On 25 November 2009 the Australian Competition Tribunal (Tribunal) made orders varying the Australian Energy Regulator's (AER) *New South Wales distribution determination 2009–10 to 2013–14* by:

- determining the weighted average cost of capital (WACC) to be based on an August–September 2009 averaging period for the 10-year bond rates. This results in increasing the nominal vanilla WACC for the NSW distribution network service providers (NSW DNSPs)—Country Energy, EnergyAustralia and Integral Energy—to 10.02 per cent from around 8.80 per cent
- increasing the controllable operating expenditure allowance for EnergyAustralia by $4.5 million to $2582 million ($2008–09)
- amending the definition of the general nominated pass through event for EnergyAustralia
- remitting the AER's decision in respect of EnergyAustralia's alternative control (public lighting) services to the AER for re–determination by 15 April 2010, taking account of information to be submitted by EnergyAustralia and interested parties.

The adjusted WACC (and operating expenditure allowance for EnergyAustralia) will increase the expected revenues of the NSW DNSPs for providing standard control services during the 2009–10 to 2013–14 regulatory control period. In accordance with the Tribunal's decision, the AER has set out below updated calculations of the expected revenues for the NSW DNSPs (including other relevant calculations, such as the operating expenditure allowance for EnergyAustralia) in the AER's final decision on the NSW distribution determination dated 28 April 2009 (2009 final decision). The adjusted WACC also has the effect of increasing the charges for public lighting services for the NSW DNSPs. This update will be made as part of the AER's re–determination of EnergyAustralia's public lighting services and the alternative control services annual price determination for Country Energy and Integral Energy.

Tables 1, 2 and 3 set out the updated WACC for the next regulatory control period and replace tables 11.3, 11.7 and 11.9 (and table 17) respectively of the AER's 2009 final decision.

Table 1: AER conclusion on the nominal risk–free rate for the NSW DNSPs (per cent)

NSW DNSP	Averaging Period determined by the Tribunal	Nominal risk–free rate (effective annual compounding rate)
Country Energy	15 business days, 18 August 2008 to 5 September 2008	5.82
EnergyAustralia	15 business days, 18 August 2008 to 5 September 2008	5.82
Integral Energy	15 business days, 18 August 2008 to 5 September 2008	5.82

Table 2: AER conclusion on the debt risk premium for the NSW DNSPs (per cent)

NSW DNSP	Averaging period determined by the Tribunal	Debt risk premium	Risk–free rate	Nominal return on debt
Country Energy	18 August 2008 to 5 September 2008	3.00	5.82	8.82
EnergyAustralia	18 August 2008 to 5 September 2008	3.00	5.82	8.82
Integral Energy	18 August 2008 to 5 September 2008	3.00	5.82	8.82

Table 3: AER conclusion on the WACC parameters for the NSW DNSPs

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	5.82%	5.82%	5.82%
Risk–free rate (real)[a]	3.27%	3.27%	3.27%
Expected inflation rate	2.47%	2.47%	2.47%
Debt risk premium	3.00%	3.00%	3.00%
Market risk premium	6.00%	6.00%	6.00%
Gearing	60%	60%	60%
Equity beta	1.00	1.00	1.00
Nominal pre–tax return on debt	8.82%	8.82%	8.82%
Nominal post–tax return on equity	11.82%	11.82%	11.82%
Nominal vanilla WACC	10.02%	10.02%	10.02%

(a) The real risk–free rate was calculated using the Fisher equation.

Table 4 sets out the updated allowances for benchmark equity raising costs associated with forecast capital expenditures for the next regulatory control period and replaces table 8.18 of the AER's 2009 final decision. The allowances have changed because the calculations depend on the cash flows (based on the amended building blocks).

Table 4: AER conclusion on benchmark equity raising cost for the NSW DNSPs ($m, nominal)

Cash flow analysis	Country Energy	EnergyAustralia	Integral Energy	Notes
Dividends	642.8	1040.6	546.9	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	192.8	312.2	164.1	30% of dividends paid
Cost of dividend reinvestment plans	1.9	3.12	1.6	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	4026.9	8229.2	2838.3	This is the forecast capex funding requirement (not the capex value that includes a half year WACC adjustment)
Debt component	2045.2	4802.5	1422.0	Set to equal 60% of RAB increase (not capex)
Equity component	1981.7	3426.7	1416.3	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	1515.4	2309.9	1195.8	Includes dividends reinvested
External equity requirement	466.3	1116.8	220.5	Equal to equity component less retained cash flows
External equity raising cost	12.8	30.7	6.1	External equity requirement multiplied by benchmark direct cost (2.75%)
Total equity raising cost	14.8	33.8	7.7	Sum of dividend reinvestment plan cost and external equity raising cost
Total equity raising cost ($2008–09)	14.3	31.7	7.5	To be added to the RAB at the start of the next regulatory control period

Tables 5, 6 and 7 set out the updated forecast operating expenditure allowance for EnergyAustralia over the next regulatory control period and replace tables 8.24 (and table 13), 8.25 and 8.26 respectively of the AER's 2009 final decision.

Table 5: AER conclusion on EnergyAustralia's total forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's revised controllable opex forecast	548.8	566.9	582.8	601.6	610.8	2910.9
Self insurance costs	5.9	5.9	5.9	5.9	5.9	29.6
Debt raising costs	7.6	9.0	10.1	11.4	12.6	50.8
Equity raising costs	–	–	–	–	–	–
EnergyAustralia's total opex	562.4	581.8	598.9	618.9	629.3	2991.3
AER's adjusted controllable opex	498.3	508.3	518.7	527.8	528.6	2581.8
Self insurance costs	4.1	4.1	4.1	4.1	4.1	20.6
Debt raising costs	3.9	4.5	5.0	5.6	6.2	25.2
Equity raising costs[a]	–	–	–	–	–	–
Demand management innovation allowance[b]	1.0	1.0	1.0	1.0	1.0	5.0
AER's total opex	507.3	517.9	528.8	538.6	540.0	2632.6

Note: Totals may not add up due to rounding.
(a) The AER will allow EnergyAustralia to amortise a total of $38.0 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(b) Refer to chapter 14 for details on this allowance.

Table 6: AER conclusion on EnergyAustralia's controllable opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's controllable opex allowance (draft decision)	490.2	502.8	518.5	535.1	545.3	2591.9
EnergyAustralia's revised controllable opex forecast	548.8	566.9	582.8	601.6	610.8	2910.9
Adjustment to network operating	–23.2	–27.9	–26.8	–28.0	–30.0	–135.9
Adjustment to network maintenance	–3.4	–4.3	–5.3	–6.8	–7.4	–27.2
Adjustment to other expenditure	–8.4	–8.8	–9.3	–9.0	–8.2	–43.8
Adjustment to labour escalators	–15.5	–17.6	–22.7	–29.9	–36.5	–122.2
AER's adjusted controllable opex	498.3	508.3	518.7	527.8	528.6	2581.8

Note: Totals may not add up due to rounding.

Table 7: AER conclusion on EnergyAustralia's total opex allowance—distribution and transmission ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Distribution network	472.2	483.0	494.1	503.8	505.8	2459.0
Transmission network	35.1	34.8	34.7	34.8	34.1	173.6
Total opex allowance	507.3	517.9	528.8	538.6	540.0	2632.6

Note: Totals may not add up due to rounding.

Table 8 sets out the updated forecast corporate income tax allowances for the next regulatory control period and replaces tables 9.4 and 15 of the AER's 2009 final decision.

Table 8: AER conclusion on the NSW DNSPs' corporate income tax allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	48.6	51.9	45.3	52.6	57.8	256.2
EnergyAustralia	43.0	75.2	86.0	98.2	104.2	406.5
Integral Energy	38.8	42.9	43.1	42.9	43.5	211.2

Table 9 sets out the updated forecast regulatory depreciation allowances for the next regulatory control period and replaces tables 10.4 and 16 of the AER's 2009 final decision.

Table 9: AER conclusion on the NSW DNSPs' regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	154.1	176.8	141.7	161.4	181.1	815.1
EnergyAustralia	80.0	107.0	131.2	156.9	152.2	627.2
Integral Energy	144.3	123.2	119.8	113.5	106.3	607.1

Table 10 sets out the updated forecast controllable operating expenditure for EnergyAustralia in respect of the efficiency benefit sharing scheme to apply over the next regulatory control period and replaces tables 13.2 and 19 of the AER's 2009 final decision.

Table 10: AER conclusion on EnergyAustralia's controllable opex for EBSS purposes ($m, 2008−09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total forecast opex	507.3	517.9	528.8	538.6	540.0	2632.6
Adjustment for debt raising costs	3.9	4.5	5.0	5.6	6.2	25.2
Adjustment for self insurance costs	4.1	4.1	4.1	4.1	4.1	20.6
Adjustment for insurance costs	6.1	6.1	6.1	6.1	6.1	30.4
Adjustment for superannuation costs	–	–	–	–	–	–
Adjustment for non–network alternatives	4.9	4.9	5.0	5.0	5.0	24.8
Forecast opex for EBSS purposes	488.4	498.3	508.7	517.8	518.6	2531.6

Note: Totals may not add up due to rounding.

Tables 11, 12, 13 and 14 set out the updated forecast roll forward of the regulatory asset bases for the next regulatory control period and replace tables 16.12, 16.14, 16.15 and 16.18 of the AER's 2009 final decision.

Table 11: AER roll forward of Country Energy's regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	4319.4	4931.4	5569.5	6283.6	7002.2
Net capex[a]	766.0	814.9	855.7	880.0	922.3
Indexation of opening RAB	106.9	122.0	137.8	155.5	173.3
Straight-line depreciation	–261.0	–298.9	–279.5	–316.9	–354.4
Closing RAB	4931.4	5569.5	6283.6	7002.2	7743.4

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

Table 12: AER roll forward of EnergyAustralia's transmission regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	1028.5	1309.4	1490.6	1749.4	2096.1
Net capex[a]	285.0	188.6	269.7	361.0	230.1
Indexation of opening RAB	25.5	32.4	36.9	43.3	51.9
Straight-line depreciation	–29.5	–39.8	–47.8	–57.6	–65.4
Closing RAB	1309.4	1490.6	1749.4	2096.1	2312.7

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

Table 13: AER roll forward of EnergyAustralia's distribution regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	7297.2	8433.9	9715.7	11 148.1	12 536.8
Net capex	1212.7	1381.4	1552.6	1531.2	1653.0
Indexation of opening RAB	180.6	208.7	240.4	275.9	310.3
Straight-line depreciation	–256.6	–308.3	–360.7	–418.5	–448.9
Closing RAB	8433.9	9715.7	11 148.1	12 536.8	14 051.1

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

Table 14: AER roll forward of Integral Energy's regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	3690.0	4149.9	4690.0	5174.2	5622.6
Net capex[a]	604.3	663.2	604.0	561.9	551.7
Indexation of opening RAB	91.3	102.7	116.1	128.1	139.2
Straight-line depreciation	–235.6	–225.9	–235.9	–241.5	–245.4
Closing RAB	4149.9	4690.0	5174.2	5622.6	6068.0

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes.

Tables 15, 16, 17 and 18 set out the updated forecast net tax allowance for the next regulatory control period and replace tables 16.13, 16.16, 16.17 and 16.19 respectively of the AER's 2009 final decision.

Table 15: AER modelling of net tax allowance for Country Energy ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	97.2	103.8	90.7	105.1	115.7
Less: value of imputation credits	48.6	51.9	45.3	52.6	57.8
Net tax allowance	48.6	51.9	45.3	52.6	57.8

Table 16: AER modelling of net tax allowance – EnergyAustralia distribution ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	78.7	135.1	154.3	175.5	185.4
Less value of imputation credits	39.3	67.5	77.1	87.7	92.7
Net tax allowance	39.3	67.5	77.1	87.7	92.7

Table 17: AER modelling of net tax allowance – EnergyAustralia transmission ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	7.3	15.2	17.7	20.9	23.0
Less: value of imputation credits	3.7	7.6	8.8	10.5	11.5
Net tax allowance	3.7	7.6	8.8	10.5	11.5

Table 18: AER modelling of net tax allowance for Integral Energy ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	77.6	85.7	86.2	85.8	87.1
Less: value of imputation credits	38.8	42.9	43.1	42.9	43.5
Net tax allowance	38.8	42.9	43.1	42.9	43.5

Tables 19, 20 and 21 set out the updated annual building block revenue requirement, expected revenues and resulting price impacts for Country Energy over the next regulatory control period and replace tables 16.20 (and table 21), 16.21 and 16.22 respectively of the AER's 2009 final decision.

Table 19: AER conclusion on Country Energy's annual revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		154.1	176.8	141.7	161.4	181.1
Return on capital		432.9	494.2	558.1	629.7	701.7
Tax allowance		48.6	51.9	45.3	52.6	57.8
Operating expenditure		405.4	424.0	442.8	461.2	477.9
TUOS adjustment		–44.9				
Annual revenue requirements		996.0	1146.9	1188.0	1304.8	1418.6
Expected revenues	732.3	856.8	1039.2	1260.8	1489.6	1474.5
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–13.41	–17.90	–17.90	–14.75	3.99

(a) Negative values for X factors indicate real price increases under the CPI–X formula.

Table 20: AER conclusion on Country Energy's annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirements	4515.3	996.0	1146.9	1188.0	1304.8	1418.6
Expected revenues	4515.3	856.8	1039.2	1260.8	1489.6	1474.5
Difference (%)	0.00	–13.98	–9.39	6.13	14.16	3.94

Table 21: Real end use price impacts – Country Energy proposal and AER decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy proposal	9.85	4.31	4.53	4.74	4.96
Updated AER final decision based on Tribunal orders	5.36	7.71	8.44	7.56	–2.18

Note: Calculations assume distribution costs contribute 40 per cent to the average residential customer's bill.

Tables 22, 23, 24 and 25 set out the updated annual building block revenue requirements, expected revenues and resulting price impacts for EnergyAustralia over the next regulatory control period and replace tables 16.23 (and table 22), 16.24 (and table 23), 16.25 and 16.26 respectively of the AER's 2009 final decision.

Table 22: AER conclusion on EnergyAustralia's annual revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		76.0	99.6	120.2	142.6	138.7
Return on capital		731.3	845.2	973.7	1117.2	1256.4
Tax allowance		39.3	67.5	77.1	87.7	92.7
Operating expenditure		483.9	507.2	531.7	555.5	571.6
Annual revenue requirements		1330.5	1519.6	1702.8	1903.1	2059.3
Expected revenues	1023.5	1224.3	1458.3	1738.5	2063.9	2076.5
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–17.86	–18.18	–18.18	–18.18	0.77

(a) Negative values for X factors indicate real price increases under the CPI–X formula.

Table 23: AER conclusion on EnergyAustralia's annual revenue requirements and X factors – transmission ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.0	7.4	11.0	14.3	13.5
Return on capital		103.1	131.2	149.4	175.3	210.1
Tax allowance		3.7	7.6	8.8	10.5	11.5
Operating expenditure		36.0	36.6	37.4	38.3	38.6
Annual revenue requirements		146.7	182.8	206.6	238.4	273.6
Expected revenues	129.5	143.0	173.6	210.7	255.8	267.4
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–7.77	–18.46	–18.46	–18.46	–2.02

(a) Negative values for X factors indicate real revenue increases under the CPI–X formula.

Table 24: AER conclusion on EnergyAustralia's annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Transmission						
Annual revenue requirements	771.9	146.7	182.8	206.6	238.4	273.6
Expected revenues	771.9	143.0	173.6	210.7	255.8	267.4
Difference (%)	0.00	–2.55	–5.07	2.00	7.27	–2.88
Distribution						
Annual revenue requirements	6319.6	1330.5	1519.6	1702.8	1903.1	2059.3
Expected revenues	6319.6	1224.3	1458.3	1738.5	2063.9	2076.5
Difference (%)	0.00	–7.99	–4.04	2.10	8.45	0.83

Table 25: Real end use price impacts – EnergyAustralia proposal and AER final decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Distribution					
EnergyAustralia proposal	15.72	6.88	7.36	7.83	8.30
Updated AER final decision based on Tribunal orders	7.15	8.00	8.75	9.51	–0.43
Transmission					
EnergyAustralia proposal	0.85	0.90	1.02	1.17	1.34
Updated AER final decision based on Tribunal orders	0.39	0.99	1.16	1.36	0.17

Note: Calculations assume distribution and transmission costs contribute 40 per cent and 5 per cent to the average residential customer's bill respectively.

Tables 26, 27 and 28 set out the updated annual building block revenue requirement, expected revenues and resulting price impacts for Integral Energy over the next regulatory control period and replace tables 16.27 (and table 24), 16.28 and 16.29 respectively of the AER's 2009 final decision.

Table 26: AER conclusion on Integral Energy's annual revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		144.3	123.2	119.8	113.5	106.3
Return on capital		369.8	415.9	470.0	518.5	563.5
Tax allowance		38.8	42.9	43.1	42.9	43.5
Operating expenditure		304.8	314.8	327.4	339.7	346.8
Annual revenue requirements		857.7	896.8	960.4	1014.6	1060.1
Expected revenues	652.8	749.9	874.3	1023.9	1077.6	1101.7
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–12.58	–13.00	–13.00	–0.15	1.72

(a) Negative values for X factors indicate real price increases under the CPI–X formula.

Table 27: AER conclusion on Integral Energy's annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirements	3591.6	857.7	896.8	960.4	1014.6	1060.1
Expected revenues	3591.6	749.9	874.3	1023.9	1077.6	1101.7
Difference (%)	0.00	–12.56	–2.51	6.62	6.21	3.93

Table 28: Real end use price impacts – Integral Energy revised regulatory proposal and AER final decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Integral Energy proposal	7.80	3.08	3.20	3.31	3.43
Updated AER final decision based on Tribunal orders	5.03	5.57	5.97	0.07	–0.84

Note: Calculations assume distribution costs contribute 40 per cent to the average residential customer's bill.

Tables 29 and 30 set out the updated annual revenue requirements and X factors for the next regulatory control period and replace tables 16.30 and 16.31 of the AER's 2009 final decision.

Table 29: AER conclusion on NSW DNSPs' annual revenue requirements ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	996.0	1146.9	1188.0	1304.8	1418.6
EnergyAustralia (distribution)	1330.5	1519.6	1702.8	1903.1	2059.3
EnergyAustralia (transmission)	146.7	182.8	206.6	238.4	273.6
Integral Energy	857.7	896.8	960.4	1014.6	1060.1

Table 30: AER conclusion on NSW DNSPs' X factors (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	–13.41	–17.90	–17.90	–14.75	3.99
EnergyAustralia (distribution)	–17.86	–18.18	–18.18	–18.18	0.77
EnergyAustralia (transmission)	–7.77	–18.46	–18.46	–18.46	–2.02
Integral Energy	–12.58	–13.00	–13.00	–0.15	1.72

The definition of the general nominated pass through event for EnergyAustralia set out in section 15.6.2 of the AER's 2009 final decision is replaced with the following:

A general nominated pass through event occurs in the following circumstances:

1. An uncontrollable and unforeseeable event the effect of which prudent operational risk management could not have prevented or mitigated that occurs during the next regulatory control period

2. The change in costs of providing distribution services as a result of the event is material

3. The event does not fall within any of the following definitions:

   'regulatory change event' in the NER (read as if paragraph (a) of the definition were not a part of the definition);

   'service standard event' in the NER;

   'tax change event' in the NER;

   'terrorism event' in the NER;

   'retail project event' in this final decision;

   'smart meter event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);

   'emissions trading scheme event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);

   'aviation hazards event' in this final decision.

For the purposes of this definition:

- an event will be considered unforeseeable if, at the time the DNSP lodged its regulatory proposal, despite the occurrence of the event being a possibility there was no reason to consider that the event was more likely to occur than not to occur during the next regulatory control period

- 'material' means the costs associated with the event would exceed 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.