Jemena Electricity Networks (Victoria) Ltd

Distribution determination 2011–2015

Pursuant to Orders of the Australian Competition Tribunal in *Application by United Energy Distribution Pty Limited (No 2)* [2012] ACompT 8

September 2012

AUSTRALIAN ENERGY REGULATOR

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Addendum

On 19 November 2010, Jemena Electricity Networks (Vic) Ltd (**JEN**) applied to the Australian Competition Tribunal (**Tribunal**) for review of various parts of its 2011–15 distribution determination. On 5 April 2012, the Tribunal made orders[1] requiring the AER to remake JEN's distribution determination by:

- replacing the figure "3.70%" for the debt risk premium in the distribution determination with the figure "4.34%";
- replacing the figure "0.5" as the value for gamma with figure "0.25" as the value for gamma when used as an input into calculation of the cost of corporate income tax;
- increasing the total capital expenditure allowance to include an amount in respect of the Broadmeadows project;
- increasing the total operating expenditure allowance to the amount claimed for the enterprise support function cost centres;
- remaking the final determination in respect of the indexation of the regulatory asset base (**RAB**).

In remaking this distribution determination:

- replacing the debt risk premium figure results in variations to JEN's weighted average cost of capital, public lighting charges, revenue requirements and X factors, capital expenditure, alternative control services prices and corporate income tax liability;
- replacing the value for gamma results in variations to JEN's corporate income tax liability, public lighting charges, revenue requirements and X factors, alternative control services prices and S factor close out;
- increasing the total capital expenditure results in variations to JEN's capital expenditure, revenue requirements and X factors, forecast roll-forward of the RAB, regulatory depreciation, and corporate income tax liability;
- increasing the total operating expenditure results in variations to JEN's operating expenditure, forecast controllable operating expenditure for the purposes of the efficiency benefit sharing scheme, revenue requirements and X factors, corporate income tax liability and efficiency carryover mechanism;
- indexing the regulatory asset base to six and a half years results in variations to JEN's forecast roll-forward of the RAB, revenue requirements and X factors, regulatory depreciation and corporate income tax liability.

[1] *Application by United Energy Distribution Pty Limited (No 2)* [2012] ACompT 8, Orders of ACT 10 of 2010.

Together, JEN's revenue requirements and X factors for the 2011–15 regulatory control period arising from the Tribunal's orders are detailed as below. The AER has determined JEN's X factors to minimise any price impact on consumers as far as reasonably possible in accordance with the National Electricity Rules.

	2011	2012	2013	2014	2015
Annual revenue requirements	193.3	196.9	214.6	218.0	218.2
X factors (per cent)	–4.99	–3.00	–7.97	–7.50	–3.40

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Shortened forms

AER	Australian Energy Regulator
AH	after hours
BH	business hours
capex	capital expenditure
CPI	Consumer Price Index
cl/cll.	clause/clauses
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DNSP	distribution network service provider
DUOS	distribution use of system
EBSS	efficiency benefit sharing scheme
ESCV	Essential Services Commission of Victoria
GSL	Guaranteed service level
GWh	gigawatt hours
m	million
MAIFI	momentary average interruption frequency index
MWh	megawatt hours
NDSC	Negotiated distribution services criteria
NEL	National Electricity Law
NER	National Electricity Rules
opex	operating expenditure
PTRM	post tax revenue model
RAB	regulatory asset base
s.	section
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
TUOS	transmission use of system
WACC	weighted average cost of capital
WAPC	weighted average price cap

Nature and authority

Clause 6.11.1 of the National Electricity Rules (NER) requires the Australian Energy Regulator (AER) to make a distribution determination in relation to Jemena Electricity Networks (Victoria) ABN 82 064 651 083 (JEN).

- Clause 6.2.3 states that classification forms part of a distribution determination and operates for the regulatory control period for which the distribution determination is made.
- Clause 6.2.5 (a) states that a distribution determination is to impose controls over the prices of direct control services, the revenue to be derived from direct control services or both.
- Chapter 10 states that an event nominated in a distribution determination as a pass through event is a pass through event for the determination (in addition to those listed in the NER, that is, a regulatory change event, a service standard event, a tax change event and a terrorism event).
- Clause 6.3.1 requires the AER to make a building block determination in relation to JEN as a component of a distribution determination. Clause 6.3.2(a) states that the building block determination is to specify the following matters for a regulatory control period:

  (1) the Distribution Network Service Provider's annual revenue requirement for each regulatory year of the regulatory control period;

  (2) appropriate methods for the indexation of the regulatory asset base;

  (3) how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme are to apply to the Distribution Network Service Provider;

  (4) the commencement and length of the regulatory control period;

  (5) any other amounts, values or inputs on which the building block determination is based (differentiating between those contained in, or inferred from, the service provider's building block proposal and those based on the AER's own estimates or assumptions).

- Clause 6.7.3 requires the AER to make a determination specifying requirements relating to the negotiating framework forming part of a distribution determination for a Distribution Network Service Provider is to set out requirements that are to be complied with in respect of the preparation, replacement, application or operation of its negotiating framework.
- Clause 6.7.4(a) requires the AER to make a determination by the AER specifying the Negotiated Distribution Service Criteria which form part of a distribution determination for a Distribution Network Service Provider. This is to set out the criteria that are to be applied:

  (1) by the providers in negotiating terms and conditions of access including:

(i) the prices that are to be charged for the provision of negotiated distribution services by the provider for the relevant regulatory control period; or

(ii) any access charges which are negotiated by the provider during that regulatory control period; and

(2) by the AER in resolving an access dispute about terms and conditions of access including:

(i) the price that is to be charged for the provision of a negotiated distribution service by the provider; or

(ii) any access charges that are to be paid to or by the provider.

- Clause 6.7.4(b) sets out that the Negotiated Distribution Service Criteria must give effect to and be consistent with the Negotiated Distribution Service Principles set out in clause 6.7.1.

- Clause 6.12.3(a) allows the AER the discretion to accept or approve, or refuse to accept or approve any element of a regulatory proposal.

- Clause 6.12.3(f) requires that if the AER refuses to approve an amount or value referred to in clause 6.12.1, the substitute amount or value on which the distribution determination is based must be:

  (1) determined on the basis of the current regulatory proposal; and

  (2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

The AER’s final distribution determination for JEN is detailed below. Detailed analysis and discussion of the AER’s considerations, reasoning and conclusions are set out in the AER’s *Final decision, Victorian distribution determination 2011–2015* dated 29 October 2010 which accompanies this distribution determination (the 'final decision').

The final decision is to be read in conjunction with the AER's *Draft decision, Victorian distribution determination 2011 to 2015* dated 4 June 2010 (the 'draft decision')

1 Service classification determination

In accordance with clause 6.2.1(a) and 6.12.1(1) of the NER, the AER determines the following classification of services for JEN for the 2011–2015 regulatory control period.

1.1 Direct control services (standard control services)

1.1.1 Network services

- Constructing the distribution network
- Maintaining the distribution network and connection assets
- Operating the distribution network and connection assets (for DNSP purposes)
- Designing the distribution network
- Planning the distribution network
- Emergency response
- Administrative support (for example, call centre, network billing)
- Location of underground cables

1.1.2 Connection services

- New connections requiring augmentations

1.2 Alternative control services

1.2.1 Fee based services

- Fault response (not DNSP fault)
- Energisation of new connections
- Temporary disconnect / reconnect services
- Wasted attendance (not DNSP fault)
- Service truck visits
- Fault level compliance service
- Reserve feeder
- Photovoltaic installation
- Routine connections (customers below 100 amps)

- Temporary supply services

1.2.2 Quoted services

- Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets
- Supply enhancement at customer request
- Emergency recoverable works (that is, emergency works where customer is at fault and immediate action needs to be taken by the DNSP)
- Auditing of design and construction
- Specification and design enquiry fees
- Elective underground service where an existing overhead service exists
- Damage to overhead service cables caused by high load vehicles
- High load escorts (lifting overhead lines)
- Covering of low voltage mains for safety reasons
- Routine connections (customers above 100 amps)
- Supply abolishment
- After hours truck by appointment.

1.2.3 Public lighting services - fee based

- Operation, repair, replacement and maintenance of DNSP public lighting assets

1.2.4 Metering services – fee based

- De-energisation of existing connections
- Re-energisation of existing connections
- Meter investigation
- Special meter reading
- Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh

1.3 Negotiated services

- Alteration and relocation of DNSP public lighting assets
- New public lighting assets (that is, new lighting types not subject to a regulated charge and new public lighting at green field sites)

1.4 Unregulated services

- The installation, maintenance and provision and repair of watchman (security) lights
- Provision of possum guards

2 Control mechanisms

In accordance with clause 6.2.5, 6.12.1(11) and 6.12.1(12), of the NER, the AER has decided that the following control mechanisms to apply to JEN's direct control services for the 2011–15 regulatory control period.

The AER's considerations, reasons and decision on control mechanisms are also set out in the final decision at chapters 4, 19 and 20, and appendices E, F, G and Q.

2.1 Standard control services

The following weighted average price cap (WAPC) formula is to apply to JEN:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1 + CPI_t) \times (1 - X_t) \times (1 + S_t) \times (1 + L_t) \pm (passthrough_t)$$

where a DNSP has *n* distribution tariffs, which each have up to *m* distribution tariff components, and where:

> *regulatory year "t"* is the regulatory year in respect of which the calculation is being made;
>
> *regulatory year "t-1"* is the regulatory year immediately preceding regulatory year "*t*";
>
> *regulatory year "t-2"* is the regulatory year immediately preceding regulatory year *"t-1"*;
>
> p_t^{ij} is the proposed distribution tariff for component *j* of distribution tariff *i* in regulatory year *t*;
>
> p_{t-1}^{ij} is the distribution tariff being charged in regulatory year *t-1* for component *j* of distribution tariff *i*;
>
> q_{t-2}^{ij} is the quantity of component *j* of distribution tariff *i* that was delivered in regulatory year *t-2*;
>
> CPI_t is calculated as follows:
>
>> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year *t*;
>>
>> **divided by**
>>
>> The Consumer Price Index, All Groups Index Number (weighted average of eight capital cities) published by the Australia Bureau of Statistics for the September Quarter immediately preceding the start of regulatory year *t-1*;

minus one.

X_t is the value of *X* for year *t* of the regulatory control period as determined by the AER in chapter 18 of the final decision;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*;

L_t is the licence fee pass through adjustment to be applied in regulatory year *t* in accordance with appendix E of the final decision; and

$passthrough_t$ represents approved pass through amounts with respect to regulatory year *t* as determined by the AER under clause 6.6 of the NER and chapter 16 and appendix E of the final decision.

With the side constraints formula to apply as follows:

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \times q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \times q_{t-2}^{ij}} \leq (1+CPI_t) \times (1-X_t) \times (1+S_t) \times (1+L_t) \times (1+2\%) \pm (passthrough_t)$$

Where for each tariff class a DNSP has *n* distribution tariffs, which each have up to *m* distribution tariff components, and where:

regulatory year "t" is the regulatory year in respect of which the calculation is being made;

regulatory year "t-1" is the regulatory year immediately preceding regulatory year "*t*";

regulatory year "t-2" is the regulatory year immediately preceding regulatory year *"t-1"*;

p_t^{ij} is the proposed distribution tariff for component *j* of distribution tariff *i* in regulatory year *t* ;

p_{t-1}^{ij} is the distribution tariff being charged in regulatory year *t-1* for component *j* of distribution tariff *i*;

q_{t-2}^{ij} is the quantity of component *j* of distribution tariff *i* that was delivered in regulatory year *t-2*;

CPI_t is defined as set out in chapter 4 of the final decision;

X_t is the value of *X* for year *t* of the regulatory control period as determined by the AER in chapter 18 of the final decision. If X>0, then *X* will be set equal to zero for the purposes of the side constraint formula;

S_t is the Service Target Performance Incentive Scheme factor to be applied in regulatory year *t*;

L_t is the licence fee pass through adjustment to be applied in regulatory year *t* in accordance with appendix E of the final decision; and

$passthrough_t$ represents approved pass through amounts with respect to regulatory year *t* as determined by the AER under clause 6.6 of the NER and chapter 16 and appendix E of the final decision.

2.2 Alternative control services

2.2.1 Public lighting

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to JEN's public lighting services is caps on the prices of individual services in each regulatory year of the forthcoming regulatory control period, as set out in table 1 below, and price paths for the remaining regulatory years of the forthcoming regulatory control period.

Table 1 Final determination on public lighting charges OMR for JEN ($, nominal)

Lighting service	2011	2012	2013	2014	2015
Mercury vapour 80 watt	37.93	40.16	~~42.27~~	~~44.67~~	~~47.37~~
			43.96	46.56	49.52
Sodium high pressure 150 watt	73.39	77.09	~~80.79~~	~~85.02~~	~~89.44~~
			83.47	87.98	92.78
Sodium high pressure 250 watt	75.22	79.05	~~82.86~~	~~87.21~~	~~91.77~~
			85.62	90.27	95.22
T5 2x14 watt	24.70	25.64	~~26.78~~	~~28.13~~	~~29.47~~
			27.57	29.00	30.42
Fluorescent 20 watt	47.41	50.20	~~52.84~~	~~55.84~~	~~59.22~~
			54.95	58.19	61.91
Fluorescent 40 watt	47.41	50.20	~~52.84~~	~~55.84~~	~~59.22~~
			54.95	58.19	61.91
Fluorescent 80 watt	47.41	50.20	~~52.84~~	~~55.84~~	~~59.22~~
			54.95	58.19	61.91
Mercury vapour 50 watt	47.41	50.20	~~52.84~~	~~55.84~~	~~59.22~~
			54.95	58.19	61.91
Mercury vapour 125 watt	55.75	59.03	~~62.14~~	~~65.67~~	~~69.64~~
			64.62	68.44	72.80
Mercury vapour 250 watt	72.22	75.89	~~79.54~~	~~83.72~~	~~88.10~~
			82.20	86.66	91.41
Mercury vapour 400 watt	81.24	85.38	~~89.49~~	~~94.18~~	~~99.12~~
			92.47	97.49	102.84
Sodium low pressure 90 watt	77.79	81.72	~~85.63~~	~~90.12~~	~~94.81~~
			88.47	93.26	98.34
Sodium high pressure 50 watt	91.74	96.36	~~100.98~~	~~106.27~~	~~111.81~~
			103.11	108.61	114.43

Sodium high pressure 100 watt	100.54	105.61	~~110.68~~	~~116.47~~	~~122.54~~
			114.35	120.53	127.10
Sodium high pressure 400 watt	100.05	105.14	~~110.20~~	~~115.98~~	~~122.06~~
			113.88	120.06	126.64
Sodium high pressure 250 watt (24 hours)	117.35	123.32	~~129.26~~	~~136.04~~	~~143.17~~
			132.01	139.07	146.57
Metal halide 70 watt	97.47	103.21	~~108.64~~	~~114.80~~	~~121.75~~
			112.98	119.65	127.28
Metal halide 150 watt	162.92	171.14	~~179.35~~	~~188.74~~	~~198.57~~
			185.29	195.32	205.96
Metal halide 250 watt	161.73	169.97	~~178.14~~	~~187.49~~	~~197.31~~
			184.09	194.08	204.72
Incandescent 100 watt	59.17	62.65	~~65.95~~	~~69.69~~	~~73.90~~
			68.58	72.63	77.26
Incandescent 150 watt	73.96	78.31	~~82.43~~	~~87.11~~	~~92.38~~
			85.73	90.78	96.57

Source: AER analysis.

2.2.2 Fee based alternative control services

In accordance with clause 6.12.1(12) of the NER, the control mechanism to apply to JEN's fee based alternative control services is caps on the prices of individual fee based alternative control services in the first regulatory year of the forthcoming regulatory control period, as set out in table 2 below, and price paths for the remaining regulatory years of the forthcoming regulatory control period. The approved price path consists of the 2011 price escalated by the X factors set out in table 3.

Table 2 AER final determination for JEN—fee based alternative control services prices for 2011 ($, 2010)

Fee based services	Draft decision price	Revised proposal price	AER final decision price	Difference between proposed price and AER price (per cent)
Manual—energisation of new premises—BH	10.10	12.00	11.74	–2%
Manual—energisation of new premises—AH	34.34	36.97	35.41	–4%
Manual—re-energisation Existing Premises—BH	10.10	12.00	11.74	–2%
Manual—re-energisation Existing Premises—AH	34.34	36.97	35.41	–4%
Manual de-energisation—Existing Premises—BH	16.53	20.14	20.06	0%
Manual de-energisation—Existing Premises—AH	37.46	41.75	40.56	–3%
Connection—temporary supply (overhead supply—coincident abolishment)—BH	239.24	368.00	420.11	14%
Connection—temporary supply (overhead supply—coincident abolishment)—AH	268.09	429.24	466.47	9%
Temporary disconnect—reconnect for non-payment—BH	28.40	29.35	28.77	–2%
Temporary disconnect—reconnect for non-payment—AH	40.43	41.74	40.53	–3%
Adjust time switch—BH only	10.02	10.38	10.83	4%
Manual special meter reads—BH only	6.59	8.15	8.67	6%
Service vehicle visit—BH	222.46	231.41	306.12	32%
Service vehicle visit—AH	330.63	344.72	337.25	–2%
Wasted service truck visit—not DNSP fault—BH	149.33	154.41	305.64	98%
Wasted service truck visit—not DNSP fault—AH	173.84	179.93	346.17	92%
Fault response—not DNSP fault—BH	242.32	252.29	258.13	2%

Fault response—not DNSP fault—AH	283.99	295.68	288.94	–2%
Retest of types 5 and 6 metering installations for first tier customers <160MWh—BH	237.22	241.32	233.23	–3%
Retest of types 5 and 6 metering installations for first tier customers <160MWh—AH	300.77	305.81	294.42	–4%
Retest of types 5 and 6 metering installations for first tier customers > 160MWh—BH	Further information requested	241.32	233.23	–3%
Retest of types 5 and 6 metering installations for first tier customers > 160MWh—AH	Further information requested	305.81	294.42	–4%
Reserve feeder ($/kW)	Further information requested	17.57	4.32	75%
Routine new connections where JEN is responsible for metering, customers<100amps				
Routine Connection—Single Phase service connection to new premises—BH	338.39	349.35	397.11	14%
Routine Connection—Single Phase service connection to new premises—AH	399.23	417.05	455.10	9%
Routine Connection—Three phase service connection to new premises with direct connected metering—BH	425.85	435.19	487.33	12%
Routine Connection—Three phase service connection to new premises with direct connected metering—AH	483.34	502.89	545.26	8%
Routine new connections where JEN is NOT responsible for metering, customers<100amps				
Routine Connection—Single Phase service connection to new premises—BH	Further information requested	349.35	397.11	14%
Routine Connection—Single Phase service connection to new premises—AH	Further information requested	417.05	455.10	9%
Routine Connection—Three phase service connection to new premises with direct connected metering—BH	Further information requested	435.19	487.33	12%

Routine Connection—Three phase service connection to new premises with direct connected metering—AH	Further information requested	502.89	545.26	8%

Note: While JEN disagreed with the AER’s draft decision labour rates and times for alternative control services, JEN’s revised proposal prices incorporated the AER’s draft decision labour rates and times for services, which have been revised upwards in the final decision. Accordingly, many of the final decision prices appear as an increase on JEN’s revised proposed prices.
JEN's build up model proposed prices in 2008 dollars. The AER has used JEN's Forecast Data Model submitted as part of its revised regulatory proposal to adjust the prices from 2008 dollars to 2010 dollars.

Table 3 AER final determination for JEN—X factors for fee based alternative control services (per cent)

	2012	2013	2014	2015
Business hours				
New Connection Services				
Connection—single phase service connection to new premises	–1.18	–1.47	–2.02	–1.35
Connection—three phase service connection to new premises with direct metering	–0.89	–1.12	–1.52	–1.02
Network Services				
Manual energisation of new premises	–1.86	–2.38	–3.16	–2.11
Manual re-energisation of existing premises	–1.86	–2.38	–3.16	–2.11
Manual de-energisation of existing premises	–1.88	–2.38	–3.18	–2.12
Temporary overhead supply— coincident abolishment	–1.47	–1.78	–2.49	–1.66
Temporary disconnect—reconnect for non-payment	–1.87	–2.38	–3.17	–2.11
Adjust time switch	–1.92	–2.38	–3.24	–2.15
Manual special meter reads	–1.87	–2.38	–3.16	–2.11
Service vehicle visit	–1.70	–2.04	–2.86	–1.90
Wasted service truck visit—not DNSP fault	–1.55	–1.88	–2.63	–1.75
Fault response—not DNSP fault	–1.72	–2.07	–2.90	–1.92
Meter test—single and multi phase meter installations with annual consumption of <160 MWh	–1.85	–2.38	–3.15	–2.10
Meter test—types 5 & 6 meter installation for first tier customers with annual consumption >160 MWh	–1.85	–2.38	–3.15	–2.10
After hours				
New connection services				
Connection—single phase service connection to new premises	–1.30	–1.61	–2.22	–1.48
Connection—three phase service connection to new premises with direct metering	–1.02	–1.29	–1.75	–1.18
Network Services				
Manual energisation of new premises	–1.85	–2.38	–3.14	–2.10

Manual re-energisation of existing premises	–1.85	–2.38	–3.14	–2.10
Manual de-energisation of existing premises	–1.86	–2.38	–3.15	–2.11
Temporary overhead supply—coincident abolishment	–1.54	–1.86	–2.61	–1.73
Temporary disconnect—reconnect for non-payment	–1.86	–2.38	–3.15	–2.11
Service vehicle visit	–1.79	–2.16	–3.01	–2.00
Wasted service truck visit—not DNSP fault	–1.61	–1.95	–2.73	–1.81
Fault response—not DNSP fault	–1.76	–2.12	–2.96	–1.96
Meter test—single and multi phase meter installations with annual consumption of <160 MWh	–1.85	–2.38	–3.14	–2.10
Meter test—types 5 & 6 meter installation for first tier customers with annual consumption >160 MWh	–1.85	–2.38	–3.14	–2.10

Note: X factors for new connections services where JEN is responsible for metering are identical to those where JEN is not responsible for metering.

Source: JEN, *Response to AER information request of 12 October 2010*, 18 October 2010.

2.2.3 Quoted alternative control services

In accordance with clause 6.12.1(12) of the NER, the control mechanism for JEN's quoted alternative control services consists of caps on the applicable labour rates in the first regulatory year of the forthcoming regulatory control period, set out in Table 4 below, and price paths for the labour rates for the remaining regulatory years of the forthcoming regulatory control period. The approved price path consists of the 2011 quoted services labour rate escalated by the X factors set out in Table 5. Materials for quoted services are to be recovered at cost.

Table 4 AER final determination for JEN—quoted alternative control services charge out rates for 2011 ($, 2010)

Quoted services	AER draft decision $/hour rate	Revised proposed $/hour rate	AER final decision $/hour rate	Difference between proposed rate and AER rate (per cent)
Unit rate per man hour—BH	79.80	81.82	81.82	0%
Unit rate per man hour—AH	99.75	101.28	101.28	0%

Table 5 AER final determination for JEN—X factors for quoted alternative control services labour rates (per cent)

	2012	2013	2014	2015
X (per cent)	–1.98	–2.38	–3.33	–2.20

3 Building block determination

3.1 Revenue requirement

In accordance with clause 6.3.2(a)(1) and 6.12.1(2) of the NER, the AER rejects JEN's proposed annual revenue requirement for each regulatory year of forthcoming regulatory control period. In accordance with clause 6.12.1(2) and 6.12.1(11) of the NER, the AER's final determination on JEN's revenue requirements and X factors is set out in table 6 below. The AER's considerations, reasons and decision on the annual revenue requirement for JEN are also set out in the final decision at chapter 18.[2]

[2] The relevant inputs into this table are discussed in the final decision as follows – chapter 10 (depreciation), chapter 11 (cost of capital), chapter 7 (opex), chapter 13 (efficiency measurements – ESCV's ECM 2006-2010), chapter 12 (corporate income tax and imputation credits), chapter 18 (overall revenue requirement and x factors) and chapter 15 (service target performance incentive scheme).

Table 6 AER final determination on revenue requirements and X factors for JEN ($'m, nominal)

	2010	2011	2012	2013	2014	2015
Return on capital		~~75.2~~	~~80.8~~	~~87.1~~	~~93.2~~	~~99.6~~
		78.9	86.3	92.8	99.1	105.8
Regulatory depreciation		~~26.6~~	~~31.7~~	~~37.7~~	~~43.0~~	~~42.9~~
		26.4	31.9	37.9	43.3	43.8
Operating expenditure		~~57.5~~	~~57.8~~	~~59.4~~	~~66.4~~	~~67.0~~
		59.7	60.1	61.9	69.0	69.7
Efficiency carryover amounts		~~20.4~~	~~14.6~~	~~16.9~~	~~–0.7~~	0.0
		18.2	12.3	15.1	-2.1	
S factor amounts		5.6	1.0	–0.2	–0.2	~~–11.1~~
						-10.9
Tax allowance		~~2.9~~	~~3.4~~	~~4.4~~	~~5.5~~	~~5.9~~
		4.4	5.3	7.1	8.9	9.9
Annual revenue requirements		~~188.2~~	~~189.3~~	~~205.3~~	~~207.2~~	~~204.3~~
		193.3	196.9	214.6	218.0	218.2
Expected revenues	168.8	179.8	190.1	~~199.3~~	~~209.1~~	~~220.8~~
				209.0	228.7	242.5
Forecast CPI (per cent)		2.57	2.57	2.57	2.57	2.57
X factors (per cent)		–4.99	–3.00	~~–3.00~~	~~–3.00~~	~~–3.00~~
				–7.97	–7.50	–3.40

Note: Negative values for X indicate real price increases under the CPI-X formula.

3.2 Indexation of regulatory asset base

In accordance with clause 6.3.2(a)(2) of the NER, an appropriate methodology for indexation of JEN's regulatory asset base is the same as that used to escalate the form of control mechanism for that relevant year—that is, to apply the annual change in the Consumer Price Index: All Groups Index for the Eight State Capitals as published by the Australian Bureau of Statistics for the September quarter immediately preceding the start of the relevant regulatory year.

3.3 Schemes

3.3.1 EBSS

In accordance with clause 6.3.2(a)(3) and 6.12.1(9) of the NER, the AER has decided to apply the AER's *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008 to JEN for the 2011–15 regulatory control period. In determining how the EBSS is to be applied, the AER has decided that:

- The excluded cost categories for JEN are:
  - debt raising costs
  - self insurance costs
  - superannuation costs for defined benefits and retirement schemes
  - the DMIA
  - GSL payments.
- These excluded costs will be recognised in addition to the adjustments set out in section 2.3.2 of the EBSS.
- For the purpose of calculating carryover amounts, the AER will substitute actual values for customer numbers, the number of distribution transformers and zone substation capacity MVA and line length for the years 2011–14 and a revised forecast for 2015, for the forecasts of these metrics used in the final decision using the scale escalation method described in appendix J of the final decision.

The AER's determination on controllable opex for the EBSS is set out in Table 7.

The AER's considerations, reasons and conclusion on the application of the EBSS are also set out in the final decision at chapter 14.

Table 7 AER final determination on JEN's forecast controllable opex for EBSS purposes ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Total forecast opex	~~56.04~~	~~54.90~~	~~55.08~~	~~60.01~~	~~59.00~~	~~285.02~~
	58.21	57.11	57.33	62.31	61.34	296.31
Adjustment for debt raising costs	~~-0.44~~	~~-0.46~~	~~-0.48~~	~~-0.50~~	~~-0.52~~	~~-2.41~~
	-0.45	-0.48	-0.50	-0.52	-0.54	-2.48
Adjustment for self insurance	-0.10	-0.10	-0.10	-0.10	-0.10	-0.52
Adjustment for defined benefit superannuation	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for non-network alternatives	0.00	0.00	0.00	0.00	0.00	0.00
Adjustment for DMIA	-0.20	-0.20	-0.20	-0.20	-0.20	-1.00
Adjustment for GSL payments	-0.02	-0.02	-0.02	-0.02	-0.02	-0.09
Forecast opex for EBSS purposes	**~~55.28~~**	**~~54.12~~**	**~~54.28~~**	**~~59.18~~**	**~~58.15~~**	**~~281.01~~**
	57.44	**56.32**	**56.51**	**61.47**	**60.48**	**292.22**

Note: Totals may not add up due to rounding.

3.3.2 DMIS

In accordance with clause 6.3.2(a)(3) and 6.12.1(9) of the NER, the AER has decided to apply the *Demand management incentive scheme—CitiPower, Powercor, Jemena, SP AusNet and United Energy, April 2009* to JEN for the 2011–15 regulatory control period. In determining how the DMIS is to be applied, the AER has decided that:

- Part A of the DMIS (that is, the DMIA) will apply to JEN. Part B (the forgone revenue component) will also apply to JEN.
- The DMIA is capped at $1 million for the forthcoming regulatory control period and allocated to JEN in equal annual instalments of $200 000 (real $2010) for each year of the forthcoming regulatory control period.
- Approval of DMIA amounts by the AER will be subject to satisfaction of the DMIA criteria in the DMIS.

The AER's considerations, reasons and conclusion on the application of the DMIS are also set out in the final decision at chapter 17.

3.3.3 STPIS

In accordance with clause 6.3.2(a)(3) and 6.12.1(9) of the NER, the AER has decided to apply the *Electricity distribution network service providers, Service target performance incentive scheme, November 2009* to JEN for the 2011–15 regulatory control period. In determining how the STPIS is to be applied, the AER has decided that:

- The applicable parameters are the unplanned SAIDI, unplanned SAIFI and MAIFI reliability of supply parameters, and the telephone answering customer service parameter, defined as follows:

> Unplanned SAIDI: The sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIDI excludes momentary interruptions (one minute or less).
>
> Unplanned SAIFI: The total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.[3]
>
> MAIFI: The total number of momentary interruptions divided by the total number of distribution customers (where the distribution customers are network or per feeder based, as appropriate).[4]
>
> Telephone answering: Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to calls to payment lines and automated interactive services; and calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned.

- For the reliability of supply parameters JEN's network will be segmented into urban and short rural feeder types, and the performance target to apply to each applicable parameter in every regulatory year of the regulatory control period are set out in table 8.

- In accordance with clause 2.5(a) of the STPIS the cap on revenue at risk is set at ±5 per cent. In accordance with clause 5.2(b) of the STPIS there is a cap on the revenue at risk of ±0.5 per cent for the telephone answering parameter.

- The incentives rate to apply to each applicable parameter are calculated in accordance with clauses 3.2.2, 5.3.2(a)(1) and appendix B of the STPIS, and are set out in table 9. The values of customer reliability to be applied in accordance with clause 3.2.2(b) and appendix B of the STPIS are set out in table 10.

- The building blocks to apply as a result of the close out of the ESCV S factor scheme are calculated in accordance with section 15.6.6 of the final decision, and are set out in table 11.

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3 Defined as per the AER's *STPIS,* November 2009, pp. 22-23. SAIDI is measured by average minutes, SAIFI and MAIFI are measured by average interruptions.

4 As a transitional provision and in accordance with clause 2.6(c) of the STPIS, the AER has decided to apply the definition of MAIFI as previously adopted in Victoria under the ESCV's *Information Specification (Service Performance) for Victorian Electricity Distributors,* 1 January 2009, p. 30; For the definition of MAIFI, momentary interruptions are as defined in the *Information Specification (Service Performance) for Victorian Electricity Distributors,* 1 January 2009, p. 30

- As required under clause 6.6.2(b)(2) of the NER, and clauses 2.1(c) and 6.1 of the STPIS, the AER will apply the GSL scheme specified in section 6 of the Electricity Distribution Code and section 2.5 of the Public Lighting Code.[5] The AER concludes that, pursuant to clause 6.5.6(a)(2) of the NER, it will include forecast nominal GSL payments of $18 892 as a line item in the opex allowance, for each year in the 2011–15 regulatory period.

- The major event day threshold is set to exclude natural events which are more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years' SAIDI data. The major event day threshold is to be calculated in accordance with section 3.3 of the STPIS.

- The 'St' factor derived under the STPIS and applied to the WAPC formula for 2011 and 2012 will be zero.

The AER's considerations and reasons are set out in chapter 15 of the final decision, and the AER's conclusion on the application of the STPIS is set out below.

Table 8 AER conclusion on the performance targets for SAIDI, SAIFI, MAIFI and the telephone answering parameter for JEN

Feeder	Parameter	JEN
Urban	SAIDI	68.498
	SAIFI	1.127
	MAIFI	0.776
Rural short	SAIDI	153.150
	SAIFI	2.588
	MAIFI	1.940
Customer service parameter	Telephone answering	61.16

5 ESCV, Electricity Distribution Code, February 2010, p.19; ESCV, Public Lighting Code, April 2005, p.3.

Table 9 AER conclusion on the incentive rates for SAIDI, SAIFI, MAIFI and the telephone answering parameter for JEN

Feeder	Parameter	JEN
Urban	SAIDI	0.1054
	SAIFI	6.6017
	MAIFI	0.5281
Rural short	SAIDI	0.0046
	SAIFI	0.2949
	MAIFI	0.0236
Customer service parameter	Telephone answering	–0.040

Table 10 AER conclusion on the value of customer reliability ($, MWh)

	Value of customer reliability
Urban	50 867
Rural short	50 867

Table 11 AER conclusion on the building blocks resulting from the ESCV S factor close out ($ million, 2010)

	2011	2012	2013	2014	2015
JEN	5.46	0.92	– 0.20	– 0.19	~~–9.75~~
					–9.63

3.4 Regulatory control period

In accordance with clause 6.3.2(a)(4) and 6.12.1 (2) of the NER, the regulatory control period is five years long, commencing 1 January 2011 and ceasing on 31 December 2015.

3.5 Other amounts, values or inputs

In accordance with clause 6.3.2(a)(5) and 6.12.1(10) of the NER, any other amounts, values or inputs on which JEN's building block determination is based are as specified below.

3.5.1 Opening regulatory asset base and roll forward

In accordance with clause 6.12.1(6), 6.5.1 and Schedule 2 of the NER, the opening regulatory asset base for JEN as at 1 January 2011 is $756.5 million for standard control services.

Table 12 sets out the AER's decision for rolling-forward JEN's RAB during the 2011–15 regulatory control period.

The AER's considerations, reasons and decision on the RAB for JEN are also set out in the final decision at chapters 9 and 18.

Table 12 AER forecast roll-forward of the RAB for JEN ($'m, nominal)

	2011	2012	2013	2014	2015
Opening RAB	~~756.5~~	~~812.4~~	~~875.8~~	~~936.9~~	~~1 001.0~~
	764.2	835.1	898.5	959.7	1,023.9
Net capital expenditure[a]	~~82.5~~	~~95.1~~	~~98.8~~	~~107.1~~	~~99.3~~
	97.3	95.4	99.1	107.5	99.7
Indexation of opening RAB	~~19.5~~	~~20.9~~	~~22.6~~	~~24.1~~	~~25.8~~
	19.7	21.5	23.1	24.7	26.4
Straight-line depreciation	~~–46.1~~	~~–52.6~~	~~–60.2~~	~~–67.2~~	~~–68.7~~
	– 46.1	– 53.4	–61.1	– 68.0	–70.2
Closing RAB	~~**812.4**~~	~~**875.8**~~	~~**936.9**~~	~~**1 001.0**~~	~~**1 057.4**~~
	835.1	**898.5**	**959.7**	**1,023.9**	**1,079.8**

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.

3.5.2 Capital expenditure

In accordance with clause 6.5.7(d) and 6.12.1(3)(ii) of the NER, the AER does not accept JEN's proposed forecast capex for the forthcoming regulatory control period. The AER's considerations, reasons and decision on its estimate of the total of JEN's required capex for the 2011–15 regulatory control period are set out in chapter 8 of the final decision.

The AER's estimate of the total of JEN's required capex for the forthcoming regulatory control period is set out in table 13.[6]

[6] The relevant inputs into forecast capex are discussed in the final decision as follows – chapter 6 (outsourcing and related party transactions), appendix N (equity raising costs) and appendix P

Table 13 AER final determination on capital expenditure for JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
Gross direct capex	~~81.3~~	92.1	91.3	94.8	86.2	~~445.8~~
	94.7					459.2
Direct overheads	~~1.6~~	1.8	1.8	1.9	1.7	~~8.9~~
	1.9					9.2
Indirect overheads	2.6	2.6	2.7	2.7	2.8	13.4
Cost increases	-0.4	0.2	1.0	2.1	2.5	5.3
Margins	0.0	0.0	0.0	0.0	0.0	0.0
Less contributions	~~7.3~~	~~7.3~~	~~8.3~~	~~8.0~~	~~8.7~~	~~39.5~~
	7.2	7.2	8.1	7.9	8.5	38.8
Total net capex	**~~77.8~~**	**~~89.4~~**	**~~88.5~~**	**~~93.6~~**	**~~84.6~~**	**~~433.9~~**
	91.6	**89.6**	**88.7**	**93.7**	**84.7**	**448.3**

Note: numbers may not add exactly due to rounding

3.5.3 Rate of return

In accordance with clause 6.12.1(5) of the NER, the AER's decision on JEN's rate of return (the WACC) is set out in table 14.

The AER's considerations, reasons and decision the rate of return for JEN are also set out in the final decision at chapter 11.

Table 14 AER final determination on WACC parameters for JEN

Parameter	JEN
Nominal risk-free rate	5.65%
Real risk-free rate	2.99%
Expected inflation rate	2.57%
Gearing level (debt/equity)	60%
Market risk premium	6.50%
Equity beta	0.8
Debt risk premium	~~3.70%~~
	4.34%
Nominal pre-tax return on debt	~~9.35%~~
	9.99%
Nominal post-tax return on equity	10.85%
Nominal WACC	~~9.95%~~
	10.33%

3.5.4 Depreciation

In accordance with clause 6.12.1(8) of the NER, the AER does not approve JEN's submitted depreciation schedule. The AER's decision determining depreciation schedules in accordance with clause 6.5.5(b) of the NER is set out in table 15.

Table 15 AER final determination on regulatory depreciation for JEN ($'m, nominal)

	2011	2012	2013	2014	2015	Total
JEN	~~26.6~~	~~31.7~~	~~37.7~~	~~43.0~~	~~42.9~~	~~181.9~~
	26.4	31.9	37.9	43.3	43.8	183.5

3.5.5 Forecast operating expenditure

In accordance with clause 6.5.6(d) and 6.12.1(4)(ii) of the NER, the AER does not accept JEN's proposed forecast opex for the forthcoming regulatory control period. The AER’s considerations, reasons and decision on its estimate of the total of JEN's required opex for the 2011–15 regulatory control period are set out in chapter 7 of the final decision.

The AER's estimate of the total of JEN's required opex for the 2011–15 regulatory control period is set out in 3.5.5.[7]

Table 16 AER final determination on operating expenditure for JEN ($'m, 2010)

	2011	2012	2013	2014	2015	Total
JEN proposed opex	**66.1**	**65.1**	**65.5**	**70.7**	**73.5**	**340.8**
AER opex build–up[a]						
AER base year costs	~~46.3~~	~~46.3~~	~~46.3~~	~~46.3~~	~~46.3~~	~~231.7~~
	48.5	48.5	48.5	48.5	48.5	242.3
AER scale escalation	0.3	0.5	0.8	~~1.0~~	1.3	~~3.8~~
				1.1		4.0
AER real cost escalation	0.5	~~1.0~~	~~1.7~~	~~2.6~~	~~3.3~~	~~9.2~~
		1.1	1.8	2.7	3.4	9.6
AER step changes[b]	8.2	6.2	5.5	9.2	7.2	36.3
AER debt raising costs	0.4	0.5	0.5	0.5	0.5	~~2.4~~
						2.5
AER self insurance	0.1	0.1	0.1	0.1	0.1	0.5
AER other (GSL)	–	–	–	–	–	0.1
AER total opex	**~~55.8~~**	**~~54.7~~**	**~~54.9~~**	**~~59.8~~**	**~~58.8~~**	**~~284.0~~**
	58.0	**56.9**	**57.1**	**62.1**	**61.1**	**295.3**
Adjustment	**~~–10.2~~**	**~~–10.4~~**	**~~–10.6~~**	**~~–10.9~~**	**~~–14.7~~**	**~~–56.8~~**
	-8.1	**-8.2**	**-8.3**	**-8.6**	**-12.4**	**-45.5**
Adjustment (per cent)	**~~–15.5~~**	**~~–15.9~~**	**~~–16.1~~**	**~~–15.4~~**	**~~–20.0~~**	**~~–16.7~~**
	-12.2	**-12.5**	**-12.7**	**-12.1**	**-16.8**	**-13.3**

Source: AER analysis.
[a]Excludes DMIA allowance.
[b]Includes real cost escalation.

3.5.6 Cost of corporate income tax

In accordance with clause 6.12.1(7) of the NER, the AER’s decision on the estimated cost of corporate income tax for JEN is set out in table 17.

[7] The relevant inputs to this table are discussed in the final decision as follows: chapter 6 (outsourcing), chapter 13 (efficiency carryover mechanism), appendix H (benchmarking), appendix I (United Energy forecast opex) appendix J (scale escalation), appendix K (real cost escalation), appendix L (step changes), appendix M (self insurance, appendix N (debt raising costs).

The AER's considerations, reasons and decision on cost of corporate income tax for JEN are also set out in the final decision at chapter 12.

Table 17 AER final determination on corporate income tax liability for JEN ($'m, nominal)

	2011	2012	2013	2014	2015
JEN	~~2.9~~	~~3.4~~	~~4.4~~	~~5.5~~	~~5.9~~
	4.4	5.3	7.1	8.9	9.9

3.5.7 Other values, amounts and inputs

In accordance with clause 6.12.1(10) of the NER, the AER has decided other values, amounts and inputs.

These other values, amounts and inputs relate to growth forecasts, the ESCV's s-factor carryover amounts, and the ESCV's efficiency carryover mechanism (ECM) carryover amounts.

The AER's considerations, reasons and decisions on growth forecasts, s-factor carryover amounts and ECM carryover amounts for JEN are set out in the draft decision at chapters 5, 13 and 15 respectively. The AER's decisions on these additional inputs for JEN are set out in table 18, 19 and 20.

Table 18 AER determination on growth forecasts—JEN

	2011	2012	2013	2014	2015
Sum of non-coincident zone substations (MW)	1 099	1 130	1 161	1 192	1 212
Energy consumption (GWh)	4 334	4 322	4 271	4 222	4 205
Customer numbers	310 165	315 890	320 889	325 174	329 428

Table 19 AER final determination on building block amounts resulting from ESCV ECM carryover for JEN ($'m, 2010)

	2011	2012	2013	2014	Total
JEN	~~19.9~~	~~13.9~~	~~15.6~~	~~–0.6~~	~~48.7~~
	17.7	11.7	14.0	–1.9	41.6

Table 20 AER conclusion on the building blocks resulting from the ESCV S factor close out ($ million, 2010)

	2011	2012	2013	2014	2015
JEN	5.46	0.92	– 0.20	– 0.19	~~–9.75~~
					–9.63

4 Pass through events

In accordance with clause 6.12.1(14) of the NER, the AER has decided that the additional (nominated) pass through events listed below are apply to JEN are listed below.

The AER's considerations, reasons and decision on pass throughs are also set out in chapter 16 of the final decision.

- a declared retailer of last resort event:

  A declared retailer of last resort event is the occurrence of an event whereby an existing retailer is unable to continue to supply electricity to its customers and those customers are transferred to the declared retailer of last resort, and which:

  (a) falls within no other category of pass through event; and

  (b) materially increases the costs of providing direct control services.

  For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs are incurred

- insurer credit risk event:

  An event where the insolvency of the DNSP's insurer, as a result of which the DNSP:

  (a) incurs materially higher or lower costs for insurance premiums than those allowed for in the distribution determination; or

  (b) in respect of a claim for a risk that would have been insured by the DNSP's insurers, is subject to materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy.

  (c) incurs additional costs associated with self funding an insurance claim, which, would have otherwise been covered by the insolvent insurer.

  For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs are incurred

- an insurance event:

  An insurance event occurs if:

  (a) the DNSP makes a claim on an insurance policy that it holds; and

  (b) the DNSP incurs costs beyond the policy limit for the relevant insurance policy; and

(c) the DNSP must bear the costs that are in excess of the policy limit; and

(d) the event materially increases the costs to the DNSP of providing direct control services.

For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs are incurred.

For the purpose of this event, a relevant insurance policy refers to the policy coverage provided through a DNSP ' s forecast operating expenditure allowance for an insured risk, as approved by the AER in its distribution determination and the reasons for the determination.

- a natural disaster event:

Any major fire, flood, earthquake, or other natural disaster beyond the control of the DNSP (but excluding those events for which external insurance or self insurance has been included within the DNSP's forecast operating expenditure) that occurs during the forthcoming regulatory control period and materially increases the costs to the DNSP of providing direct control services.

For the purpose of this event, an event is considered to materially increase costs where the event has an impact of one per cent of the smoothed forecast revenue of the regulatory year in which the costs are incurred.

- A network charges event

A network charge pass through event occurs on an event date, if:

(a) during the event period to which the event date relates, the DNSP has incurred or saved or, in respect of the event period referred to in paragraph (i), is likely to incur or save, event costs; and

(b) those event costs are material.

The event costs are:

(c) charges for connection to the transmission system; and

(d) charges under Division 5A of Part 2 of the Electricity Industry Act 2000 (Vic) or rule 5.5(h) of the National Electricity Rules; and

(e) charges the DNSP pays to other DNSPs in respect of the provision of distribution services net of similar charges the DNSP receives from other DNSPs,

to the extent that these costs are not otherwise recoverable under the National Electricity Rules in force at the time the event occurs or when an application in relation to those costs is made under clause 6.6.1 of the National Electricity Rules.

An event date in relation to each event period referred to in paragraphs (f) to (i) is 1 June 2011, 1 June 2012, 1 June 2013 or 1 June 2014 respectively.

An event period is:

(f) from 1 January 2011 to 31 May 2011; or

(g) from 1 June 2011 to 31 May 2012; or

(h) from 1 June 2012 to 31 May 2013; or

(i) from 1 June 2013 to 31 December 2015.

For the purpose of this event, the event costs in respect of an event period are material if the total of those costs has an impact of, or more than, 1 per cent of the smoothed forecast revenue specified in the final decision for the applicable regulatory year(s), pro rata for the applicable event period.

5 Negotiating framework determination

In accordance with clause 6.12.3(g) and 6.12.1(15) of the NER, the AER has decided to apply JEN's proposed negotiating framework.

The AER's considerations, reasons and decision on negotiating frameworks are also set out in chapter 3 of the final decision. The approved negotiating framework is set out at appendix C of the final decision.

6 Negotiated distribution services criteria determination

In accordance with clause 6.7.4 and 6.12.1 (16) of the NER, the negotiated distribution services criteria (NDSC) the AER has decided to apply to JEN are set out at appendix D of the final decision. The AER’s considerations, reasons and decision on the NDSC are also set out in chapter 3 final decision.

7 Other constituent decisions

In accordance with clause 6.12.1(13) of the NER, the AER has decided that compliance with the relevant control mechanisms for direct control services is to be demonstrated as follows.

7.1 Compliance with control mechanisms

7.1.1 Standard control services

Compliance with the control mechanism for standard control services will be monitored as set out in appendix E of the final decision.

7.1.2 Alternative control services

Compliance with the control mechanisms for fee based and quoted alternative control services will be demonstrated through an annual pricing proposal process, described in section 20.6.3.3 of the final decision.

Compliance with the control mechanism for public lighting services is to be demonstrated by JEN through the annual pricing approval process and be consistent with the AER's decision for the relevant regulatory year. Operation, maintenance and repair charges approved by the AER will be subject to CPI adjustment for each year of the forthcoming regulatory control period.

7.2 Procedures for assigning customers to tariff classes

In accordance with clause 6.12.1(17), the AER has decided the procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another, as set out in appendix G of the final decision.

7.3 Depreciation for establishing the RAB as at the commencement of the following regulatory control period

In accordance with clause 6.12.1(18), the AER has decided that depreciation based on actual capital expenditure will be used to determine JEN's regulatory asset base as at the commencement of the following regulatory control period.

7.4 Recovery of TUOS charges

7.4.1 Recovery of 6.18.7 charges[8]

In accordance with clause 6.12.1(19) of the NER, the AER has decided how JEN is to report to the AER on its recovery of transmission use of system charges for each regulatory year of the forthcoming regulatory control period as set out in appendix F of the final decision.

[8] 6.18.7 charges are the charges referred to in clause 6.18.7 of the NER.

7.4.2 Recovery of 6.18.7A charges[9]

In accordance with clause 6.12.1(20) of the NER, the AER has decided how JEN is to report to the AER on its recovery of jurisdictional scheme amounts for each regulatory year of the 2011–15 regulatory control period as set out in appendix F of the final decision.

9 6.18.7A charges are the amounts referred to in clause 6.18.7A of the NER.