C contingent resources of 5.9mm weighted by 30%.

For the Amadeus/Pedirka and South Georgina assets we have continued to reflect valuations per acre based on the Santos and Total joint ventures. In the case of the Amadeus/Pedirka acreage outside the Santos joint venture we have included a chance of success of 50%. The Wiso Basin acreage is similar geologically to that of South Georgina but is largely unexplored. In establishing a price per acre for Wiso we have therefore reflected a 70% discount to South Georgina. We have also incorporated a 30% chance of success against 50% earlier. After allowing for development carry plus estimated net cash at April 2013 and general and administrative overhead, our revised

CTP valuation is A$398m or 28c/share. This compares with 32c based on our November 2012 report, with the variance reflecting a combination of the change in Surprise reserves indicated above, a lower cash position and a change in the chances of success assumption for Wiso. On a diluted basis including the listed options we would estimate a valuation of 25.5c/share (diluted share of 1,743m and a A$48m equity raise in the event of exercising 303m options at 16c). The valuation of A$398m equates to A$10/acre, which leaves plenty of scope for valuation upside in the event of exploration success.

Exhibit 4: CTP valuation analysis

FD shares	1,440	CoS	Net acres	NPV/acre	EMV	Value/sh
Permits		**%**	**(millions)**	**A$/acre**	**A$m**	**(A$)**
Amadeus/ Pedirka Basin in STO JV		100%	5.94	10.8	64.3	0.04
Amadeus/ Pedirka Basin not in STO JV		50%	25.4	10.8	137.5	0.10
Southern Georgina Basin post TOT JV		100%	1.9	37.9	71.5	0.05
Wiso Basin		30%	10.7	11.2	36.0	0.02
			Net bbls	**NPV/bbl**		
Assets			**(millions)**	**$/bbl**		
Surprise		90%	1.1	15.2	15.1	0.01
Surprise East upside		30%	5.9	10.1	17.9	0.01
Development carry					63.3	0.04
Net cash/(debt) end 2012					5.5	0.00
G&A					(13.5)	(0.01)
Valuation					**397.6**	**0.28**

Source: Edison Investment Research

Catalysts and risks: The key issues are the Surprise development plan and exploration results

The key potential share price catalysts in the months ahead are likely to revolve around the development plan for Surprise and exploration results relating to the Santos and Total joint ventures. Regarding the former, details may have to await the granting of a production licence, which is not expected until the third quarter of 2013. In the near term, the key risk probably relates to financing. Specifically the issue here concerns uncertainties surrounding the financing of central overhead and Surprise development. It should be noted, however, that CTP believes its funding to be underpinned for calendar 2013 by cash flow associated with the scheduled actions and events mentioned previously. In the medium term, the key issue, of course, relates to joint venture exploration results. At this stage we are not unduly concerned by logistical issues given the relative ease of trucking liquids. Another medium-term issue concerns the possibility of a narrowing of the Tapis premium due to the increasing availability of light crude on world markets.

Exhibit 5: Financial summary

A$'000s	2011	2012	2013e	2014e
30-June	IFRS	IFRS	IFRS	IFRS
PROFIT & LOSS				
Revenue	0	0	0	0
Cost of Sales	0	0	0	0
Gross Profit	0	0	0	0
EBITDA	(37,245)	(25,847)	(11,195)	(7,016)
Operating Profit (before amort. and except.)	(37,510)	(26,164)	(11,583)	(7,216)
Intangible Amortisation	0	0	0	0
Exceptionals	0	0	0	0
Other	(93)	(701)	(1,143)	(1,200)
Operating Profit	(37,603)	(26,865)	(12,726)	(8,416)
Net Interest	959	507	187	100
Profit Before Tax (norm)	(36,550)	(25,657)	(11,396)	(7,116)
Profit Before Tax (FRS 3)	(36,644)	(26,358)	(12,539)	(8,316)
Tax	0	0	0	0
Profit After Tax (norm)	(36,514)	(25,652)	(11,396)	(7,116)
Profit After Tax (FRS 3)	(36,644)	(26,358)	(12,539)	(8,316)
Average Number of Shares Outstanding (m)	963.6	1,157.0	1,440.1	1,440.1
EPS - normalised (p)	(3.8)	(2.2)	(0.8)	(0.5)
EPS - normalised and fully diluted (p)	(3.8)	(2.2)	(0.7)	(0.4)
EPS - (IFRS) (p)	(3.8)	(2.3)	(0.9)	(0.6)
Dividend per share (p)	0.0	0.0	0.0	0.0
Gross Margin (%)	N/A	N/A	N/A	N/A
EBITDA Margin (%)	N/A	N/A	N/A	N/A
Operating Margin (before GW and except.) (%)	N/A	N/A	N/A	N/A
BALANCE SHEET				
Fixed Assets	13,802	13,640	7,181	16,481
Intangible Assets	72	52	44	44
Tangible Assets	11,317	12,269	7,137	16,437
Investments	2,413	1,319	0	0
Current Assets	13,786	14,735	8,656	5,483
Stocks	854	1,051	975	975
Debtors	3,469	1,579	2,008	2,008
Cash	9,464	12,105	5,673	2,500
Other	0	0	0	0
Current Liabilities	(1,643)	(4,089)	(2,658)	(16,237)
Creditors	(1,643)	(4,089)	(2,658)	(2,944)
Short term borrowings	0	0	0	(13,293)
Long Term Liabilities	(50)	(83)	(171)	(1,085)
Long term borrowings	0	0	0	0
Other long term liabilities	(50)	(83)	(171)	(1,085)
Net Assets	25,895	24,204	13,008	4,642
CASH FLOW				
Operating Cash Flow	(35,120)	(21,736)	(7,775)	(7,016)
Net Interest	959	507	187	50
Tax	0	0	0	0
Capex	(903)	(1,184)	(1,025)	(9,500)
Acquisitions/disposals	0	0	1,800	0
Financing	6,998	25,055	381	0
Dividends	0	0	0	0
Net Cash Flow	(28,066)	2,641	(6,432)	(16,466)
Opening net debt/(cash)	(37,530)	(9,464)	(12,105)	(5,673)
HP finance leases initiated	0	0	0	0
Other	0	0	0	0
Closing net debt/(cash)	(9,464)	(12,105)	(5,673)	10,793

Source: Central Petroleum accounts, Edison Investment Research

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