Management Discussion and Analysis of Financial and Operational Performance for the six months ended 31 December 2013

26 February 2014

All figures in this report relate to businesses of the Infigen Energy Group ("Infigen" or "the Group"), being Infigen Energy Limited ("IEL"), Infigen Energy Trust ("IET") and Infigen Energy (Bermuda) Limited ("IEBL") and the subsidiary entities of IEL and IET, for the six months ended 31 December 2013 compared with the six months ended 31 December 2012 ("prior corresponding period") except where otherwise stated.

As required by the International Financial Reporting Standards (IFRS), Infigen consolidates 100% of all controlled entities within its result. Following an IFRS change, which precludes the use of the proportional consolidation method previously employed, Infigen must now account for seven of its US joint ventures using the equity method.

The results discussed in this document refer to Infigen's economic interest unless specifically marked otherwise and therefore minority interests within individual components have been eliminated consistently. All references to $ is a reference to Australian dollars unless specifically marked otherwise. Individual items and totals are rounded to the nearest appropriate number or decimal. Some totals may not add down the page due to rounding of individual components. Period on period changes on a percentage basis are presented as favourable (positive) or unfavourable (negative). Period on period changes to items measured on a percentage basis are presented as percentage point changes ("ppts").

No representation, warranty or other assurance is made or given by or on behalf of Infigen that any projection, forecast, forward-looking statement, assumption or estimate contained in this presentation should or will be achieved.

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1 Statutory Result

1.1 Statutory Loss

Infigen reported a Statutory Loss for the six months to 31 December 2013 of $15.3 million, a favourable movement of $12.5 million compared with a Statutory Loss of $27.8 million in the prior corresponding period (pcp).

The major factors contributing to the result include improved wind conditions in Australia and higher net income from institutional equity partnerships (IEPs) partially offset by an expense related to the termination of interest rate swaps (significant item).

Excluding the significant item, net operating cash flow was up $14.3 million to $37.3 million.

Further details are provided in Section 2.

1.2 Dividends

Following consideration by the Board and as advised by the Chairman of the Board at the 2013 Annual General Meeting, the sweeping of surplus cash flow from operating assets held within the Global Facility Borrower Group effectively serves to continue to preclude the payment of distributions to securityholders.

1.3 Safety

Infigen's first priority is the safety of our people and the communities in which we operate. Our goal is zero lost time incidents and injuries. Infigen's safety performance as measured on a rolling 12 month lost time injury frequency rate (LTIFR) was 3.4 at 31 December 2013 compared with zero at 31 December 2012.

This increase was the result of three lost time incidents during 2013.

These incidents serve as a continuing reminder that we must remain ever vigilant when it comes to safety.

2 Review of Financial Performance

The following tables provide a summary of the key statutory financial outcomes and metrics compared with the relevant prior period.

Six months ended 31 December ($m unless otherwise indicated)	2013	2012 (restated)	Change % F/(A)
Revenue	137.9	122.9	12
EBITDA	80.9	70.5	15
Depreciation and amortisation	(61.4)	(56.9)	(8)
EBIT	19.5	13.6	43
Net borrowing costs	(38.1)	(40.5)	6
FX and interest rate derivative revaluation	(0.7)	(6.2)	88
Net Income from IEPs	17.1	2.8	512
Significant items (interest rate swap terminations)	(16.8)	-	n.m.[1]
Loss before tax	(19.0)	(30.3)	37
Income tax benefit	3.7	2.5	48
Net loss after tax	(15.3)	(27.8)	45

Operating cash flow	14.7	16.7	(12)
Capital expenditure[2]	5.9	7.6	22
Operating cash flow per security[3] (cps)	1.9	2.2	(12)
Earnings per security (cps) [4]	(2.0)	(3.6)	44

Further segmentation of the profit and loss line items in the table above is available in the financial statements and throughout this document.

Position at ($m unless otherwise indicated)	31 Dec 2013	30 Jun 2013 (restated)	Change % F/(A)
Debt	1,134	1,059	(7)
Cash	87	121	(28)
Net debt	1,047	938	(12)
Class A liability	444	450	1
Securityholders' equity	498	484	3
Book Gearing	67.8%	65.9%	(1.9) ppts[5]
Net assets per security ($)	0.65	0.63	3
Net tangible assets per security ($)	0.29	0.28	4

[1] n.m. = not meaningful
[2] Represents the cash outflow in relation to capital expenditure on an economic interest basis
[3] Calculated using securities issued at end of year
[4] Calculated using weighted average issued securities
[5] ppts=percentage points

2.1 Reconciliation of Statutory Accounts to Economic Interest

Infigen has a controlling interest in two wind farm entities in the US in which it owns more than 50% but less than 100% of the Class B interests. Under IFRS, Infigen fully consolidates the financial performance of these wind farm entities within its statutory results and eliminates the non-controlling interest, which is accounted for through "Net Income of IEPs".

Following an IFRS change, which precludes the use of the proportional consolidation method previously employed, Infigen must now account for seven of its US joint ventures using the equity method. For statutory purposes the share of profit of the following US joint ventures is recognised in the "Share of net profits of associates" line item: Sweetwater 1, 2 & 3 (50%), Sweetwater 4 & 5 (53%), Blue Canyon (50%), Combine Hills (50%), JB Wind[6] (59.3%).

Infigen internally reports, and believes that it is more useful to review, the financial performance of the business from an economic interest perspective and has therefore provided a reconciliation between the economic and statutory presentation for the key Profit and Loss line items below.

Following this section all figures included in this report will reference "Economic Interest" unless specifically stated otherwise.

Six months ended 31 Dec 2013 ($ million)	Statutory	Non-controlling Interest	Allocate share of profit of associates	Economic Interest
Revenue	137.9	(7.7)	19.0	149.3
Operating EBITDA	86.4	(4.9)	8.5	90.1
Other costs and income	(11.1)	-	-	(11.1)
Share of net profits of associates	5.5	-	(5.5)	-
EBITDA	80.9	(4.9)	3.0	79.0
Depreciation and amortisation	(61.4)	4.5	(13.7)	(70.6)
EBIT	19.5	(0.3)	(10.7)	8.5
Net borrowing costs	(38.1)	0.1	-	(38.0)
FX and interest rate derivative revaluation	(0.7)	-	-	(0.7)
Net income from IEPs	17.1	0.2	10.7	28.0
Significant items (interest rate swap terminations)	(16.8)	-	-	(16.8)
Loss before tax	(19.0)	-	-	(19.0)
Income tax benefit	3.7	-	-	3.7
Net loss	(15.3)	-	-	(15.3)

[6] Includes the Jersey Atlantic and Bear Creek wind farms

Six months ended 31 Dec 2012 ($ million)	Statutory	Non-controlling Interest	Allocate share of profit of associates	Economic Interest
Revenue	122.9	(6.7)	18.0	134.2
Operating EBITDA	75.2	(4.0)	8.4	79.6
Other costs and income	(8.7)	-	-	(8.7)
Share of net profits of associates	4.0	-	(4.0)	-
EBITDA	70.5	(4.0)	4.4	70.9
Depreciation and amortisation	(56.9)	3.8	(11.9)	(65.0)
EBIT	13.6	(0.1)	(7.6)	6.0
Net borrowing costs	(40.5)	0.2	(0.8)	(41.1)
FX and interest rate derivative revaluation	(6.2)	-	-	(6.2)
Net income from IEPs	2.8	(0.1)	8.4	11.1
Loss before tax	(30.3)	-	-	(30.3)
Income tax benefit	2.5	-	-	2.5
Net loss	(27.8)	-	-	(27.8)

2.2 Significant transactions that occurred in the first half of FY14

On 13 November 2013 Infigen announced that it had entered into agreements to acquire various Class A interests in nine of its US wind farm projects for US$95 million, inclusive of upfront financing costs. The acquired interests are primarily interests in the future cash flows from those projects. The acquisition was financed through utilising US$37 million of Infigen's existing cash holdings and a new US$58 million debt facility provided by Union Bank for a term of 10.5 years. More than 90% of the future interest expense was hedged with interest rate derivatives.

Class A interests in seven of the wind farm projects were acquired by a new investment vehicle that is jointly owned by Infigen and the seller of the Class A tax equity interests. The investment vehicle apportions the vast majority of the cash flows attributable to those interests to Infigen. From an economic perspective, the effective date of the transaction was 31 October 2013.

This transaction is recorded as "investment in financial assets" in Infigen's financial statements and referenced as such throughout this document.

Infigen also purchased 100% of the seller's Class A interests in the Sweetwater 1 and Blue Canyon wind farm projects. Completion of this aspect of the transaction occurred in early January 2014, with an effective date of 1 January 2014 from an economic perspective. As such, this aspect of the transaction has no bearing on the financial information presented herein.

For further information please refer to the ASX release at http://www.infigenenergy.com/investors/asxreleases/infigen-acquires-class-a-interests-in-its-us-portfolio.html

2.3 Management discussion of income statement

Six months ended 31 December ($m unless otherwise indicated)	2013	2012	Change % F/(A)
Revenue	149.3	134.2	11
Operating EBITDA	90.1	79.6	13
Other costs and income	(11.1)	(8.7)	(28)
EBITDA	79.0	70.9	11
Depreciation and amortisation	(70.6)	(65.0)	(9)
EBIT	8.5	6.0	42
Net borrowing costs	(38.0)	(41.1)	8
FX and interest rate derivative revaluation	(0.7)	(6.2)	89
Net Income from IEPs	28.0	11.1	152
Significant items (interest rate swap terminations)	(16.8)	-	n.m.
Loss before tax	(19.0)	(30.3)	37
Income tax benefits	3.7	2.5	48
Net loss after tax	(15.3)	(27.8)	45
Operating cash flow	20.5	23.0	(11)
Capital expenditure[7]	5.9	7.6	22
Operating cash flow per security[8] (cps)	2.7	3.0	(10)
Earnings per security (cps) [9]	(2.0)	(3.6)	44

Foreign exchange rates Average rate for the six months ended	31 Dec 2013	31 Dec 2012	Change %
AUD:USD	0.9214	1.0355	(11)
AUD:EUR	0.6858	0.8113	(15)

Revenue was $149.3 million, up 11% or $15.1 million reflecting higher Australian revenue and a depreciation of the AUD against the USD, partially offset by lower US revenue. Higher production and higher SA merchant electricity prices in Australia, and higher merchant electricity and REC prices in the US were partially offset by lower LGC prices,lower compensated revenue in Australia and lower production in the US.

Operating Earnings Before Interest, Tax, Depreciation and Amortisation (**Operating EBITDA**) was $90.1 million, up 13% or $10.5 million. This was due to:

- Australia: higher revenue partially offset by higher operating costs primarily due to the incentive payments to Vestas resulting from improved availability, production and associated revenue; and

- US: marginally lower revenues described above partially offset by lower asset management and other direct costs.

[7] Represents the cash outflow in relation to capital expenditure
[8] Calculated using securities issued at end of year
[9] Calculated using weighted average issued securities

Development costs expensed were $3.1 million, up $1.3 million primarily reflecting costs of further progressing attractive development opportunities in the US and steady costs in the Australian business.

Corporate costs were $8.0 million, up 4% or $0.3 million. This was primarily due to costs associated with undertaking market testing for the potential sale of Capital wind farm partially offset by lower costs resulting from the organisational restructure and cost saving initiatives announced in February 2013.

Other income in the pcp was $0.8 million and related to an insurance recovery for the replacement of a wind turbine generator in the US.

Depreciation and Amortisation expense was $70.6 million, up $5.6 million primarily due to the depreciation of the AUD against the USD. The expense for the period in Australia increased $1.3 million to $26.2 million compared with the pcp reflecting the reclassification of decommissioning and loan costs to financing costs in the pcp and the write down of some major wind turbine components. In the US the expense decreased to US$40.9 million from US$41.5 million.

Net Borrowing Costs were $38.0 million, down 8% or $3.1 million reflecting lower interest expense due to lower average debt during the period and lower decommissioning provision related costs partially offset by lower interest income and higher amortisation of loan fees.

Six months ended 31 December	2013 ($m)	2012 ($m)	Change % F/(A)
Interest Expense	(35.1)	(36.8)	5
Loan and Bank Fees	(3.4)	(3.1)	(9)
Amortisation of Decommissioning Cost	(0.2)	(2.5)	94
Total Borrowing costs	**(38.7)**	**(42.4)**	**9**
Interest Income	0.7	1.3	(49)
Net Borrowing Costs	**(38.0)**	**(41.1)**	**8**
FX (Loss) / Gain	(1.3)	(5.4)	76
Interest rate derivative revaluation	0.6	(0.8)	175

Net foreign exchange loss of $1.3 million (unrealised) primarily arose due to USD and EUR denominated debt held in Australian companies. This compares with a $5.4 million loss in the pcp following the close out of foreign exchange hedging contracts. The $0.6 million benefit associated with the **interest rate derivative revaluation** reflects a slight increase in benchmark interest rates in the US.

Termination of interest rate swaps resulted in an expense of $16.8 million and was recorded in **significant items**. As a result of hedge accounting, this item had already been reflected in securityholders' equity in prior periods.

Net income from US IEPs was $28.0 million, up $16.9 million compared with income of $11.1 million in the pcp primarily due to the unwind of "benefits deferred". An explanation of the structure of IEPs (including the accounting treatment) is provided in Appendix B of the full year FY13 Management Discussion and Analysis available at infigenenergy.com/investors/publications/financial-results.

Income Tax benefit was $3.7 million compared with $2.5 million in the pcp and is broadly consistent with the loss before tax for the period. The $1.2 million variance was primarily attributable to the pcp including higher US losses for which tax benefits were not recognised due to the uncertainty of recoverability.

Statutory Loss for the six months was $15.3 million, a favourable movement of $12.5 million compared with a Statutory Loss of $27.8 million in the pcp.

3 Cash Flow

3.1 Cash movement

The cash balance at 31 December 2013 was $90.2 million, 27% lower than the $124.0 million balance at 30 June 2013. The cash balance at 31 December 2013 includes $63.8 million held by entities outside ('Excluded Companies') the Global Facility Borrower Group (refer Section 4 for more details).

Cash movements during the period included:

- Investment in financial assets[10] (-$84.9 million);
- Debt reduction (-$10.1 million);
- Distributions to Class A tax equity holders (-$14.2 million);
- Capital expenditure primarily related to capacitor bank installations at Sweetwater, expenditure related to the post-warranty agreements at sites with Gamesa turbines and development activities (-$5.4 million);
- Facility drawdown (investment in financial assets), net of capitalised and expensed loan costs (+$55.8 million);
- Net operating cash flow (+$20.5 million);
- Distributions received from investment in financial assets (+$4.0 million); and
- FX movements (+$0.5 million).

3.2 Net operating cash flow

Six months ended 31 December	2013 ($m)	2012 ($m)	Change % F/(A)
Operating EBITDA	90.1	79.6	13
Corporate, development & other costs	(11.1)	(8.7)	(28)
Working capital & non-cash items	(6.2)	(10.0)	38
Net financing costs and taxes paid	(35.5)	(37.9)	6
Significant item (Interest rate swap terminations)	(16.8)	-	n.m.
Net operating cash flow (NOCF)	**20.5**	**23.0**	**(11)**
Non-controlling interests			
NOCF - associates and JVs	(10.3)	(8.9)	(16)
NOCF - non-controlling interests	4.5	2.5	80
Operating Cash Flow (Statutory)	**14.7**	**16.7**	**(12)**

Net operating cash flow after tax and financing costs was $20.5 million for the six months, down 11% or $2.5 million. Higher EBITDA (refer Section 2), lower net financing costs and taxes paid and lower working capital and non-cash items were offset by $16.8 million in interest rate swap termination costs. The working capital outflow ($6.2 million) is largely attributable to the increased number of LGCs at the balance date accumulated to meet forward sales contracts that were settled in early 2014.

Excluding the significant item net operating cash flow was up $14.3 million to $37.3 million.

[10] Refer section 2.2

4 Capital Management

4.1 Debt

Infigen's borrowings comprise:

- a multi-currency Global Facility secured by Infigen's interests in all of the operational wind farms except for Woodlawn ('the Borrower Group');
- a project finance facility for Woodlawn; and
- a bank facility for which recourse is limited to Infigen's investment in financial assets, subject to certain minor exceptions.

Total debt at 31 December 2013 was $1,134 million (including capitalised loan costs) comprising $1,018 million of Global Facility debt and capitalised loan costs, $51 million of Woodlawn project finance debt and $65 million of financial asset related debt. This was an increase of $74.3 million compared with $1,060 million at 30 June 2013. During the six months to 31 December 2013, $10.1 million was applied to debt amortisation, $62.0 million of financial asset related debt was drawn to fund the investment in financial assets, the depreciation of the AUD against the USD resulted in $27.3 million in unfavourable FX movements with the balance comprising expensed and capitalised loan costs.

The Global Facility leverage ratio covenant was met at 31 December 2013.

4.2 Net Debt

Net debt increased $109 million from $938 million at 30 June 2013 to $1,047 million at 31 December 2013 due to a $34.2 million lower cash balance (refer section 3.1) and $74.3 million higher debt described above.

4.3 Equity

Total equity increased 3% from $484.0 million at 30 June 2013 to $497.9 million at 31 December 2013. The increase of $13.9 million is primarily attributable to the changes in fair value of cash flow hedges (+$27.5 million), exchange differences on translation of foreign operations and movement in fair value (+$0.6 million) and recognition of share-based payments and issue of securities to key management personnel for deferred remuneration (+$1.1 million), partially offset by the net loss for the period (-$15.3 million).

5 Operational Performance Review

5.1 United States

5.1.1 Summary of performance for the half year ended 31 December 2013

Six months ended 31 Dec	2013	2012	Change F/(A)	Change % F/(A)
Total revenue (US$M)	59.4	59.9	(0.5)	(1)
Operating costs (US$M)	36.9	37.2	0.3	1
Operating EBITDA (US$M)	22.4	22.7	(0.3)	(1)
EBITDA margin	37.7%	37.9%		(0.2) ppt
Average price ($/MWh)	44.46	44.30	0.16	-
Operating costs ($/MWh)	27.62	27.51	(0.11)	-
Production tax credit (US$M)	35.1	32.9	2.2	7
EBITDA margin inc PTCs	63.1%	60.4%		2.7 ppt
Translation to AUD				
Revenue (A$M)	64.4	57.8	6.6	11
Operating EBITDA (A$M)	24.3	21.8	2.5	11

Six months ended 31 Dec	2013	2012	Change F/(A)	Change % F/(A)
Operating capacity (MW)	1,089	1,089	-	-
Production (GWh)	1,336	1,352	(16)	(1)
P50 production[11] (GWh)	3,313	3,313	-	-

There was no change to Infigen's operating capacity in the US during the period with operating capacity remaining at 1,089 MW (Class B interest).

Key achievements and outcomes in the US region during the period included:

- Aragonne entered into an agreement to acquire up to 75 MW of firm point to point transmission for 2014 and beyond;
- Activities that will lead to future period revenue enhancement were undertaken, including participating in capacity auctions for certain sites and exploring the potential to obtain capacity injection rights in the PJM market;
- The fire-damaged turbine at Allegheny Ridge was returned to service;
- Allegheny Ridge completed its bird and bat conservation strategy and amended its Co-operator Agreement with the State of Pennsylvania; and
- Steady progress made on transitioning sites with Gamesa turbines over to the original equipment manufacturer for long term service and maintenance.

[11] Annual production

5.1.2 Production

Six months ended 31 December	2013	2012	Change F/(A)
Operating capacity (MW)	1,089	1,089	-
Capacity factor	27.8%	28.1%	(0.3) ppt
Turbine availability	96.2%	96.0%	0.2 ppt
Site availability	95.3%	94.6%	0.7 ppt
Production (GWh)	1,336	1,352	(16)

Production decreased 1% or 16 GWh to 1,336 GWh with mixed wind conditions across the wind farms. The variance primarily reflected lower production due to less favourable wind conditions (Sweetwater 4 and Aragonne), icing on blades (Sweetwater) and lower turbine availability at most wind farms with Gamesa turbines, which were transitioning onto the new warranty agreements. This was partially offset by improved availability and better wind conditions at Cedar Creek, improved availability at Caprock and better wind conditions at Kumeyaay.

Turbine availability improved 0.2% to 96.2% due to proactive maintenance and the return to service of some turbines. Site availability increased 0.7% to 95.3% due to the non-recurrence of scheduled substation maintenance that occurred in the pcp.

5.1.3 Price

The average portfolio price realised increased marginally to US$44.46/MWh compared with US$44.30/MWh. This was due to higher realised electricity and REC prices from merchant wind farms partially offset by unfavourable imbalance (scheduling) charges.

The time weighted average electricity prices for the markets in which Infigen has merchant assets are outlined below.

Six months ended 31 December (US$/MWh)	2013	2012	Change % F/(A)
PJM - AECO	36.9	37.2	(1)
PJM - CE	29.6	30.0	(1)
ERCOT - W	32.0	24.7	29

5.1.4 Revenue

Revenue decreased 1% or US$0.5 million to US$59.4 million. This primarily reflected a net decrease in production due to the factors described earlier as well as reduced price at Crescent Ridge since its PPA expired in June 2013, partially offset by higher merchant electricity and REC prices.

5.1.5 Operating costs

Operating costs decreased 1% or US$0.3 million to US$36.9 million reflecting improved operating and maintenance practices.

- Asset management costs (including IAM[12] costs) decreased US$0.5 million to US$6.6 million primarily reflecting lower legal costs and lower IAM costs following the resolution of the Gamesa dispute, and savings following the organisational restructure and cost savings initiatives implemented in early 2013 partially offset by transaction costs associated with the acquisition of Class A interests[13] (US$0.7 million);
- Turbine O&M costs increased US$0.7 million primarily due to the commencement of the Gamesa extended warranty agreements entered into in June 2013;
- Balance of plant costs increased US$0.4 million due to collection system maintenance at Crescent Ridge and overhead power line maintenance at Cedar Creek; and
- Other direct costs decreased US$1.0 million reflecting a one-off decrease in transmission fees at Aragonne (US$0.4 million) and lower property taxes and insurance expenses at Sweetwater 5 and Cedar Creek (US$0.6 million).

Six months ended 31 Dec (US$M)	2013	2012	Change F/(A)	Change % F/(A)
Asset Management	6.6	7.1	0.5	7
Turbine O&M	17.7	17.0	(0.7)	(4)
Balance of Plant	4.0	3.6	(0.4)	(11)
Other Direct Costs	8.5	9.5	1.0	11
Operating Costs	**36.9**	**37.2**	**0.3**	**1**

5.1.6 Operating EBITDA

Operating EBITDA for the US business decreased 1% or US$0.3 million to US$22.4 million primarily reflecting lower wind farm revenue partially offset by lower operating costs across the business.

EBITDA margin was 37.7% compared with 37.9% in the pcp, while EBITDA margins including PTCs improved from 60.4% to 63.1% primarily due to the timing of the recognition of PTC income.

5.1.7 Development

Work continued on the solar PV development pipeline during the period including advancing the Wildwood I and Pumpjack projects to be in a position to start construction by the end of the 2014 calendar year.

The development team completed interconnection studies for the Rio Bravo I and Wildwood II opportunities, and initiated the development of additional solar PV projects in New York and California.

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[12] Infigen Asset Management

[13] These costs should not be considered part of the on-going costs associated with the operations of the wind farms. These costs were incurred by 'Excluded Companies'.

5.2 Australia

5.2.1 Summary of performance for the half year ended 31 December 2013

Six months ended 31 Dec ($M) unless stated otherwise	2013	2012	Change F/(A)	Change % F/(A)
Revenue	84.9	76.4	8.5	11
Operating EBITDA	65.8	57.8	8.0	14
Operating EBITDA margin	77.5%	75.6%		1.9 ppts
Average Price (A$/MWh)	93.7	94.4	(0.7)	(1)
Operating Cost (A$/MWh)	21.1	23.0	1.9	8

Six months ended 31 Dec	2013	2012	Change F/(A)	Change % F/(A)
Operating capacity (MW)	557	557	-	-
Production (GWh)	906	810	96	12
P50 production[14] (GWh)	1,606	1,606	-	-

There was no material change to Infigen's operating capacity in Australia during the period with operating capacity increasing by 0.1 MW to 556.7 MW following completion of the Capital East solar demonstration facility.

Key achievements and outcomes during the period included:

- **Strong production** driven by improved wind conditions and improved balance of plant reliability across the portfolio.

- **Capital East solar demonstration facility** - The first stage (approximately 130 kW) of the facility was completed and registered as a generator with AEMO in September 2013.

- **Stable and improving operating performance** driven by:
  - improved turbine and balance of plant availability;
  - favourable realised electricity prices; and
  - enhanced use of wholesale and financial market instruments to hedge merchant electricity and LGC revenue.

5.2.2 Production

Six months ended 31 Dec	2013	2012	Change F/(A)
Operating Capacity (MW)	557	557	-
Capacity Factor	36.9%	32.9%	4.0 ppt
Turbine Availability	97.7%	97.5%	0.2 ppt
Site Availability	97.6%	96.6%	1.0 ppt
Production (GWh)	906	810	96

Production increased 12% or 96 GWh to 906 GWh. The pcp included 27 GWh of compensated production related to the settlement of an AEMO scheduling error. Excluding this the variance of 123 GWh reflected better wind conditions (+130 GWh),

[14] Annual production

improved balance of plant reliability (+5 GWh) and lower network losses (+6 GWh), partially offset by less favourable wind conditions at Alinta (-16 GWh) and higher turbine downtime (-2 GWh) during periods of good wind conditions, notwithstanding improved availability.

Turbine availability and site availability improved 0.2% and 1.0% respectively.

Network constraints are limitations of the transmission network which can reduce Infigen's production for which Infigen receives no compensation. Network constraints were lower than the pcp with an improvement in the network availability at Alinta wind farm (+11 GWh), offset by lost production due to increased thermal constraints, planned line outages and high voltage equipment maintenance at Lake Bonney 2 and 3 (-4 GWh).

5.2.3 Prices

Electricity

The time weighted average (TWA) electricity prices changed marginally compared to the pcp, increasing 6% in SA and decreasing 4% in NSW.

Six months ended 31 December TWA wholesale electricity ($/MWh)	2013	2012	10 Year Average
SA (Lake Bonney)	64.94	61.09	49.18
NSW (Capital & Woodlawn)	54.33	56.71	42.89

Infigen's dispatch weighted average (DWA) electricity prices increased 8% to $57.83/MWh in SA and remained flat at $55.17/MWh in NSW. The prices broadly correlate with the TWA price variations in each region.

Average spot prices in Australia can be significantly influenced by short term extreme price events. Wholesale electricity spot prices can vary between the market price floor of -$1,000/MWh and the market price cap of $13,100/MWh.

During H1 FY14 volatility resulted from competitive bidding, plant failures, low wind, high demand and transmission constraints unlike the pcp where the main reason for volatility was extended maintenance on Victorian transmission lines that affected the Heywood interconnector and low wind production in SA. Volatility had little bearing on the period on period variance in the dispatch weighted average price.

Large-scale Generation Certificates (LGCs)

Six months ended 31 December ($/MWh)	2013	2012	Change % % F/(A)
Large-scale Generation Certificates	36.44	36.66	(1)

The average monthly LGC price for the six months decreased 1% to $36.44/LGC compared to $36.66/LGC in the pcp. The closing LGC price at 31 December 2013 was $33.00/LGC compared with $37.20/LGC at 31 December 2012.

At 31 December 2013 Infigen held approximately 428,000 LGCs with a book value of $15.9 million compared with approximately 312,000 LGCs with a book value of $11.4 million at 31 December 2012. These LGCs were recognised in the revenue line at the lower of weighted average market price and the end of month market price for the month in which they were created.

Reported revenue included $7.1 million related to LGCs that were created but not sold during the period compared with $1.3 million in the pcp.

Bundled pricing

Infigen's weighted average portfolio bundled (electricity and LGCs) price was 1% lower at $93.7/MWh compared to $94.4/MWh in the pcp due to lower LGC prices. Of Infigen's six operational Australian wind farms 55% of annual P50 production is currently contracted under medium and long term agreements.

5.2.4 Revenue

Revenue increased 11% or $8.5 million to $84.9 million as a result of higher production (+$11.2 million), and higher SA electricity prices (+$2.0 million), offset by lower LGC prices (-$2.2 million), lower contracted revenue from Sydney Desalination Plant (-$1.1 million), lower NSW electricity prices (-$0.2 million) and lower compensated revenue (-$1.2 million).

5.2.5 Operating Costs

All of Infigen's Australian wind turbines are covered by either their Original Equipment Manufacturer's warranty (Suzlon) or post-warranty service agreements (Vestas). This is contributing to improved stability and predictability of wind farm costs.

Six months ended 31 Dec ($M)	2013	2012	Change F/(A)	Change % F/(A)
Asset Management	3.2	3.5	0.3	9
Turbine O&M	10.2	8.7	(1.5)	(17)
Balance of Plant	0.5	0.4	(0.1)	(25)
Other Direct Costs	3.7	3.7	-	-
Wind Farm Costs	**17.6**	**16.3**	**(1.3)**	**(8)**
Energy Markets	1.6	2.3	0.8	33
Operating Costs	**19.1**	**18.6**	**(0.5)**	**(3)**
Total Operating Costs $/MWh	*21.19*	*22.96*	*1.77*	*8*

Total operating costs increased 3% or $0.5 million to $19.1 million. The key variances include:

- Higher turbine O&M costs due to the production and availability linked incentive mechanism within the Vestas post-warranty agreements (+$1 million) and minor blade repair work at Alinta for damage caused by lightning strikes (+$0.5 million);
- Slightly higher balance of plant equipment costs at Lake Bonney (+$0.1 million);
- Lower asset management costs resulting from the organisational restructure and cost saving initiatives undertaken in early 2013 (-$0.3 million); and
- Higher CPI linked land lease and connection costs (+$0.2 million) were offset by lower insurance costs (-$0.2 million).

- Energy Markets costs were $0.8 million lower than the pcp due to lower hedging costs and lower professional fees (-$0.7 million) and lower costs as a result of the organisational restructure (-$0.1 million).

5.2.6 Operating EBITDA

Operating EBITDA increased 14% or $8.0 million to $65.8 million reflecting higher revenue from higher production and higher average merchant electricity prices, partially offset by lower LGC prices and slightly higher operating costs.

Operating EBITDA margin for the period was 77.5% compared to 75.6% in the pcp.

5.2.7 Development

Development Approvals

The Bodangora and Cherry Tree wind farm developments received development consent in September and November 2013 respectively. Infigen's proposed Flyers Creek wind farm was referred to the NSW Planning Assessment Commission for determination in November 2013.

Commissioning of Capital East Solar Farm

During the period Infigen commissioned the first stage of the Capital East solar farm, a solar photovoltaic (PV) and energy storage demonstration facility (approximately 130 kW) including 10 kW of solar modules from several different suppliers. The experience gained from this project will benefit future large-scale solar PV projects.

6 Outlook

Consistent with long-term seasonal variation, second half production is expected to increase in the US and decrease in Australia.

In the US, similar merchant electricity prices in the PJM and ERCOT markets are expected for the remainder of FY14. In Australia, slightly higher bundled prices are expected in the second half due to seasonal variations and forward contracted LGC sales.

Full year operating costs in the US and Australia are expected to remain within the US$73-76 million and A$35-37 million guidance ranges respectively.

Subject to these operating conditions, Infigen is currently on track to exceed its guidance of having approximately $80 million of cash flow available to repay Global Facility borrowings, distribute to Class A tax equity members and close out interest rate swaps in FY14.

Infigen's investment in financial assets (the US Class A interests) will generate additional cash flow to Infigen.

7 Appendix A – Balance Sheet by Country

A$ million as at 31 December 2013	IFN Statutory Interest	Less US Minority Interest	Add: US Equity Accounted Investments	Economic Interest	Australia	United States
Cash	87.1	(0.6)	3.7	90.2	60.0	30.2
Receivables	30.9	(1.8)	4.0	33.0	18.1	15.0
Inventory & LGCs	18.2	(0.2)	1.2	19.2	14.5	4.7
Prepayments	16.2	(0.3)	2.0	18.0	7.5	10.5
PPE	2,002.1	(162.4)	472.8	2,312.6	896.2	1,416.3
Goodwill & intangibles	275.3	(9.7)	(3.7)	261.9	135.1	126.8
Deferred tax & other assets	51.9	-	-	51.9	53.8	(1.9)
Investments in Associates	102.1	-	(101.2)	0.9	0.9	-
Investment in financial asset	84.7	-	-	84.7	-	84.7
Total assets	**2,668.6**	**(174.9)**	**378.7**	**2,872.3**	**1,186.0**	**1,686.3**
Payables	28.9	(2.6)	5.0	31.3	11.6	19.7
Provisions	22.0	(2.0)	7.9	27.9	10.4	17.5
Borrowings	1,134.3	-	1.5	1,135.8	726.8	409.0
Tax Equity (US)	499.2	(117.6)	208.2	589.8	-	589.8
Deferred revenue (US)	361.3	(52.7)	156.0	464.6	-	464.6
Interest rate derivative	125.0	-	-	125.0	93.2	31.8
Total Liabilities	**2,170.7**	**(174.9)**	**378.7**	**2,374.5**	**842.0**	**1,532.5**
Net assets	**497.9**	**-**	**-**	**497.9**	**344.0**	**153.8**

Foreign exchange rates As at	31 Dec 2013	31 Dec 2012	Change %
USD	0.8922	1.0378	(14)
EUR	0.6474	0.7868	(18)

8 Appendix B – Institutional Equity Partnerships

8.1 Wind farm portfolio

2003/04	2005	2006	2007
Sweetwater 1 & 2	Sweetwater 3	Aragonne Mesa	Sweetwater 4 & 5
Caprock	Kumeyaay	Buena Vista	Cedar Creek
Blue Canyon	Jersey Atlantic	Mendota Hills	
Combine Hills	Bear Creek	Allegheny Ridge	
	Crescent Ridge	GSG	

8.2 IEP summary for the six months ended 31 December 2013

8.2.1 Production (GWh) by asset vintage

Six months ended 31 Dec	2013	2012	Change F/(A)	Change % F/(A)
2003/2004	334	340	(6)	(2)
2005	211	209	2	1
2006	323	342	(19)	(6)
2007	467	461	6	1
Total	**1,336**	**1,352**	**(16)**	**(1)**

8.2.2 Revenue (US$ million) by asset vintage

Six months ended 31 Dec	2013	2012	Change F/(A)	Change % F/(A)
2003/2004	10.0	10.2	(0.2)	(2)
2005	8.7	9.9	(1.2)	(12)
2006	17.9	17.9	-	-
2007	22.8	21.9	0.9	4
Total	**59.4**	**59.9**	**(0.5)**	**(1)**

8.2.3 Profit and loss (US$ million) by asset vintage

Six months ended 31 Dec 2013	2003/04	2005	2006	2007	Total
Revenue	10.0	8.7	17.9	22.8	59.4
Costs	(6.1)	(6.0)	(12.9)	(8.5)	(33.5)
EBITDA	3.9	2.7	5.0	14.2	25.9
D&A	(6.7)	(7.4)	(16.3)	(17.2)	(47.8)
EBIT	**(2.8)**	**(4.7)**	**(11.3)**	**(3.0)**	**(21.9)**

8.2.4 Class A capital balance amortisation (US$ million) by asset vintage

Six months ended 31 Dec 2013	2003/04	2005	2006	2007	Total
Opening Balance (1 Jul 13)	**51.4**	**86.9**	**153.5**	**230.2**	**522.0**
Production Tax Credits	(8.2)	(5.9)	(8.4)	(12.5)	(35.0)
Tax (losses)/ gains	1.6	1.2	-	3.6	6.4
Cash distributions	(3.7)	(2.8)	-	(6.5)	(13.0)
Allocation of return (interest)	1.1	3.3	5.0	7.1	16.5
Closing Balance (31 Dec 13)	**42.2**	**82.7**	**150.1**	**221.8**	**496.8**

8.3 IEP summary for the year ended 30 June 2013

8.3.1 Production (GWh) by asset vintage

Year ended 30 June	2013	2012	Change F/(A)	Change % F/(A)
2003/2004	722	716	6	1
2005	509	519	(10)	(2)
2006	776	820	(44)	(5)
2007	1,082	1,081	1	-
Total	**3,089**	**3,136**	**(47)**	**(1)**

8.3.2 Revenue (US$ million) by asset vintage

Year ended 30 June	2013	2012	Change F/(A)	Change % F/(A)
2003/2004	22.5	22.8	(0.3)	(1)
2005	24.6	25.9	(1.3)	(5)
2006	42.6	43.7	(1.1)	(3)
2007	53.1	51.5	1.6	3
Total	**142.9**	**143.9**	**(1.0)**	**(1)**

8.3.3 Profit and loss (US$ million) by asset vintage

Year ended 30 June	2003/04	2005	2006	2007	Total
Revenue	22.5	24.6	42.6	53.1	142.9
Costs	(12.5)	(13.6)	(28.1)	(20.5)	(74.8)
EBITDA	10.0	11.0	14.8	32.6	68.4
D&A	(11.8)	(12.9)	(26.9)	(29.6)	(81.3)
EBIT	**(2.0)**	**(2.0)**	**(12.1)**	**3.2**	**(12.9)**

8.3.4 Class A capital balance amortisation (US$ million) by asset vintage

Year ended 30 June	2003/04	2005	2006	2007	Total
Closing Balance (30 Jun 12)	65.8	95.1	162.0	238.6	561.5
Tax true-up	(0.1)	0.3	(0.1)	(0.7)	(0.6)
Opening Balance (1 Jul 12)	**65.7**	**95.4**	**161.9**	**237.9**	**560.9**
Production Tax Credits	(16.2)	(11.7)	(18.7)	(24.4)	(71.1)
Tax (losses)/ gains	3.5	2.6	0.2	0.9	7.1
Cash distributions	(7.4)	(6.6)	-	-	(13.9)
Allocation of return (interest)	5.8	7.2	10.1	15.8	38.9
Closing Balance (30 Jun 13)	**51.4**	**86.9**	**153.5**	**230.2**	**522.0**

8.4 US cash distributions

Cash flows from the US business are split between the Class A and Class B members in accordance with their entitlements during the various stages of the wind farms' lives (refer Appendix B of the Management Discussion and Analysis for the year ended 30 June 2013 for more detail).

Cash flow allocated to Class A members during the period was US$13.0 million compared with US$5.0 million in the pcp. This relates to the Blue Canyon, Combine Hills, Caprock, Crescent Ridge, Jersey Atlantic, Bear Creek, Cedar Creek, Kumeyaay and Sweetwater 1-3 wind farms, where the Class A members will receive all net operating cash flow from those wind farms until their capital balances including agreed return, are fully amortised (refer below for Class A capital balances).

The following table provides a summary of Class A capital balance movements.

Economic Interest Class A Capital Balance by vintage (US$ million)				
As at	31 Dec 2013	30 June 2013	Change F/(A)	Change % F/(A)
2003/2004	42.2	51.4	9.2	18
2005	82.7	86.9	4.2	5
2006	150.1	153.5	3.4	2
2007	221.8	230.2	8.4	4
Total	**496.8**	**522.0**	**25.2**	**5**

The following table provides a summary of Class B capital balance movements.

Economic Interest Class B Capital Balance by vintage (US$ million)				
As at	31 Dec 2013	30 June 2013	Change F/(A)	Change % F/(A)
2003/2004	-	-	-	-
2005	4.2	4.2	-	-
2006	100.3	104.3	4.0	4
2007	37.8	44.4	6.6	15
Total	**142.3**	**152.9**	**10.6**	**7**

Class B capital balances are held at the limited liability company (LLC) level (refer Appendix B of the Management Discussion and Analysis for the year ended 30 June 2013 for the relationship between wind farms, LLCs and asset vintage). Once Class B capital balances are fully repaid (cash flip point) or a fixed (cash cut-off) date is reached (whichever occurs earlier), all operating cash flow from the related wind farm assets is allocated to Class A members until their capital balances are fully amortised and agreed return achieved.

All wind farm entities in the 2003/2004 and 2005 vintage portfolio are distributing cash to the Class A members.

The 2006 vintage portfolio will begin to distribute cash to the Class A members no later than the end of November 2015.

In the 2007 vintage portfolio Cedar Creek reached its cash flip point in August 2013 after having its Class B capital balance repaid ahead of investment case expectations. The other wind farms in the 2007 portfolio are Sweetwater 4 & 5, which will begin to distribute cash to the Class A members no later than the end of April 2015.

Once the Class A members achieve their agreed target return, the cash flows are reallocated between the Class A and Class B members. The Blue Canyon and Combine Hills wind farms are currently expected to return to distributing cash to Infigen as Class B member no later than December 2016 with the Crescent Ridge and Caprock wind farms expected to follow in June 2018 and December 2017 respectively.

The combined effect of the factors described above on Infigen's portfolio of 18 US wind farms is that the aggregate distributions to Infigen as Class B member diminish as more projects reach the cash flip point or cash cut-off date (whichever occurs earlier) and more operating cash flow is directed to reducing Class A capital balances. Infigen's aggregate distributions will therefore 'dip' for a period until projects in the portfolio begin to reach their reallocation dates. For Infigen's portfolio, the cash flow dip is currently expected to be most pronounced from the second half of FY16 through to the first half of FY18. The timing and duration of the cash flow dip will be influenced by the performance of the US wind farms during the intervening period.

The following table summarises the components of net income from IEPs on a Statutory basis in USD and eliminates the minority interest to derive an economic interest.

Six months ended 31 December	2013 (US$m)	2012 (US$m)	Change % F/(A)
Value of production tax credits (Class A)	25.6	24.2	6
Value of tax expense/credit (Class A)	(6.7)	1.8	(479)
Benefits deferred during the period	8.6	(2.2)	499
Income from IEPs	**27.4**	**23.9**	**15**
Allocation of return (Class A)	(12.4)	(13.5)	8
Movement in residual interest (Class A)	2.2	(7.4)	129
Non-controlling interest (Class B)	(1.6)	-	n.m.
Financing costs related to IEPs	**(11.8)**	**(20.9)**	**44**
Net income from IEPs (Statutory)	**15.6**	**2.9**	**436**
Non-controlling interests (Class B & Class A)	9.9	8.7	13
Net income from IEPs (Economic Interest)	**25.5**	**11.7**	**119**

The following table summarises the components of net income from IEPs on a Statutory basis in AUD and eliminates the minority interest to derive an economic interest.

Six months ended 31 December	**2013 (A$m)**	**2012 (A$m)**	**Change % F/(A)**
Value of production tax credits (Class A)	27.8	23.2	20
Value of tax expense/credit (Class A)	(7.3)	1.7	(529)
Benefits deferred during the period	9.3	(2.1)	543
Income from IEPs	**29.8**	**22.8**	**31**
Allocation of return (Class A)	(13.5)	(12.9)	(5)
Movement in residual interest (Class A)	2.5	(7.1)	135
Non-controlling interest (Class B)	(1.7)	-	n.m.
Financing costs related to IEPs	**(12.7)**	**(20.0)**	**37**
Net income from IEPs (Statutory)	**17.1**	**2.8**	**514**
Non-controlling interests (Class B & Class A)	10.9	8.4	31
Net income from IEPs (Economic Interest)	**28.0**	**11.1**	**152**

Value of Production Tax Credits (PTCs) (Class A) was $27.8 million, up 20% or $4.6 million largely reflecting lower production and the depreciation of the AUD against the USD and the higher PTC rate in the 2013 calendar year. The unit value of a PTC was US$23 per MWh for the 2013 calendar year and US$22 per MWh for the 2012 calendar year.

Value of tax expense (Class A) was $7.3 million, down 529% or $9.0 million due to the reduction in tax depreciation as assets that benefit from accelerated depreciation become fully depreciated.

During the period $9.3 million of benefits were deferred, up 543% or $11.4 million. Benefits deferred are the difference between tax depreciation and accounting depreciation for the year. This reduction reflects lower tax depreciation during the period as described above.

Allocation of return (Class A) is the agreed target return on Class A capital balances and was a $13.5 million expense for the period, up 5% or $0.6 million reflecting both lower Class A capital balances and the depreciation of the AUD against the USD.

The movement in residual interest (Class A) was $2.6 million. This reflects period on period changes in expectations of future tax allocations and cash flows.

The non-controlling interest (Class B) represents the share of net profit attributable to the non-controlling interest holders in the Cedar Creek and Crescent Ridge wind farms. The increase was primarily due to a higher net income from IEPs for those wind farms.

The non-controlling interest (Class B & Class A) represents the elimination of non-controlling interest contributions of each income and financing cost IEP line item (attributable to both the Class A and Class B non-controlling interests in the Cedar Creek and Crescent Ridge wind farms).