Management Discussion and Analysis of Financial and Operational Performance for the six months ended 31 December 2012

21 February 2013

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 2012 compared with the six months ended 31 December 2011 (“prior corresponding period”) except where otherwise stated.

As required by the International Financial Reporting Standards’ (IFRS) accounting standards, Infigen consolidates 100% of all controlled entities within its result. 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 reference 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 Energy that any projection, forecast, forward-looking statement, assumption or estimate contained in this presentation should or will be achieved.

1 Statutory Result

1.1 Statutory Loss

Infigen Energy reported a Statutory Loss for the six months to 31 December 2012 of $27.8 million, a favourable movement of $7.4 million compared with a Statutory Loss of $35.2 million in the prior corresponding period (pcp).

Further details are provided in Section 2.

1.2 Dividends

Following consideration by the Board in late 2012 and as advised by the Chairman of the Board at the 2012 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) improved from 1.1 at 31 December 2011 to zero at 31 December 2012. Achieving this important milestone is pleasing and we will continue to strive to maintain this safety record.

Regrettably in early 2013 we had two lost time incidents. They served as an immediate 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 Dec ($m unless otherwise indicated)	2012	2011	Change % F/(A)
Revenue	140.9	133.5	6
EBITDA	74.9	67.9	10
Depreciation and amortisation	(68.8)	(69.8)	1
EBIT	6.1	(1.9)	421
Net borrowing costs	(41.3)	(37.1)	(11)
FX and interest rate derivative revaluation	(6.2)	0.9	(789)
Net Income from IEPs	11.2	(1.4)	900
Loss before significant item & tax	(30.3)	(39.5)	23
Income tax benefit	2.5	4.2	(40)
Net loss after tax	(27.8)	(35.2)	21
Operating cash flow	25.5	25.9	(1)
Capital expenditure[1]	7.6	23.2	(67)
Operating cash flow per security[2] (cps)	3.3	3.4	(3)
Earnings per security (cps) [3]	(3.6)	(4.6)	21

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 ($m unless otherwise indicated)	31 Dec 2012	30 June 2012	Change % F/(A)
Debt	1,039	1,069	3
Cash	110	127	(13)
Net debt	929	943	1
Class A liability	605	632	4
Securityholders' equity	499	526	(5)
Book Gearing	65.0%	64.2%	(0.8) ppts[4]
EBITDA/(Net debt + Equity)	11.2%	10.4%	0.8 ppts
Net assets per security ($)	0.66	0.69	(4)
Net tangible assets per security ($)	0.25	0.27	(7)

n.m. = not meaningful
[1] Represents the cash outflow in relation to capital expenditure
[2] Calculated using securities issued at end of year
[3] Calculated using weighted average issued securities
[4] 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 Class B interests[5]. 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 recorded through "Net Income of IEPs".

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

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

Six months ended 31 Dec 2012 ($ million)	Statutory	Non-controlling Interest	Economic Interest
Revenue	140.9	(6.7)	134.2
Operating EBITDA	83.6	(4.0)	79.6
Other costs and income	(8.7)	-	(8.7)
EBITDA	74.9	(4.0)	70.9
Depreciation and amortisation	(68.8)	3.8	(65.0)
EBIT	6.1	(0.1)	6.0
Net borrowing costs	(41.3)	0.2	(41.1)
FX and interest rate derivative revaluation	(6.2)	-	(6.2)
Net income from IEPs	11.2	(0.1)	11.1
Loss before tax	(30.3)	-	(30.3)
Income tax benefit	2.5	-	2.5
Net loss	(27.8)	-	(27.8)

Six months ended 31 Dec 2011 ($ million)	Statutory	Non-controlling Interest	Economic Interest
Revenue	133.5	(7.8)	125.7
Operating EBITDA	75.8	(5.7)	70.1
Other costs and income	(7.9)	-	(7.9)
EBITDA	67.9	(5.7)	62.2
Depreciation and Amortisation	(69.8)	3.8	(66.0)
EBIT	(1.9)	(1.9)	(3.8)
Net Borrowing Costs	(37.1)	-	(37.1)
FX and interest rate derivative revaluation	0.9	-	0.9
Net income from IEPs	(1.4)	1.9	0.5
Loss before tax	(39.5)	-	(39.5)
Income tax	4.2	-	4.2
Net loss	(35.2)	-	(35.2)

[5] Infigen also has a number of joint ventures where its Class B membership interests range from 53% to 59% (joint control). These membership interests are included in both statutory and economic presentations using the same proportional ownership method of consolidation.

2.2 Management discussion of income statement

Six months ended 31 Dec ($m unless otherwise indicated)	2012	2011	Change % F/(A)
Revenue	134.2	125.7	7
Operating EBITDA	79.6	70.1	14
Other costs and income	(8.7)	(7.9)	(10)
EBITDA	70.9	62.2	14
Depreciation and amortisation	(65.0)	(66.0)	1
EBIT	6.0	(3.8)	258
Net borrowing costs	(41.1)	(37.1)	(11)
FX and interest rate derivative revaluation	(6.2)	0.9	(789)
Net Income from IEPs	11.1	0.5	2,120
Loss before significant item & tax	(30.3)	(39.5)	23
Income tax	2.5	4.2	(40)
Net loss after tax	(27.8)	(35.2)	21
Operating cash flow	23.0	21.1	9
Capital expenditure[6]	7.6	23.2	(67)
Operating cash flow per security[7] (cps)	3.0	2.8	9
Earnings per security (cps) [8]	(3.6)	(4.6)	21

Foreign exchange rates			
Average rate for the six months ended	**31 Dec 2012**	**31 Dec 2011**	**Change %**
AUD:USD	1.0355	1.0112	2
AUD:EUR	0.8113	0.7421	9

Revenue was $134.2 million, up 7% or $8.5 million reflecting higher production and merchant electricity prices in Australia and higher compensated revenue following the resolution of an Australian Electricity Market Operator (AEMO) scheduling error, partially offset by lower production in the US, lower merchant electricity prices in the US, lower LGC prices in Australia and adverse FX movement.

Operating Earnings before Interest, Tax, Depreciation and Amortisation (**Operating EBITDA**) was $79.6 million, up 14% or $9.5 million. This was primarily due to:

- Australia: higher revenue described above and marginally higher operating costs primarily related to a full period of costs for Woodlawn wind farm compared to pcp and production and revenue linked land lease costs; and
- US: marginally lower revenues described above partially offset by lower turbine operating and maintenance (O&M) costs.

Development costs expensed were $1.8 million, down $0.1 million primarily reflecting a reduction in costs in the Australian business (-$0.5 million) offset by new costs associated with US development activity (+$0.4 million).

Corporate costs were $7.6 million, up 33% or $1.9 million. This was primarily due to the write back of non-cash incentive provisions in the pcp.

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

Other income contributed $0.8 million and relates to an insurance recovery in relation to the replacement of a wind turbine generator in the US during the period.

Depreciation and Amortisation expense was $65.0 million, down $1.0 million due to the appreciation of the AUD against the USD. The expense for the period in the US and Australia was US$41.5 million and $24.9 million respectively.

Net Borrowing Costs were $41.1 million, up 10% or $4.0 million reflecting higher amortisation of loan fees and decommissioning provision related costs partially offset by a lower interest expense due to lower outstanding debt.

Six months ended 31 Dec	2012 ($m)	2011 ($m)	Change % F/(A)
Interest Expense	(36.8)	(37.5)	2
Loan and Bank Fees	(3.1)	(1.0)	(210)
Amortisation of Decommissioning Cost	(2.5)	-	n.m.
Total Borrowing costs	**(42.4)**	**(38.6)**	**(10)**
Interest Income	1.3	1.5	(13)
Net Borrowing Costs	**(41.1)**	**(37.1)**	**(10)**
FX (Loss) / Gain	(5.4)	5.3	(202)
Interest rate derivative revaluation	(0.8)	(4.3)	81

Net foreign exchange loss of $5.4 million primarily arose on the close out of foreign exchange contracts taken out to hedge Euro denominated debt repayments and where the offsetting benefit was realised through higher Euro cross rates being maintained over the repayment period. This compares with a $5.3 million gain in the pcp following a further appreciation of the AUD against the USD. The $0.8 million costs associated with the **interest rate derivative revaluation** reflects further decreases in benchmark interest rates.

Net income from US IEPs was $11.1 million, up $10.6 million compared with an expense of $0.5 million in the pcp. An explanation of the structure of IEPs (including the accounting treatment) is provided in Appendix B of the Management Discussion and Analysis for the year ended 30 June 2012.

Income Tax benefit of $2.5 million was $1.7 million lower than the pcp. The tax benefit this year was primarily attributable to the lower accounting loss of the Australian business compared to the pcp.

Statutory Loss for the six months was $27.8 million, a favourable movement of $7.4 million compared with a Statutory Loss of $35.2 million in the pcp.

3 Cash Flow

3.1 Cash movement

Cash balance at 31 December 2012 was $110 million, 13% or $16 million lower than the $126 million cash balance at 30 June 2012. The cash balance at 31 December 2012 comprises $18 million held by entities within the Global Facility Borrower Group (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') with $92 million held by entities outside of that group ('Excluded Companies').

Cash outflows comprised $27.2 million for debt repayment ($26.1 million towards the Global Facility and $1.1 million towards the Woodlawn project finance facility), $4.7 million in distributions to Class A tax equity holders and $7.6 million in capital expenditure primarily related to the turbine replacement at Allegheny Ridge and other US expenditure ($4.8 million), development activities in the US ($1.1 million) and Australia ($1.1 million) and IT projects ($0.6 million).

Cash inflow for the period comprised $23 million of net operating cash flow and $0.3 million due to FX movements.

3.2 Operating Cash Flow

Net operating cash flow after tax and financing costs

Six months ended 31 Dec	2012 ($m)	2011 ($m)	Change % F/(A)
Operating EBITDA	79.6	70.1	14
Corporate & development costs & other	(8.7)	(7.6)	(14)
Working capital & non-cash items	(10.0)	(0.7)	(1,329)
Net financing costs and taxes paid	(37.9)	(40.7)	7
Net Operating Cash Flow	***23.0***	***21.1***	***9***
Distributions[9] paid (Class A)	*(4.7)*	*(2.0)*	*135*
Non-controlling interests			
Distributions paid (Class A and Class B)	*7.2*	*7.6*	*(5)*
Movement in working capital	-	*(0.8)*	*n.m.*
Operating Cash Flow (Statutory)	***25.5***	***25.9***	***(2)***

Net operating cash flow after tax and financing costs was $23.0 million for the six months, up 9% or $1.9 million. Higher operating EBITDA (refer Section 2) and lower net financing costs and taxes paid was partially offset by higher working capital and non-cash items. The working capital outflow ($10.6 million) is largely attributable to timing differences with a quarterly prepayment under the Mitsubishi extended warranty agreement (not on hand in the pcp) and an increase in receivables accumulated under a take-or-pay contract (for which the cash was received subsequent to balance date).

[9] Distributions paid to institutional equity partners are classified as financing cash flows reflecting their treatment as debt-like instruments

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') and a project finance facility for which recourse is limited to Woodlawn.

Total debt at 31 December 2012 was $1,038.9 million (including capitalised loan costs) comprising $987.6 million of Global Facility debt and $51.3 million of Woodlawn project finance debt. This was a reduction of $30.3 million compared with $1,069.2 million at 30 June 2012. During the six months to 31 December 2012 the Borrower Group applied $26.1 million to repayment of the Global Facility. A further $1.1 million was applied to repayment of the Woodlawn project finance facility and the appreciation of the AUD against the USD resulted in $3.1 million in favourable FX movements.

The Global Facility leverage ratio covenant was met at 31 December 2012.

4.2 Net Debt

The Net debt for the consolidated entity (economic interest) decreased from $943 million at 30 June 2012 to $929 million at 31 December 2012. The factors contributing to the net $14 million movement are as follows:

- net operating cash flow (+$23.0 million),
- unrealised FX benefit (+$3.3 million),
- capital expenditure (-$7.6 million), and
- distributions to Class A tax equity members (-$4.7 million).

4.3 Equity

Total equity decreased 5% from $526 million at 30 June 2012 to $499 million at 31 December 2012. The decrease of $27 million is primarily attributable to the net loss for the period (-$28 million) and to a lesser extent the changes in fair value of cash flow hedges (-$3 million) partially offset by exchange differences on translation of foreign operations and movement in fair value (+$3 million) and recognition of share-based payments (+$1 million).

5 Operational Performance Review

5.1 US

Financial performance

Six months ended 31 Dec	2012	2011	Change F/(A)	Change % F/(A)
Total Revenue (US$M)	59.9	62.5	(2.6)	(4)
Operating EBITDA (US$M)	22.7	24.1	(1.5)	(6)
Production Tax Credits (US$M)	32.9	35.3	(2.4)	(7)
US Wind Farms				
Wind Farm Revenue (US$M)	58.1	60.8	(2.7)	(4)
Wind Farm EBITDA (US$M)	22.1	24.0	(1.9)	(8)
EBITDA Margin	38.0%	39.5%		(1.5) ppt
Average Price ($/MWh)	42.97	44.44	(1.47)	(3)
Wind Farm cost ($/MWh)	26.55	26.90	0.35	1
EBITDA margin inc PTCs	*60.4%*	*63.2%*		*(2.8) ppt*
Management Services				
Revenue (US$M)	1.8	1.6	0.2	13
EBITDA (US$M)	0.5	0.1	0.4	400
Translation to AUD				
Revenue (A$M)	57.8	61.8	(4.0)	(6)
Operating EBITDA (A$M)	21.8	23.8	(2.0)	(8)

Operational performance

Six months ended 31 Dec	2012	2011	Change F/(A)
Operating Capacity (MW)	1,089	1,089	-
Capacity Factor	28.1%	28.3%	(0.2) ppt
Turbine Availability	96.0%	95.9%	0.1 ppt
Site Availability	94.6%	94.9%	(0.3) ppt
Production (GWh)	1,352	1,368	(1)

5.1.1 Production

Production decreased 1% or 16 GWh to 1,352 GWh with mixed wind conditions across the wind farms. The variance primarily reflects a planned gearbox change out program at Cedar Creek covered under the MHI extended warranty agreements (-17 GWh), large-scale substation maintenance at the Allegheny Ridge and Kumeyaay wind farms (-9 GWh), economic curtailments at the Mendota and Crescent Ridge wind farms (-9 GWh), a nacelle fire and blade related issues at Allegheny Ridge wind farm (-4 GWh) and proactive avian-related environmental curtailments (-3 GWh). These decreases were partially offset by improved production at Aragonne Mesa (+18 GWh), which was offline for a time during the pcp due to an electrical equipment upgrade project, and improved wind conditions at Caprock (+6 GWh).

Turbine availability improved 0.2% to 96.1%, however site availability decreased 0.3% to 94.6% due to scheduled substation maintenance.

5.1.2 Price

The average portfolio price realised decreased 3% to US$42.97MWh compared to US$44.44/MWh. This was due to lower realised electricity prices from merchant wind farms in the Texas (ERCOT) market.

The time weighted average PJM and ERCOT prices for the six months are outlined below. Lower ERCOT electricity prices resulted from lower price volatility during the period compared to the pcp.

Period (US$/MWh)	H1 FY13	H1 FY12	Change % F/(A)
PJM	29.96	28.51	5
ERCOT	23.60	43.34	(46)

5.1.3 Wind Farm Revenue

Revenue decreased 4% or US$2.7 million to US$58.1 million. This primarily reflected a net decrease in production due to the factors described earlier (-US$0.9 million), lower merchant electricity prices (-US$1.4 million), lower compensated revenue (-US$1.0 million) and higher average prices at the contracted wind farms (US$0.6 million).

5.1.4 Wind Farm Costs

Wind farm costs decreased 2% or US$0.9 million to US$35.9 million reflecting improved operating and maintenance practices.

- Asset Management costs increased US$0.4 million to US$5.8 million primarily reflecting higher professional fees.
- Turbine O&M costs decreased $2.0 million primarily due to lower service and maintenance costs at the GSG wind farm (-US$0.7 million) following contractors being transitioned in-house and lower component failures and unscheduled maintenance costs partially offset by higher fixed costs associated with the Mitsubishi extended warranty agreements entered into in 2012 (-US$1.3 million).
- Balance of plant costs increased US$0.4 million due to equipment repairs (+US$0.2 million), substation maintenance and testing (+US$0.1 million) and a contractual step up in balance of plant service and maintenance (+US$0.1 million).
- Other direct costs increased US$0.3 million reflecting increased insurance and property tax expenses.

Six months ended 31 Dec (US$M)	2012	2011	Change F/(A)	Change % F/(A)
Asset Management	5.8	5.4	(0.4)	(7)
Turbine O&M	17.0	19.0	2.0	10
Balance of Plant	3.6	3.2	(0.4)	(12)
Other Direct Costs	9.5	9.2	(0.3)	(3)
Wind Farm Costs	**35.9**	**36.8**	**0.9**	**2**
Wind farm costs US$/MWh	*26.55*	*26.90*	*0.35*	*1*

Wind farm costs on an actual per megawatt-hour production basis decreased 1% or US$0.35/MWh to US$26.55/MWh reflecting lower wind farm costs described above.

5.1.5 Infigen Asset Management Revenue and Costs

Six months ended 31 Dec (US$M)	2012	2011	Change F/(A)	Change % F/(A)
Revenue	1.8	1.6	0.2	13
Operating Costs	1.3	1.5	0.2	13
EBITDA	**0.5**	**0.1**	**0.4**	**400**

Revenue from Infigen Asset Management operations was US$1.8 million compared to US$1.6 million in the pcp. The US$0.2 million increase reflects higher asset management fees.

Operating costs associated with the Infigen Asset Management business decreased US$0.2 million to US$1.3 million. The pcp contained one off costs for some sites transitioning off warranty.

5.1.6 Operating EBITDA

Operating EBITDA for the entire US business decreased 6% or US$1.5 million to US$22.7 million primarily reflecting lower wind farm revenue partially offset by marginally higher IAM revenue and lower operating costs across the business.

Operating EBITDA from the US wind farms of US$22.1 million was 8% or US$1.9 million lower than the pcp reflecting lower revenue and partially offset by lower wind farm costs.

EBITDA Margins Six months ended 31 Dec	2012	2011	Change ppts F/(A)
Wind Farm	38.0%	39.5%	(1.5)
Wind Farm & PTC	60.4%	63.2%	(2.8)

EBITDA margin from the wind farms was 38.0% compared with 39.5% in the pcp. This primarily reflected lower revenue offset to some extent by lower unit turbine O&M costs.

EBITDA margins including PTCs also reduced to 60.4% for the reasons described above.

5.1.7 Development

Work continued on the solar development pipeline and during the period Infigen expanded its solar development portfolio through the development of greenfield sites in California, New Mexico, New York and Georgia.

5.2 Australia

Financial performance

Six months ended 31 Dec ($M) unless stated otherwise	2012	2011	Change F/(A)	Change % F/(A)
Revenue	76.4	63.9	12.5	20
Operating EBITDA	57.8	46.2	11.6	25
Operating EBITDA margin (%)	75.6	72.3		3.3 ppts
Average Price (A$/MWh)	94.36	89.25	5.1	6
Operating Cost (A$/MWh)	22.96	24.72	1.7	7

Operational performance

Six months ended 31 Dec	2012	2011	Change F/(A)
Operating Capacity (MW)	557	557	-
Capacity Factor	32.9%	29.5%	3.4 ppt
Turbine Availability	97.5%	96.8%	0.7 ppt
Site Availability	96.6%	95.9%	0.7 ppt
Production (GWh)	810	716	13

5.2.1 Production

Production increased 13% or 94 GWh to 810 GWh reflecting better wind conditions (+48 GWh), higher compensated production following the resolution of an AEMO scheduling error (+27 GWh) and a full six months contribution from the Woodlawn wind farm (+22 GWh) offset by higher balance of plant and economic curtailment related losses (-2 GWh).

Turbine and site availability both improved by 0.7%.

Network constraints are limitations of the transmission network which can reduce Infigen's production for which Infigen receives no compensation. Network constraints were similar to the pcp with an improvement in the network availability affecting Lake Bonney wind farm (+12 GWh) offsetting higher losses at Alinta wind farm (-12 GWh).

The region around Capital wind farm has experienced historical low wind speeds since the wind farm's completion. Infigen's recent outlook has been based on an expectation of the annual energy output from Capital being below its original long-term forecast. Preliminary results of an updated wind and energy assessment currently being undertaken for Capital indicate that it would be prudent to adopt a reduced capacity factor of approximately 30% for the foreseeable future.

While Woodlawn wind farm is located adjacent to Capital wind farm it has outperformed Capital in terms of capacity factor and its performance to date, allowing for below average wind speed, is in line with long term expectations.

5.2.2 Prices

In SA and NSW time weighted average electricity prices were 83% and 88% higher than the pcp respectively. This reflected the introduction of the carbon price from 1 July 2012 and some coal supply issues in Victoria. Excluding the estimated carbon price effect, electricity prices during the period were around the ten year average prices (to 31 December 2012) in SA and NSW.

The average monthly LGC price for the six months was down 9% to $36.66 compared with $40.40 in the pcp. This appears to be primarily due to increased regulatory uncertainty during the RET review undertaken by the Climate Change Authority. The LGC price at 31 December 2012 was also down 9% to $37.20 compared with $41.05 at 31 December 2011.

As a result of improved electricity prices, Infigen's weighted average portfolio bundled (electricity and LGCs) price was 6% higher at $94.36/MWh compared to $89.25/MWh in the pcp. Infigen's Australian assets are currently 55% contracted on a P50 basis.

Time weighted average price ($/MWh)	H1 FY13	H1 FY12	10 Year Average
SA - Electricity	61.1	33.4	39.6
NSW – Electricity	56.7	30.1	40.2

5.2.3 Revenue

Revenue increased 20% or $12.5 million to $76.4 million. This reflected an uplift in electricity prices following the introduction of the carbon price (+$8.1 million), improved production due to better wind conditions, including a full six months contribution from Woodlawn (+$4.7 million), and compensated revenue from AEMO following the resolution of a scheduling error (+$1.2 million). This was partially offset by lower revenue from the sale of LGCs at prices lower than the pcp (-$1.5 million).

At 31 December 2012 Infigen held approximately 312,000 LGCs with a book value of $11.4 million. The average book value was $36.60 per LGC compared with a closing market price of $37.20 per LGC at 31 December 2012. Reported revenue included $1.3 million related to LGCs that were created but not sold during the period.

5.2.4 Operating Costs

Total operating costs increased 5% or $0.9 million primarily reflecting full period costs associated with the Woodlawn wind farm, which commenced commercial operation in the middle of the pcp, higher balance of plant maintenance costs and higher costs associated with production and revenue linked land lease payments.

Wind farm costs increased 7% or $1.1 million to $16.3 million reflecting:

- full period asset management costs for the Woodlawn wind farm and professional fees related to the AEMO compensation claim (+$0.4 million);
- full period turbine O&M costs at Woodlawn wind farm (+$0.3 million) and higher turbine O&M costs associated with the Vestas post-warranty service and maintenance agreements offset by lower component replacement costs associated with turbines covered by the Vestas agreements (-$0.4 million);
- balance of plant equipment repairs and maintenance costs (+$0.3 million); and
- an increase in production and revenue linked land leases payments (+$0.4 million) and inflation escalated connection costs (+$0.1 million).

Six months ended 31 Dec ($M)	2012	2011	Change F/(A)	Change % F/(A)
Asset Management	3.5	3.1	(0.4)	(13)
Turbine O&M	8.7	8.8	0.1	1
Balance of Plant	0.4	0.1	(0.3)	(300)
Other Direct Costs	3.7	3.2	(0.5)	(16)
Wind Farm Costs	**16.3**	**15.2**	**(1.1)**	**(7)**
Wind farm costs $/MWh	*20.13*	*21.20*	*1.07*	*5*
Energy Markets	2.3	2.5	0.2	8
Operating Costs	**18.6**	**17.7**	**(0.9)**	**(5)**
Total operating costs $/MWh	*22.96*	*24.72*	*1.76*	*7*

Wind farm costs on an actual per megawatt-hour production basis decreased 5% or $1.07/MWh to $20.13/MWh. This primarily reflects higher production during the period as a result of improved wind conditions, compensated production and improved availability.

Energy Markets costs decreased $0.2 million reflecting lower hedging costs compared to the pcp.

5.2.5 Operating EBITDA

Operating EBITDA increased 25% or $11.6 million to $57.8 million reflecting higher revenue from higher production and higher merchant electricity prices partially offset by lower LGC prices and slightly higher operating costs.

Operating EBITDA margin for the period was 75.6% compared with 72.3%. The higher margin primarily reflects higher revenue due to factors described above.

5.2.6 Development

During the period Infigen committed to construction of the 120 kW (stage 1) Capital East Solar Demonstration Plant, a solar photovoltaic and energy storage facility. It is expected to be commissioned in 2013.

The Forsayth wind farm development in Queensland secured development consent during the period and the Flyers Creek, Bodangora and Cherry Tree wind farms completed their public exhibitions.

Discussions with the Australian Renewable Energy Agency (ARENA) regarding potential funding for the Capital solar farm continue.

6 Outlook

Consistent with long-term seasonal variation, second half production is expected to increase in the US and to decrease in Australia. In the US, weak wind conditions in the first half continued into January 2013 with the full year outcome unlikely to reach the outcome in the pcp. In Australia, the higher production achieved over the pcp in the first half is for the most part expected to be carried through to the full year outcome.

In the US, continued depressed merchant electricity prices in the PJM and ERCOT markets are expected for the remainder of FY13. In Australia, SA and NSW electricity cap prices for the second half of FY13 indicate low pool price volatility expectations, notwithstanding more extreme weather conditions and higher demand experienced in early 2013. LGC prices are expected to remain relatively steady for the remainder of the financial year.

We expect that full year wind farm costs in the US and Australia will be at the lower end of the US$74-79 million and A$34-37 million guidance ranges respectively.

Subject to these operating conditions, Infigen remains on track to repay around $55 million of Global Facility borrowings in FY13 and expects to continue to meet the Global Facility leverage ratio covenant test for the 2013 financial year.

Infigen has implemented a cost review and organisational restructure to improve efficiency and reduce our operating costs in Australia and the US. Our target is to reduce costs by $7 million per annum from FY14. This represents approximately 15% of the addressable cost base noting that a significant part of our operational costs are now largely fixed due to warranty or extended post warranty service and maintenance agreements. The impact on the FY13 result is anticipated to be neutral with savings offset by associated restructure costs.

7 Appendix A – Balance Sheet by Country

A$ million	31 Dec 12 IFN Statutory Interest	Less US Minority Interest	31 Dec 12 IFN Economic Interest	Australia	United States
Cash	110.4	(0.4)	110.0	101.0	9.0
Receivables	42.3	(1.7)	40.6	26.7	13.9
Inventory & LGCs	17.0	(0.2)	16.9	13.0	3.8
Prepayments	20.1	(0.7)	19.4	10.5	8.8
PPE	2,354.2	(145.8)	2,208.4	936.9	1,271.5
Goodwill & intangibles	312.6	(15.8)	296.7	137.5	159.3
Deferred tax & other assets	52.3	(0.0)	52.3	52.3	0.0
Total assets	**2,909.0**	**(164.7)**	**2,744.3**	**1,278.0**	**1,466.3**
Payables	47.6	(3.3)	44.3	15.6	28.7
Provisions	11.0	(0.5)	10.4	5.5	4.9
Borrowings	1,038.9	(0.0)	1,038.9	716.0	322.9
Tax Equity (US)	654.6	(113.3)	541.3	0.0	541.3
Deferred revenue (US)	468.6	(47.5)	421.0	(0.0)	421.0
Interest rate derivative	189.0	(0.0)	189.0	129.8	59.3
Total Liabilities	**2,409.6**	**(164.7)**	**2,244.9**	**866.9**	**1,378.1**
Net assets	**499.3**	**(0.0)**	**499.3**	**411.1**	**88.2**

Foreign exchange rates			
As at	**31 Dec 2012**	**31 Dec 2011**	**Change %**
USD	1.0378	1.0233	1
EUR	0.7868	0.7895	(-)

8 Appendix B – Institutional Equity Partnerships

8.1 Six months ended 31 December 2012

Production (GWh) by Asset Vintage

Six months ended 31 Dec	2012	2011	Change F/(A)	Change % F/(A)
2003/2004	340	329	11	3
2005	209	219	(10)	(5)
2006	342	342	-	-
2007	461	478	(17)	(4)
Total	**1,352**	**1,368**	**(16)**	**(1)**

Revenue (US$ million) by Asset Vintage

Six months ended 31 Dec	2012	2011	Change F/(A)	Change % F/(A)
2003/2004	9.9	9.4	(0.5)	(5)
2005	9.6	10.4	(0.8)	(8)
2006	17.3	18.1	(0.8)	(4)
2007	21.3	23.0	(1.7)	(7)
Total	**58.1**	**60.8**	**(0.4)**	**(4)**

Profit and Loss (US$ million) by Asset Vintage

Six months ended 31 Dec 2012	2003/04	2005	2006	2007	Total
Revenue	9.9	9.6	17.3	21.3	58.1
Costs	(5.7)	(6.0)	(13.5)	(10.7)	(35.9)
EBITDA	4.2	3.5	3.8	10.6	22.1
D&A	(6.3)	(6.6)	(12.7)	(15.7)	(41.3)
EBIT	**(2.2)**	**(3.0)**	**(8.9)**	**(5.0)**	**(19.1)**

Class A Capital Balance Amortisation (US$ million) by Asset Vintage

Six months ended 31 Dec 2012	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	(7.9)	(5.4)	(9.1)	(10.5)	(32.9)
Tax (losses)/ gains	2.3	1.2	0.3	(3.0)	0.8
Cash distributions	(3.1)	(1.9)	-	-	(5.0)
Allocation of return (interest)	2.7	3.6	4.8	7.4	18.5
Closing Balance	**59.7**	**92.9**	**157.8**	**231.8**	**542.2**

8.2 Year ended 30 June 2012

Production (GWh) by Asset Vintage

Year ended 30 June	2012	2011	Change F/(A)	Change % F/(A)
2003/2004	716	760	(44)	(6)
2005	519	574	(55)	(10)
2006	820	859	(39)	(4)
2007	1,081	1,139	(58)	(5)
Total	**3,136**	**3,332**	**(197)**	**(6)**

Revenue (US$ million) by Asset Vintage

Year ended 30 June	2012	2011	Change F/(A)	Change % F/(A)
2003/2004	21.6	21.1	0.5	2
2005	24.9	27.1	(2.3)	(8)
2006	43.7	45.9	(2.2)	(5)
2007	50.3	51.2	(0.9)	(2)
Total	**140.5**	**145.3**	**(0.4)**	**(3)**

Profit and Loss (US$ million) by Asset Vintage

Year ended 30 June 2012	2003/04	2005	2006	2007	Total
Revenue	21.6	24.9	43.7	50.3	140.5
Costs	(12.3)	(13.3)	(30.0)	(17.7)	(73.3)
EBITDA	9.3	11.6	13.7	32.6	67.2
D&A	(11.8)	(12.5)	(25.9)	(30.1)	(80.3)
EBIT	**(2.5)**	***(0.9)***	***(12.2)***	***2.5***	***(13.1)***

Class A Capital Balance Amortisation (US$ million) by Asset Vintage

Year ended 30 June 2012	2003/04	2005	2006	2007	Total
Closing Balance (30 Jun 11)	83.0	103.3	170.8	253.3	610.4
Tax true-up	(0.1)	(0.2)	-	-	(0.3)
Opening Balance (1 Jul 11)	**82.9**	**103.1**	**170.8**	**253.3**	**610.1**
Production Tax Credits	(16.4)	(12.2)	(18.6)	(25.4)	(72.6)
Tax (losses)/ gains	2.7	1.4	0.0	(4.0)	0.1
Cash distributions	(9.5)	(4.6)	0.0	0.0	(14.1)
Allocation of return (interest)	6.1	7.4	9.8	14.7	38.0
Closing Balance	**65.8**	**95.1**	**162.0**	**238.6**	**561.5**

8.3 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 2012 for more detail).

Cash flow allocated to Class A members during the period was US$5.0 million compared with US$1.9 million in the pcp. This relates to the Blue Canyon, Combine Hills, Caprock, Crescent Ridge, Jersey Atlantic, Bear Creek and Sweetwater 1-3 wind farms, where from the second half of FY13 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)				
Six months ended 31 Dec	**2012**	**2011**	**Change F/(A)**	**Change % F/(A)**
2003/2004	59.7	75.4	15.7	21
2005	92.9	102.0	9.1	9
2006	157.8	166.9	9.1	5
2007	231.8	245.7	13.9	6
Total	**542.2**	**589.9**	**47.7**	**8**

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

Economic Interest Class B Capital Balance by vintage (US$ million)				
Six months ended 31 Dec	**2012**	**2011**	**Change F/(A)**	**Change % F/(A)**
2003/2004	0.5	1.8	1.3	72
2005	6.2	12.3	6.1	50
2006	111.0	129.4	18.4	14
2007	64.0	97.1	33.1	34
Total	**181.7**	**240.6**	**58.9**	**24**

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 2012 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. Jersey Atlantic, Bear Creek and Sweetwater 1-3 wind farms reached their cash flip point during the current six month period.

All of the wind farms in the 2005 vintage portfolio except Kumeyaay are distributing cash to the Class A members. Kumeyaay will begin to distribute cash to the Class A members before the end of FY13.

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 is expected to reach its cash flip point in approximately 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 November 2014. Cedar Creek accounted for 60% of the distributions from the 2007 vintage portfolio in FY12.

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 no later than December 2016 with the Crescent Ridge and Caprock wind farms expected to follow in June 2017 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 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 in USD.

Six months ended 31 Dec	2012 (US$m)	2011 (US$m)	Change % F/(A)
Value of production tax credits (Class A)	36.1	39.0	(7)
Value of tax losses (Class A)	0.5	2.0	(75)
Benefits deferred during the period	(2.3)	(14.1)	84
Income from IEPs	**34.3**	**26.9**	**28**
Allocation of return (Class A)	(20.6)	(22.1)	7
Movement in residual interest (Class A)	(2.2)	(2.6)	15
Non-controlling interest (Class B)	-	(3.6)	(100)
Financing costs related to IEPs	**(22.8)**	**(28.3)**	**(19)**
Net income from IEPs (Statutory)	**11.5**	**(1.4)**	**n.m.**
Non-controlling interests (Class B & Class A)	(0.1)	1.9	(105)
Net income from IEPs (Economic Interest)	**11.4**	**0.5**	**2,180**

The following table summarises the components of net income from IEPs in AUD.

Six months ended 31 Dec	2012 (A$m)	2011 (A$m)	Change % F/(A)
Value of production tax credits (Class A)	34.9	38.6	(10)
Value of tax losses (Class A)	0.5	2.0	(75)
Benefits deferred during the period	(2.1)	(13.9)	85
Income from IEPs	**33.3**	**26.7**	**25**
Allocation of return (Class A)	(19.9)	(21.9)	6
Movement in residual interest (Class A)	(2.2)	(2.6)	15
Non-controlling interest (Class B)	-	(3.6)	(100)
Financing costs related to IEPs	**(22.1)**	**(28.1)**	**21**
Net income from IEPs (Statutory)	**11.2**	**(1.4)**	**n.m.**
Non-controlling interests (Class B & Class A)	(0.1)	1.9	(105)
Net income from IEPs (Economic Interest)	**11.1**	**0.5**	**2,120**

Value of Production Tax Credits (PTCs) (Class A) was $34.9 million, down 10% or $3.7 million largely reflecting lower production and the depreciation of the AUD against the USD. The unit value of a PTC was US$22 for both the 2011 and 2012 calendar years.

Value of tax losses (Class A) was $0.5 million, down 75% or $1.5 million due to the reduction in tax depreciation as the remaining assets that benefit from accelerated depreciation become fully depreciated.

During the period $2.1 million of benefits were deferred, down 85% or $11.8 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 $19.9 million expense for the period, down 6% or $2.0 million reflecting both lower Class A capital balances and the appreciation of the AUD against the USD.

The movement in residual interest (Class A) was $2.6 million, down $0.4 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).