VICTORIAN RELIABILITY SUPPORT – PROJECT SPECIFICATION CONSULTATION REPORT

PREPARED BY: Planning

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FINAL

Executive Summary

AEMO currently procures a network loading control ancillary service (NLCAS) on the Murray-Dederang 330 kV lines which allows for greater use of inter-regional network capabilities between New South Wales and Victoria.

The existing NLCAS contract expires in July 2012, and AEMO is undertaking this Regulatory Investment Test for Transmission (RIT-T) application to assess the market benefits from increasing power transfer capability from New South Wales to Victoria from summer 2012–13 onwards.

This RIT-T application is the first stage in an ongoing process to assess market benefits from increasing power transfer capability between New South Wales and Victoria, focusing on the benefits to be gained in the short-term after the discontinuation of the NLCAS scheme. For this reason the credible options in this RIT-T have been limited to those that can be implemented within one or two years. AEMO will continue to assess options with longer implementation timeframes as part of its normal planning processes.

The RIT-T is an economic cost-benefit test which is used to assess and rank different electricity transmission investment options that address an identified need to invest. Its purpose is to identify the investment option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market.

This Project Specification Consultation Report (PSCR) is the first stage of the RIT-T process and shows:

- That during Victorian peak demand periods import from New South Wales is limited by the thermal capability of the Murray-Dederang 330 kV lines.
- That an increase in the thermal capability of the Murray-Dederang 330 kV lines of approximately 300 MW at peak demand times could lead to gross market benefits with a present value of $16.2 million over the period from 2012–13 to 2017–18.
- Discusses the credible options that could lead to net market benefits, specifically a non-network demand management option consisting of either:
  - a load reduction control scheme to allow the Murray-Dederang 330 kV lines to be operated at a higher short term rating (5-minute), or
  - a demand side response option to voluntarily curtail load at a cost less than the cost of involuntary load reduction.
- Sets out the technical requirements for the above non-network options.
- Identifies the preferred option: a non-network demand management option with costs less than the expected market benefits.
- Notes the reasons why AEMO considers this RIT-T application exempt from producing a Project Assessment Draft Report.

The second stage and final stage of this RIT-T process, publication of the Project Assessment Conclusion Report (PACR), is expected by the end of April 2012.

AEMO welcomes written submissions on this Project Specification Consultation Report (PSCR), particularly in relation to the preferred option presented and issues addressed in this report.

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1 Introduction

This Project Specification Consultation Report (PSCR) has been prepared by the Australian Energy Market Operator (AEMO) in accordance with the requirements of National Electricity Rules (NER) clause 5.6.6 and AEMO's capacity as the Transmission Network Service Provider (TNSP) responsible for planning and directing augmentations to the Victorian Declared Shared Network (DSN).

This PSCR represents stage one of the consultation process in relation to the limitation on New South Wales export into Victoria during peak demand periods.

This PSCR:

- Describes the need that AEMO is seeking to address and the assumptions used in identifying this need.
- Describes the credible options that AEMO currently considers may address the identified need.
- Discusses specific categories of market benefit which, in the case of this specific RIT-T assessment, are unlikely to be material.
- Identifies the preferred option and the reasons why AEMO considers this RIT-T application to be exempt from producing a Project Assessment Draft Report (PADR).

1.1 Submissions

AEMO invites written submissions on this Project Specification Consultation Report from registered participants and interested parties. Submissions are particularly sought on the preferred option presented and issues addressed in this report.

Submissions are due on or before 16 March 2012.

Submissions should be emailed to Planning@aemo.com.au.

Submissions will be published on the AEMO website. If you do not want your submission to be publicly available please clearly stipulate this at the time of lodgement.

The second and final stage of the RIT-T process, publication of the Project Assessment Conclusions Report (PACR), is expected by the end of April 2012.

Further details in relation to this project can be obtained from:

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2 Identified Need

2.1 Background

The New South Wales to Victoria interconnector comprises the 330 kV lines between Murray and Upper Tumut, Murray and Lower Tumut, Jindera and Wodonga and the 220 kV line between Buronga and Red Cliffs.

Transfer from New South Wales to Victoria is mainly limited by voltage collapse for loss of the largest Victorian generator or the thermal limits on the Murray-Dederang 330 kV or Wagga-Lower Tumut 330 kV lines.

AEMO currently procures a network loading control ancillary service (NLCAS) on the Murray-Dederang 330 kV lines which allows for greater use of inter-regional network capabilities between New South Wales and Victoria.[1]

The contracted NLCAS enables up to 350 MW of load to be shed following a credible contingency to reduce the flow on the Murray-Dederang line to within secure limits.[2] Without this NLCAS, pre-contingent flows would need to be limited to ensure that more conservative short-term ratings are not exceeded and a supply shortfall could arise leading to involuntary load shedding.

The contracted NLCAS is enabled when one of the following occur:

- Victoria is in a Lack of Reserve (LOR2) condition and transfer on the Murray-Dederang 330 kV line is at risk of being limited by its short-term rating.[3]
- AEMO Operations identifies opportunities for reducing the spot price differentials between New South Wales and Victoria.

In April 2011, the Australian Energy Market Commission (AEMC) amended the arrangements for the identification and procurement of network support and control ancillary services (NSCAS). These changes will take effect in April 2012.

From 2012, transmission network services providers (TNSPs) will be required to consider the NSCAS gaps identified by AEMO, and act to meet them through their network planning and investment processes.[4]

AEMO's 2010 and 2011 National Transmission Network Development Plan (NTNDP) identified an ongoing NLCAS requirement of approximately 260 MW to increase power transfers from New South Wales to Victoria over the Murray-Dederang 330 kV line by approximately 300 MVA.[5]

The existing NLCAS contract expires in July 2012, and AEMO is undertaking this RIT-T application to assess the market benefits from increasing power transfer capability from New South Wales to Victoria from summer 2012–13 onwards.

This RIT-T application is the first stage in an ongoing process to assess market benefits from increasing power transfer capability between New South Wales and Victoria, focusing on the benefits to be gained in the short-term after the discontinuation of the NLCAS scheme. For this reason the credible options in this RIT-T have been limited to those that can be implemented within one or two years. AEMO will continue to assess options with longer implementation timeframes as part of its normal planning processes.

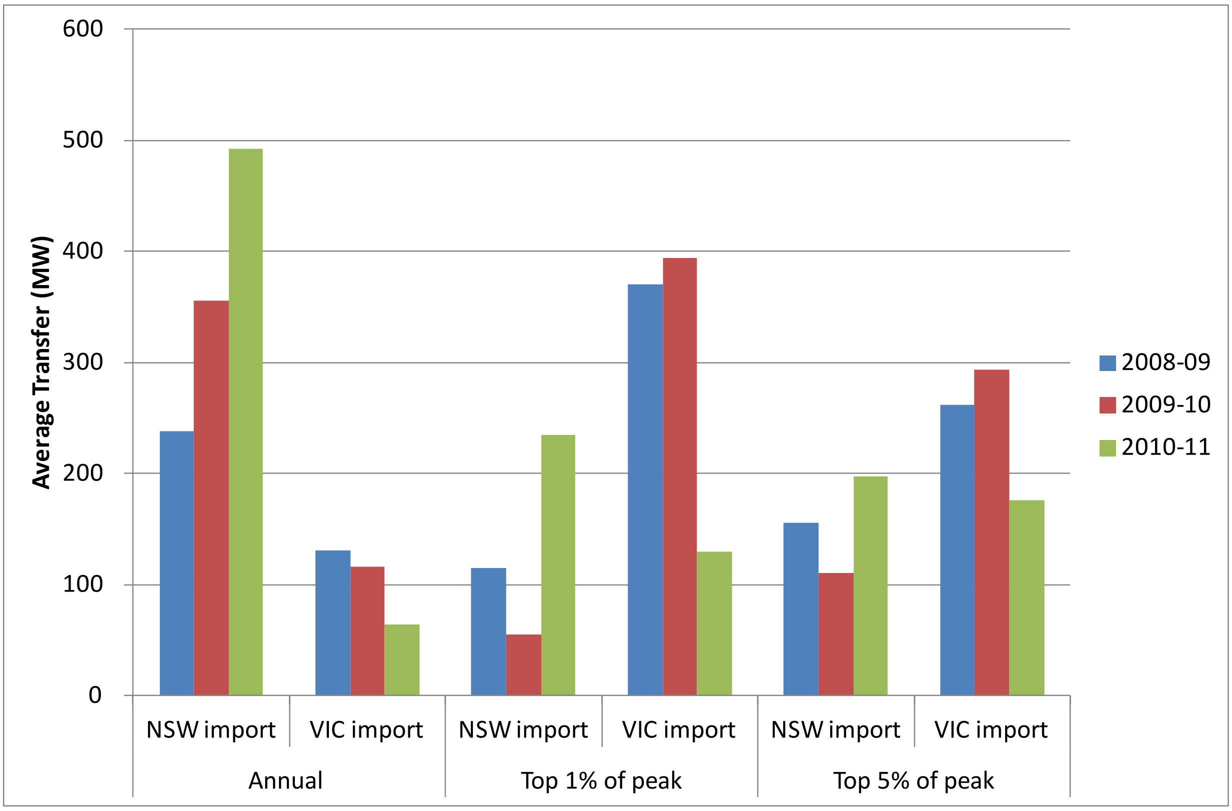
1 NLCAS is the capability of reducing an active power flow from a transmission network in order to keep the electrical current loading on interconnector transmission elements within their respective ratings following a credible contingency event in a transmission network.
2 A credible contingency event is defined in the NER as an event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope.
3 Lack of reserve level 2 (LOR2) - when the available reserve in a region is forecast to be less than the largest generation loss due to a credible contingency event in that region.
4 For more information about the new NSCAS Rules, see the National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011 No.2.
5 http://www.aemo.com.au/planning/2010ntndp_cd/home.htm

2.2 Description of the identified need

The 'identified need' for the proposed investment is an increase in the sum of producer and consumer surplus, i.e. an increase in net market benefit. AEMO believes that increasing the transfer capability from New South Wales to Victoria during peak demand periods will achieve this by decreasing the involuntary load shedding required in Victoria in those periods.

New South Wales is a net importer of energy over the New South Wales to Victoria interconnector. Victoria tends to import on the interconnector only at times of peak demand when regional supply capacity is stretched. Figure 1 shows the average export and import on the interconnector annually, and for the hours experiencing the top 1% and top 5% of Victorian regional demand, from 2008-09 to 2010-11.

Figure 1 – Average transfer on New South Wales to Victoria interconnector (MW)



AEMO's 2010 Constraint Report showed the power transfer capability from New South Wales to Victoria was constrained by:[6]

- A voltage stability limit for loss of the largest Victorian generator for 63 hours in 2009 and 94 hours in 2010.
- The thermal capability of the Murray-Dederang 330 kV line for 12 hours in 2009 and 73 hours in 2010.

The thermal capability of the Murray-Dederang 330 kV line decreases as the temperature increases. During periods of high temperatures, and hence high demand, this thermal limit constrains the transfer capability from New South Wales to Victoria to a greater extent than the voltage stability limit. Increasing the thermal capacity of the Murray-Dederang 330 kV line will therefore enable greater New South Wales to Victoria transfer during high demand periods.

This will then result in an increase in market benefits, in particular involuntary unserved energy, as discussed in more detail below.

[6] AEMO. "The Constraint Report 2010". Available from http://wwww.aemo.com.au/electricityops/0200-0006.html. Viewed 22 November 2011.

2.2.1 Market benefits

The purpose of the RIT-T is to identify the credible option that maximises the present value of net benefit to all those that produce, consume and transport electricity in the market.[7]

To measure the increase in net market benefit, AEMO will analyse the classes of market benefit required for consideration under the RIT-T, as set out in subparagraph 5 of the RIT-T.[8]

AEMO believes that the classes of market benefit most likely to change as a result of reducing the limitations on the Murray-Dederang 330 kV line are:

- **Changes in involuntary load shedding**

During periods of high demand in Victoria the increase in available supply from New South Wales will reduce the potential for supply shortages and consequent risk of involuntary load shedding in Victoria.

- **Changes in voluntary load curtailment**

A demand management non-network option may lead to an increase in the amount of voluntary load curtailment (and a decrease in involuntary load shedding).

The market benefits that are not material to this RIT-T assessment are discussed in Section 5.

2.2.2 Assumptions made in relation to the identified need

The following key assumptions drive the market benefits expected from reducing the limitations on the Murray-Dederang 330 kV line are:

- Demand diversity between Victoria and New South Wales.
- Victorian load duration characteristics.
- Forecast supply and demand balance.
- Value of customer reliability (VCR).
- Generator unit outage rates.

Demand diversity

Victoria and New South Wales tend to exhibit demand diversity – they experience their regional maximum demands at different times enabling capacity sharing between the regions at times of peak demand. Table 1 illustrates the demand diversity between Victoria and New South Wales. For example, at the time of Victoria's maximum demand (MD) in 2008-09, New South Wales demand was 87% of, or 1,848 MW less, than the maximum demand New South Wales experienced in that year.

Table 1 – Victoria and New South Wales (NSW) demand diversity

Year	Time of Victoria MD		Top 10 Victorian demand periods[9]	
	Percentage of NSW MD	Reduction from NSW MD (MW)	Percentage of NSW MD	Reduction from NSW MD (MW)
2008-09	87%	1,848	88%	1,738
2009-10	85%	2,094	83%	2,333
2010-11	93%	1,083	91%	1,355

[7] NER clause 5.6.5B (b)
[8] NER 5.6.5B(c)(4); and AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 5, page 4.
[9] Averaged over the half-hour trading periods which experienced the 10 highest demands for the year

Characteristics of the load profile

Victorian is a summer peaking region, with the highest demands in Victoria occurring during summer, generally on hot afternoons due to increased air conditioner load.

Figure 2 presents the load duration curve for the 2010–11 year. The figure shows a very sharp peak of short duration and average to low demand for most of the year. For more than 90% of the year, demands are less than 75% of the maximum demand experienced (equating to a reduction of approximately 2,500 MW from the maximum demand).

Figure 2 – Victorian load duration curve

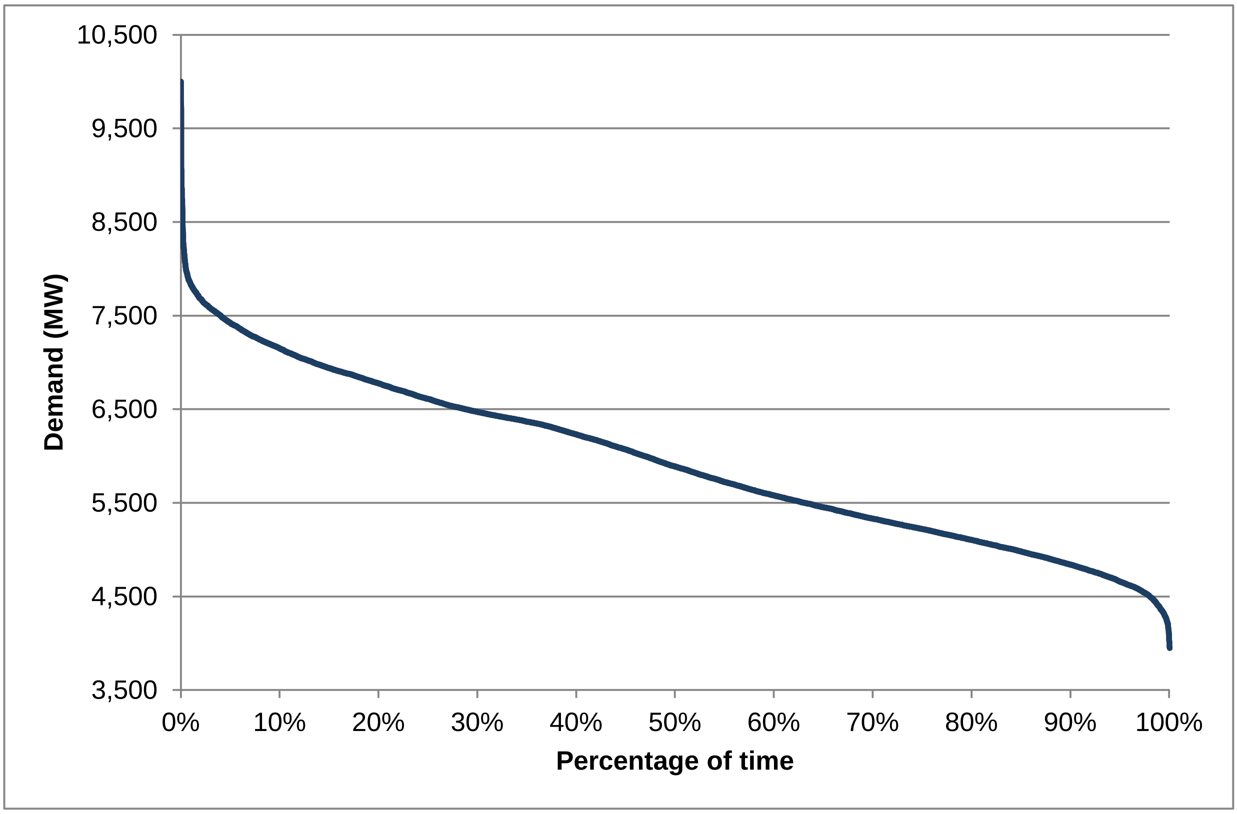
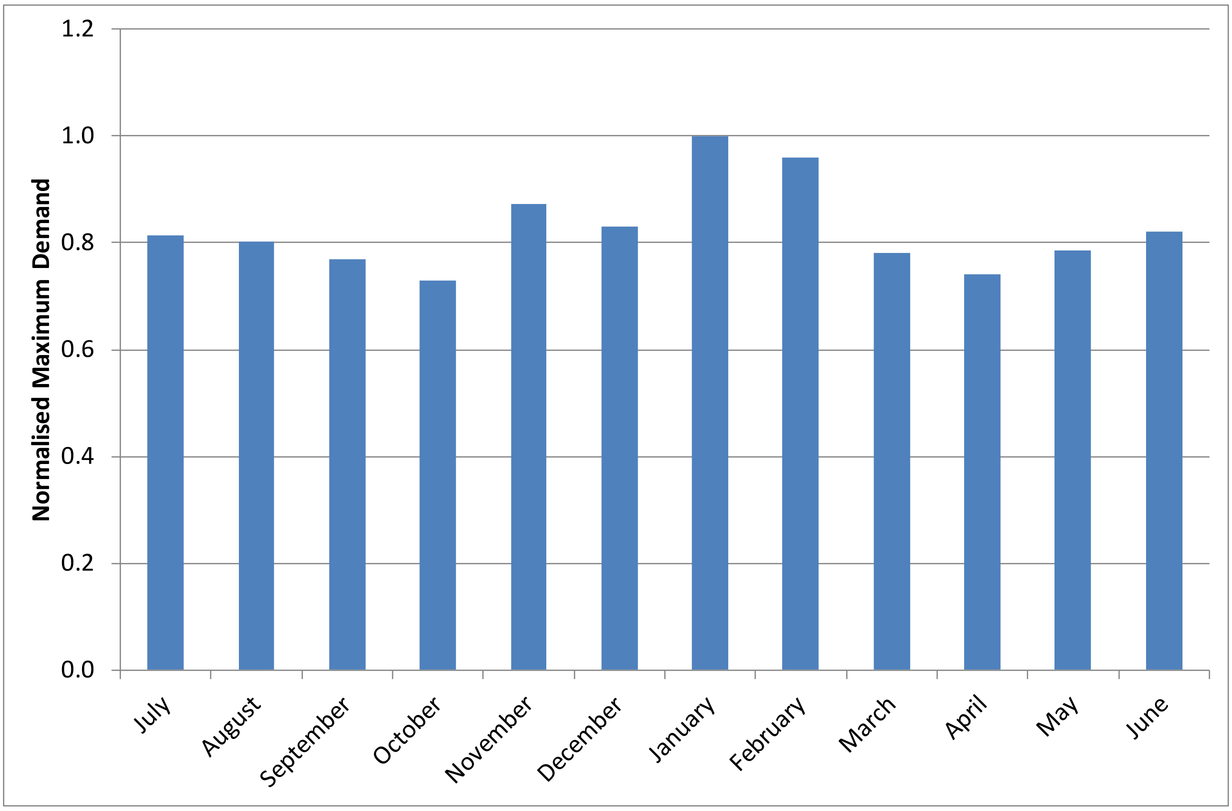


Figure 3 shows the normalised monthly maximum demand for Victoria, averaged over the three years from 2008–09 to 2010–11. This shows that the peak demand for the year generally occurs in January or February. Demands are also high in November and December.

Figure 3 – Victorian monthly maximum demand



Forecast supply and demand balance

The impact of the limitation on the Murray-Dederang line has been assessed under the 2010 National Transmission Network Development Plan's Decentralised World scenario, combined with a low carbon price trajectory (DW-L).[10]

This scenario assumes medium economic growth, with Victorian summer 10% probability of exceedance (POE) and 50% POE demands forecast to increase over the next 10 years at annual average rates of 2.2% and 2.1% respectively.[11]

Investment in new generation in the DW-L scenario (***scenario 1***) is modelled by a least-cost algorithm that minimises overall capital and operating costs subject to meeting predefined minimum reserve levels (MRLs).[12]

The limitation has also been assessed under a second scenario (***scenario 2***) with only committed new entry and retirements included until 2015-16, with delayed new entry from the DW-L scenario starting from 2016–17.[13]

Both scenarios assume that the committed Macarthur wind farm (420 MW) is in service from 2012-13. The additional new generation development and retirements modelled in Victoria in the two scenarios are shown in Table 2.

[10] AEMO. "2010 National Transmission Network Development Plan". Available at http://www.aemo.com.au/planning/ntndp.html. Viewed 22 November 2011.
[11] AEMO. "2011 Electricity Statement of Opportunities".Available at http://www.aemo.com.au/planning/esoo2011.html. Viewed 22 November 2011.
[12] See 2010 NTNDP for more information on the least cost modelling algorithm.
[13] Committed new entry and retirement from 2011 Electricity Statement of Opportunities.

Table 2 – Victoria – new entry generation and retirements modelled

Year	Scenario 1			Scenario 2
	Wind	OCGT	Coal	Wind
2012–13	0	0	0	0
2013–14	100	0	0	0
2014–15	300	0	0	0
2015–16	800	0	0	0
2016–17	900	600	-400	100
2017–18	1200	1500	-800	300

Figure 1 shows the projected Victorian supply-demand balance at the time of summer peak demand in Victoria until 2020-21, assuming the Scenario 1 pattern of generation investment.

The capacity for reliability shown represents the capacity required to meet the forecast minimum reserve level (based on the 10% POE demand forecast). The allocated installed capacity assumes a wind farm contribution factor of 7.7%[14] (available capacity time of peak) and existing interconnector limits.

The figure indicates that the allocated installed capacity in Victoria is close to the Victorian minimum reserve requirements across the forecast period.

Figure 4 provides the New South Wales supply-demand balance, also at the time of Victorian summer maximum demand. In New South Wales, the allocated installed capacity is consistently higher than the local reserve requirements, and therefore additional unused capacity may be available to support Victoria across the interconnector.

[14] Wind farm contribution factors from 2011 Electricity Statement of Opportunities.

Figure 4 – Victoria supply-demand balance (Scenario 1)

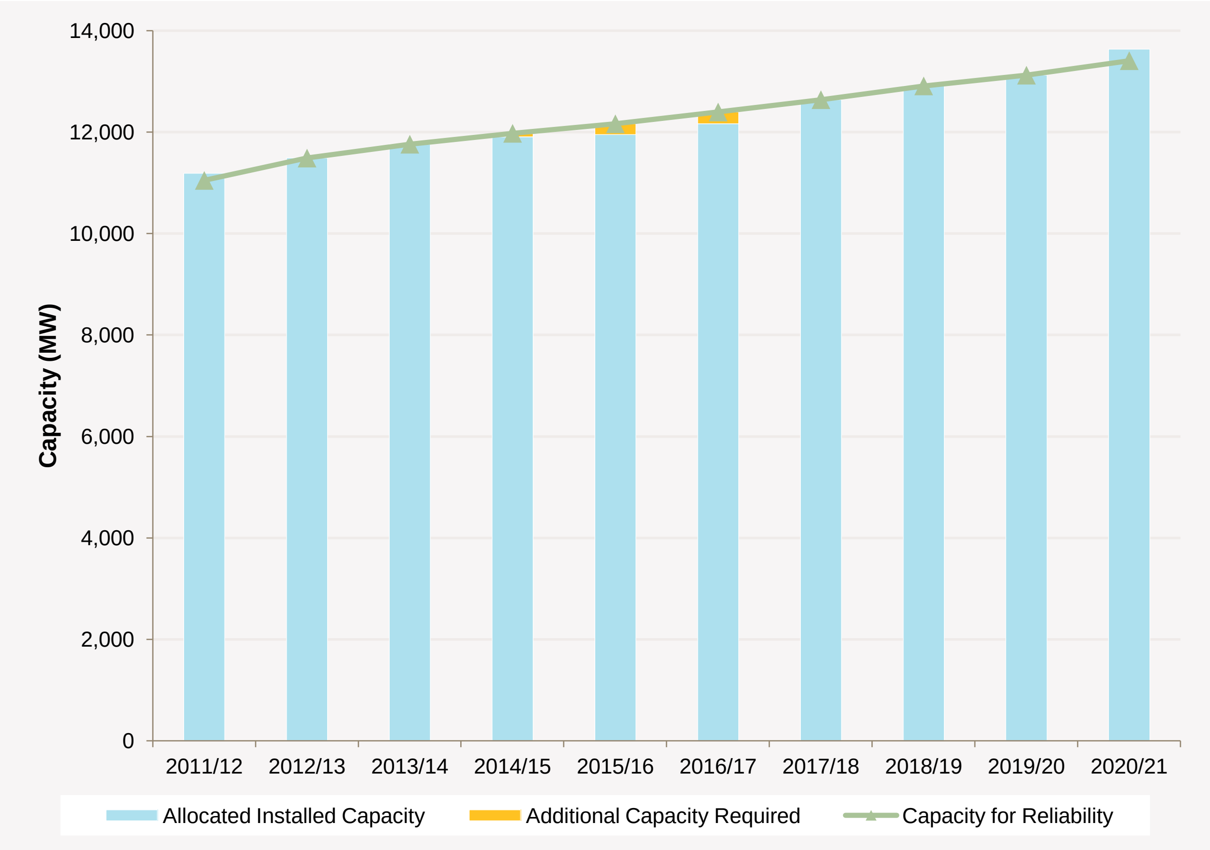


Figure 5 – New South Wales supply-demand balance (Scenario 1)

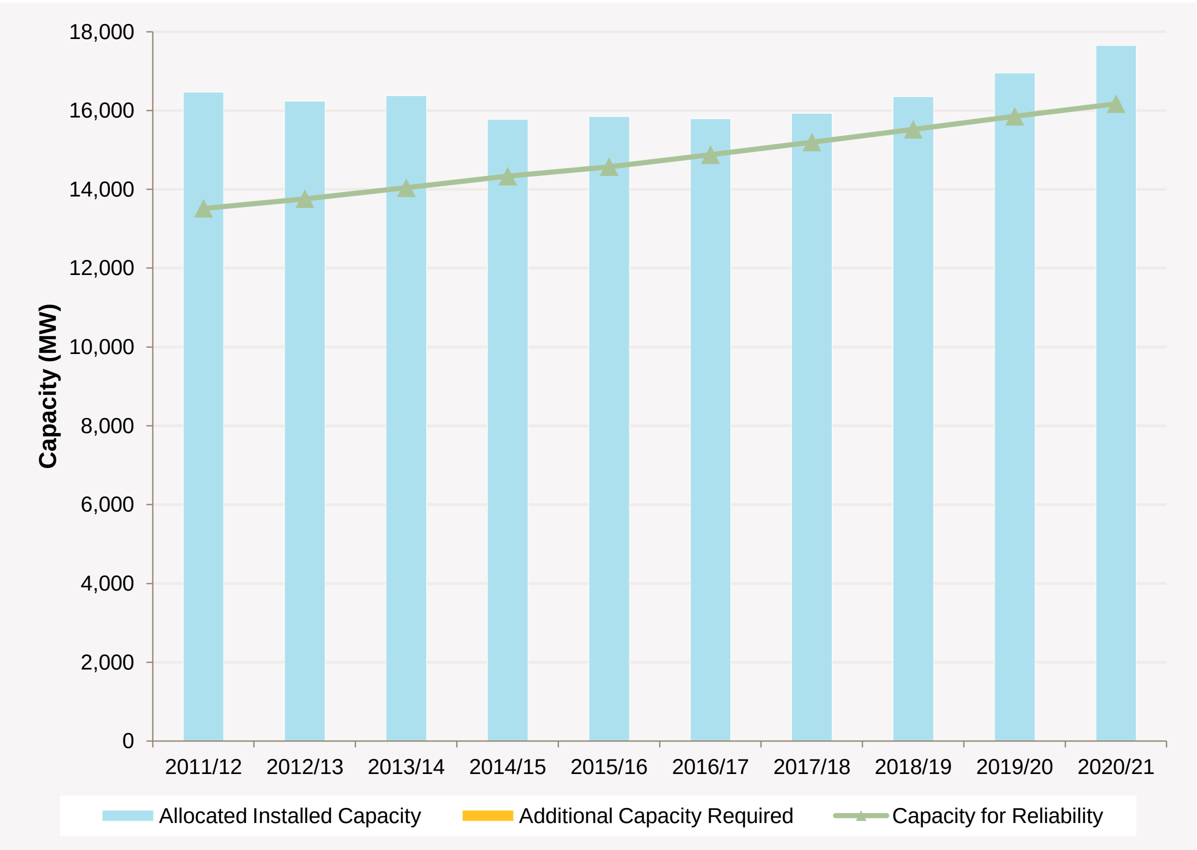
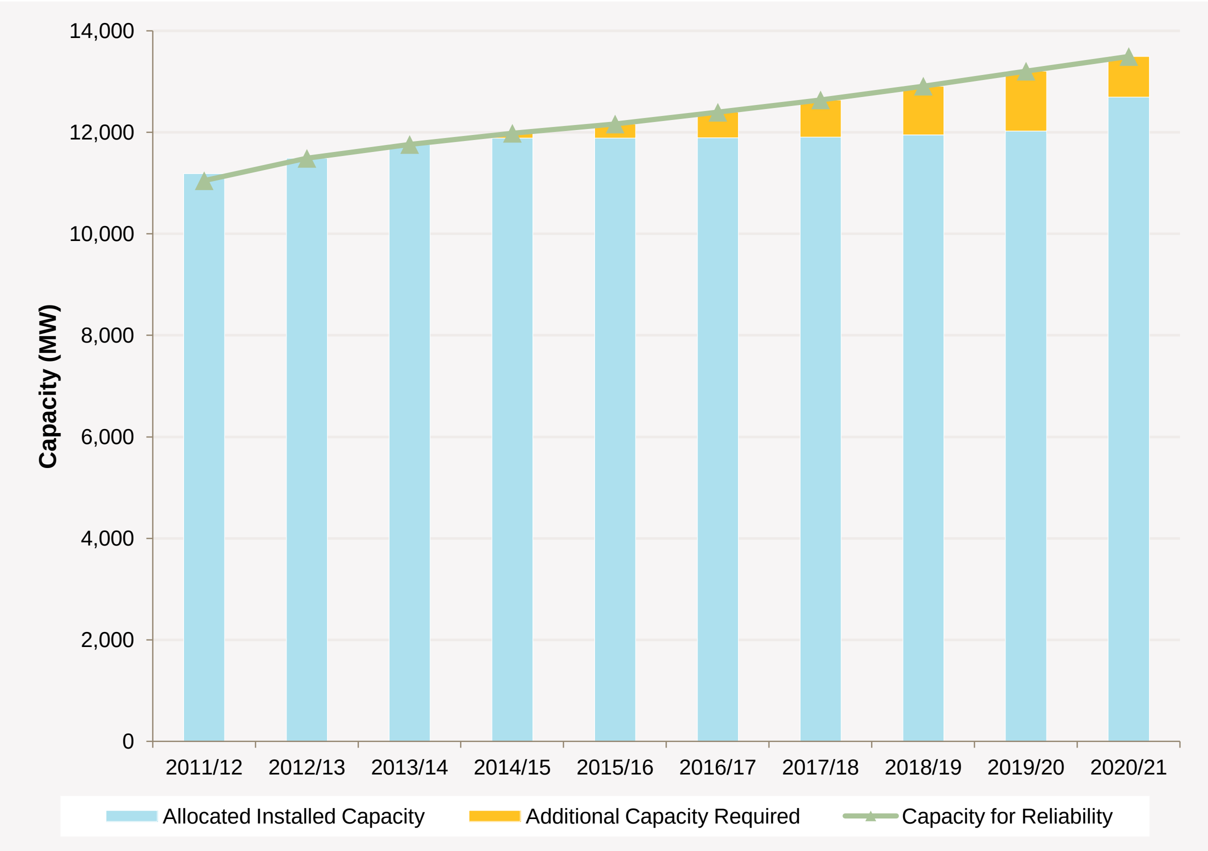


Figure 6 shows the Victorian supply-demand balance at time of Victorian summer peak under Scenario 2 assuming existing interconnector limits. Victoria experiences a shortfall in supply from 2015–16 under this scenario.

Figure 6 – Victoria supply-demand balance (Scenario 2)



Value of customer reliability

The cost of unserved energy is calculated using the value of customer reliability (VCR), which is an estimate of the value electricity consumers place on a reliable electricity supply. This value is equivalent to the cost to consumers of having their electricity supply interrupted for a short time.

Regional VCR values used by AEMO to calculate the cost of expected unserved energy are shown in Table 3.

Table 3 – Regional VCR values ($/MWh in 2011-12 Australian dollars)

Queensland	New South Wales	Victoria	South Australia	Tasmania
44,040	40,865	57,877	45,699	52,696

Generator unit outage rates

A significant amount of the limitation's expected cost may be attributed to rare occasions, where multiple generator outages coincide with high demand. To capture these rare occasions a monte-carlo algorithm is used to model a number of different random outage patterns to ensure that the overall outcome reflects a broad set of generation availability conditions. The modelling runs used to calculate the impact of the limitation are based on 200 monte-carlo simulations.

The generator unit outage rates used for this RIT-T, shown in Table 4, are assumed to vary based on generator technology and are based on results from AEMO's annual collection of generation data. Values are expressed as equivalent forced outage rates, meaning that include contributions from both full and partial outages. The values are consistent with those used in AEMO's 2010 NTNDP database.[15]

Table 4 – Equivalent forced outage rates (% of running hours)

Black coal	Brown coal	CCGT	OCGT	Gas other	Hydro
4.6%	4.6%	3.8%	25.4%	2.0%	4.1%

Demand side participation

The contribution of demand side participation (voluntary load curtailment) is modelled as a spot-price sensitive reduction in demand. The demand side participation assumptions align with those used in the 2010 NTNDP.

Discount rate

To compare cash flows of options with different time profiles, it is necessary to use a discount rate to convert the future cash payments and receipts into present value terms. The choice of discount rate will affect the estimated present value of costs and benefits and may, in turn, affect the ranking of alternative options.

Subparagraph 14 of the RIT-T test requires that any present value calculations be carried out using a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.

A real pre-tax discount rate of 10% has been applied for the purposes of this analysis.

For the purposes of sensitivity testing, a lower bound real pre-tax discount rate of 6%[16] and an upper bound real pre-tax discount rate of 12% have been applied.

2.2.3 Expected impact of the limitation

The expected impact of the limitation has been calculated by comparing results of an unaugmented case with a case that approximates the full removal of the limitation (a 325 MW increase in the Murray-Dederang capability enabled during low reserve conditions).

The difference between these two cases represents the expected market costs due to the original limitation. These market impacts are presented in Table 5 (Scenario 1), and Table 6 (Scenario 2).

The tables show:

- Load at risk, which is the maximum megawatt (MW) load shedding forecast to occur across the monte-carlo simulations.
- Energy at risk, which is the maximum annual energy shed across the monte-carlo simulations.
- Expected unserved energy, which is the portion of the energy at risk after taking into account the probabilities of the 10% POE and 50% POE demand forecasts[17] and the monte-carlo forced generator outages.
- Limitation cost of unserved energy, which is the expected market cost due to unserved energy in Victoria and South Australia.
- Total limitation cost, which is the expected total of all considered market costs.

[15] http://www.aemo.com.au/planning/2010ntndp_cd/html/NTNDPdatabase.htm
[16] The regulated cost of capital is used as the lower boundary, consistent with subparagraph 15 of the RIT-T
[17] Uncertainty in the demand forecasts are accounted for by applying a 10% POE demand forecast and a 50% POE demand forecast and weighting them 30% and 70% respectively to calculate the expected unserved energy.

- In this study, the assessment of market costs (and potential market benefits) are limited to those resulting from reduced network congestion, and include:
  - generation dispatch costs, including fuel, maintenance and operating costs
  - the quantity of unmet load valued at regional VCRs, and
  - the contribution and costs of voluntary load curtailment.

Table 5 – Forecast market impact (Scenario 1)

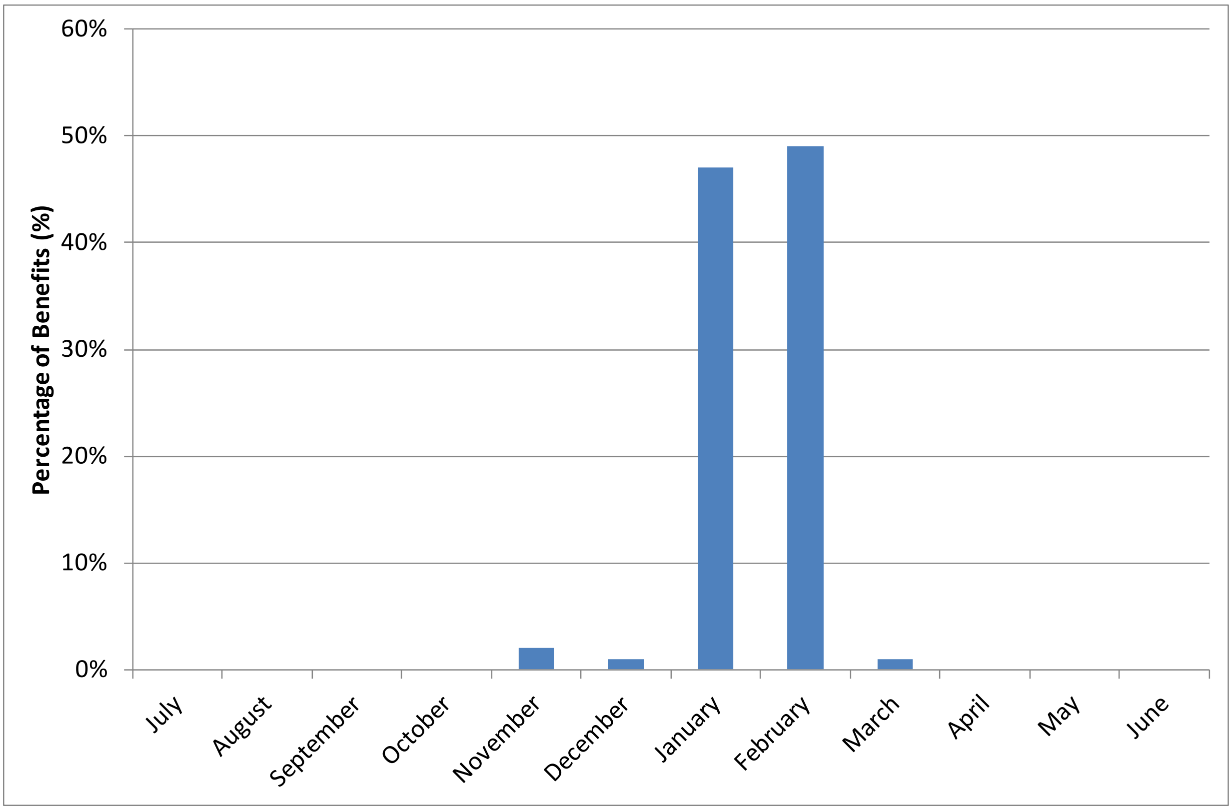
Year	Load at risk (MW)	Energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost of unserved energy ($ million)	Total limitation cost ($ million)
2012–13	13	399	17	1.0	1.2
2013–14	33	552	47	2.5	2.8
2014–15	13	713	33	1.8	2.1
2015–16	23	493	45	2.6	2.9
2016–17	30	450	46	2.6	2.9
2017–18	11	214	18	1.0	1.1

Table 6 – Forecast market impact (Scenario 2)

Year	Load at risk (MW)	Energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost of unserved energy ($ million)	Total limitation cost ($ million)
2012–13	13	399	18	1.0	1.2
2013–14	34	664	44	2.4	2.8
2014–15	33	848	90	4.9	5.4
2015–16	48	1,237	148	8.1	8.7
2016–17	31	783	176	9.8	10.4
2017–18	29	693	180	10.2	11.0

Figure 7 shows the average percentage of benefits that occur in each month (average over all years and scenarios) This shows that benefits only accrue in the months from November to March with the vast majority of benefits accruing in January and February.

Figure 7 – Monthly market benefits



3 Potential credible options to address the identified need

As defined by clause 5.6.5D of the NER, a credible option is an option that:

- addresses the identified need,
- is commercially and technically feasible, and
- can be implemented in sufficient time to meet the identified need.

For this RIT-T, the identified need is an increase in market benefits arising from a decrease in involuntary load shedding during peak demand times in Victoria. Any option which increases the transfer capability from New South Wales to Victoria will address this identified need. Table 5 and Table 6 showed that an increase in market benefits is possible from summer 2012/13 onwards.

The estimated implementation timeframe required for a network option is three to six years, depending on the option. For this reason the credible options under this RIT-T have been constrained to those options which can be implemented by summer 2012–13 and which will be available for a period of three to six years.

AEMO will separately assess network and non-network options to address the identified need in the longer term in detail as appropriate.

3.1 Non-network demand management option

A non-network demand management option could be implemented in a relatively short timeframe, and could lead to net market benefits by decreasing involuntary unserved load. For this RIT-T, two alternative modes of operation for the demand management option have been identified.

Option 1: Post-contingent load reduction control scheme

The power system is in a secure operating state (NER 4.2.4) if it is operating within its secure technical envelope, i.e. the power system can withstand a credible contingency without a widespread failure. A control scheme that reduces load directly after a contingency allows a greater amount of flow pre-contingent whilst the system remains in a secure operating state.

A non-network option to reduce around 350 MW of load in Victoria within 5-seconds of a Murray-Dederang contingency will allow the line to be operated up to its 5-minute rating pre-contingent, increasing the transfer capability on these lines by approximately 300 MW.

The non-network option would be enabled when the flow on the Murray-Dederang line is at risk of being limited by its 15-minute rating and when low reserve is forecast in Victoria (LOR2 condition forecast). The modelled expected number of hours this would occur is shown in Section 3.3, however the hours required could be more or less depending on conditions.

Load reduction would be required only after a Murray-Dederang contingency during the LOR2 periods. Historical information suggests that the Murray-Dederang lines will be unavailable for approximately 4.47 hours annually due to unplanned outages, equating to a forced outage rate of 0.05%.

Option 2: Demand side response

A non-network option to reduce load in Victoria during peak demand periods could also lead to market benefits, if the cost of that load reduction is less than the VCR ($57,877/MWh). A demand side response option would need to reduce load during system normal conditions.[18] whenever low reserve is forecast in Victoria

The modelled expected number of hours this would occur is shown in is shown in Section 3.3, however the hours required could be more or less depending on conditions.

3.2 Material interregional impact

In accordance with NER 5.6.6(c)(6)(ii), AEMO has considered whether any of the credible options above are expected to have a material interregional impact. AEMO considers this to be the same as a material inter-network impact, which is defined in the NER as:

A material impact on another Transmission Network Service Provider's network, which may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network.

The credible options are not expected to have a material impact on the interregional system compared with the existing operation of the system:

- Option 1 will have the same interregional impact as the current NLCAS scheme which has been in service since the commencement of the National Electricity Market (NEM).
- Option 2, demand side response in Victoria, is not expected to impact on the interregional system.

3.3 Required technical characteristics for a non-network option

This section describes the technical characteristics of the identified need that a non-network option would be required to deliver.

The simulated maximum, and expected number of hours, where enablement of a non-network option would be required is shown in Table 7 (Scenario 1) and Table 8 (Scenario 2) for both 10% POE and 50% POE conditions. The maximum enablement hours are the maximum

[18] System normal is the condition where all transmission network elements are in service.

annual hours across the monte-carlo simulations. The expected enablement hours are the average hours across the monte-carlo simulations.

These hours are forecast to occur between the months of November to March only.

Table 7 – Summary of modelled expected enablement hours (Scenario 1)

Year	10% POE		50% POE	
	Maximum enablement hours	Expected enablement hours	Maximum enablement hours	Expected enablement hours
2012–13	19	8	9	1
2013–14	24	12	12	2
2014–15	22	11	10	1
2015–16	20	10	7	1
2016–17	20	12	9	1
2017–18	14	4	13	3

Table 8 – Summary of modelled expected enablement hours (Scenario 2)

Year	10% POE		50% POE	
	Maximum enablement hours	Expected enablement hours	Maximum enablement hours	Expected enablement hours
2012–13	19	8	9	1
2013–14	24	13	12	3
2014–15	33	18	14	4
2015–16	36	22	20	7
2016–17	50	28	28	13
2017–18	39	26	33	17

A post-contingent load reduction control scheme (Option 1) would expect to be enabled for the number of hours shown in the tables above, and only be required to shed load when a unplanned outage of the Murray-Dederang lines occurs.

Historical information suggests that the Murray-Dederang lines will be unavailable for approximately 4.47 hours annually on average due to unplanned outages, equating to an outage rate of 0.05%. The expected hours a post-contingent load reduction control scheme (Option 1) would therefore be expected to shed load for is just 0.05% of the time the scheme is enabled.

A pre-contingent demand side response scheme (Option 2) would be expected to shed load for the number of hours shown in the tables above.

The performance requirements of a non-network option are shown in Table 9.

A post-contingent load reduction control scheme (Option 1) would be required to make available around 350 MW of load reduction in preparation for a Murray-Dederang contingency. A pre-contingent demand side response scheme (Option 2) would be required to make available around 50 MW of load reduction in preparation for the low reserve condition.

Table 9 – Performance requirements of a non-network option

Performance requirement	Contracted level of performance
Load shedding control range – post-contingent	350 MW
Load shedding control range – pre-contingent	50 MW
Maximum time to enable service	Less than 1 minute
Load shedding response time	Less than 5 seconds

3.4 Information to be provided by proponents of a non-network option

Proponents of non-network options are invited to lodge a submission to AEMO, as indicated in Section 1.1 of this report, and should include the following details:

- Proponent name and contact details.
- A detailed description of the proposal.
- A nominated site.
- The capacity to be provided.
- A commissioning date with contingency specified.
- Availability and reliability performance benchmarks.
- Proposed contract period.

All proposals must satisfy the requirements of any applicable laws and the requirements of any relevant regulatory authority.

Any network reinforcement costs required to accommodate the non-network solution will typically be borne by the proponent(s) of the non-network options. For example, some non-network alternatives such as embedded generation may require fault level mitigation measures; and any associated costs would be borne by proponents.

4 Options considered but not progressed

The following options were considered but have not been included as credible options for the purpose of this RIT-T.

4.1 Non-network option – Generation reduction control scheme

A non-network option to reduce generation on the Murray-side of the Murray-Dederang 330 kV line within 5-seconds of a Murray-Dederang contingency was considered. However to ensure that loading on the remaining circuit is reduced to secure levels after a contingency, it would be necessary to couple this scheme with a load reduction scheme on the Dederang side of the line.

To balance supply and demand after the contingency (and the control's scheme reduction of generation), either load would need to reduce or generation would need to increase. Any increase in New South Wales generation will overload the remaining Murray-Dederang circuit and it is unlikely that additional generation will be available in Victoria due to the low reserve condition necessary for the scheme's enabling.

Therefore it is likely that post-contingent load reduction would be required within 5-seconds of the contingency. This would either need to be enabled as a post-contingent load reduction control scheme (Option 1) or as pre-contingent load reduction (Option 2).

AEMO is therefore not proposing to include this option as part of this RIT-T assessment.

4.2 Non-network option – Additional generation in Victoria

New generation investment in Victoria could assist to meet peak demand and may result in a reduction in involuntary load shedding.

Expected generation developments in Victoria and in the wider NEM have been included as part of the reasonable scenarios adopted in conducting the RIT-T analysis (see section 2.2.2). AEMO does not intent to consider options involving additional generation as an alternative in the RIT-T assessment itself.

4.3 Network options

Various network options to increase the transfer capacity between New South Wales and Victoria were considered, including:

- A third 330 kV, circuit from Murray to Dederang at an indicative cost of $170 million (excluding easement cost). The lead time of this option is 5 years, subject to obtaining the necessary easement.
- A second 330 kV circuit from Dederang to Jindera at an indicative cost of $115 million (excluding easement cost). The lead time of this option is 5 years, subject to obtaining the necessary easement.
- A New South Wales to Victoria interconnection upgrade at an indicative cost of $200 million involving:
  - installation of a fourth 330/220 kV Dederang transformer and a third 700 MVA 330/220 kV South Morang transformer
  - phase angle regulator on the Jindera-Wodonga 330 kV circuit
  - up-rating of the 220 kV Eildon-Thomastown and 330 kV South Morang-Dederang circuits
  - cut-in of the 220 kV Rowville-Thomastown circuit at South Morang, and

  - series capacitors on the Eildon-Thomastown 220 kV and Wodonga-Dederang 330 kV circuits.
- A segment of the conceptual NEMLink project presented in AEMO's 2010 NTNDP with an indicative cost of $470 million (present value) and involving:
  - connection to the existing Victoria 500 kV network at the Sydenham 500 kV/220 kV substation
  - connection to the NSW 500 kV network at Bannaby and Sydney
  - a new 500/220 kV substation at Bendigo with 3x 1000 MVA 500/275 kV transformers
  - a new 500/330 kV substation at Wagga with 3x 1000 MVA 500/330 kV transformers
  - 500 kV AC double circuit lines (quad Orange) from Sydenham to Bendigo, Bendigo to Wagga, Wagga to Bannaby and from Bannaby to Sydney
  - 500 kV series compensation, with compensation degrees ranging from 50-70% as required to allow the NEMLink backbone to be loaded up to 3000 MVA, and
  - Shunt reactive power compensation devices in the form of fixed line connected shunt reactors (100 MVAr – 150 MVAr) and bus connected SVCs (400 MVAr – 500 MVAr) for switching voltage and system voltage control.

The AER RIT-T Guidelines note that as a general rule an option is likely to be economically feasible where its estimated costs are comparable to other credible options which address the identified need[19]. The exception is where it is expected that an option with higher costs is also likely to deliver materially higher market benefits.

Network options of this scale would be expected to have materially higher market benefits than the non-network options considered as credible options in this RIT-T, including benefits arising from:

- Changes in generator fuel consumption arising through different patterns of generation dispatch (including changes in carbon costs).
- Changes in costs for parties, other than the Transmission Network Service Provider (TNSP), due to:
  - differences in the timing of new plant
  - differences in capital costs
  - differences in operational and maintenance costs.
- Differences in the timing of transmission investment.
- Changes in network losses.
- Changes in ancillary services costs.
- Competition benefits.
- Any additional option value.
- The negative of any penalty paid or payable for not meeting the LRET.

However all these network options would require at least three to six years to implement, when market benefits are available from 2012–13 (see Table 5). AEMO is therefore not proposing to include any network options as part of this RIT-T assessment.

However AEMO intends to undertake further studies as appropriate to assess the benefits of network options in more detail.

[19] AER. "Final Regulatory Investment Test for Transmission Application Guidelines", Available at http://www.aer.gov.au/content/index.phtml/itemId/730920. Viewed 22 November 2011.

5 Materiality of market benefits

AEMO notes the NER requirement that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that:

- a specific class (or classes) of market benefit are unlikely to be material in relation to the RIT-T assessment for a specific option, or
- the cost of undertaking the analysis to quantify that benefit would likely be disproportionate to the “scale, size and potential benefits of each credible option being considered in the report”[20].

At this stage of the consultation, AEMO considers that the following classes of market benefits are not material for this RIT-T assessment in relation to the non-network demand management options:

- **Changes in fuel consumption arising through different patterns of generation dispatch**

The non-network demand management options are expected to lead to reductions in dispatch costs. Option 1, load reduction control scheme will enable increased transfer capacity from New South Wales to Victoria enabling the dispatch of lower cost generation in New South Wales (or Queensland) to displace the higher cost generation operating in Victoria to meet peak demand. Option 2, demand management, will reduce overall demand and hence the dispatch of high cost generation required to meet that demand.

However, these dispatch cost savings are estimated to be less than 5% of the benefits arising from reductions in voluntary and involuntary load reduction (demonstrated Table 10 and Table 11 of Section 6).

- **Changes in costs for parties, other than the TNSP**

There is no material expected change to the timing of new generation investment related to the non-network demand management options considered in this RIT-T due to the relatively short expected timeframe of operation of the options (between three to six years).

- **Differences in the timing of transmission investment**

There is no expected change to the timing of transmission investment other than the credible options directly related to the identified need. AEMO therefore does not propose to estimate any additional transmission investment market benefit for this RIT-T assessment.

- **Changes in network losses**

Changes in network losses due to the non-network demand management options are expected to be minor due to the small number of hours the options would be implemented.

- **Changes in ancillary services costs**

FCAS costs are typically less than one per cent of the electricity market. Further, the inclusion of all, or some, of the FCAS markets as part of the market modelling under the RIT-T would lead to substantial increase in the complexity and cost of the RIT-T assessment. Such increased complexity is not warranted given that changes in FCAS costs will not have a role in determining the preferred option.

- **Option value**

AEMO notes the AER’s view that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change

[20] NER 5.6.6(c)(6)(iii).

and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[21]

AEMO also notes the AER's view that appropriate identification of credible options and reasonable scenarios capture any option value, thereby meeting the NER requirement to consider option value as a class of market benefit under the RIT-T.

For this RIT-T assessment, the estimation of any option value benefit over and above that already captured via the scenario analysis in the RIT-T would require a significant modelling assessment, which would be disproportionate to any additional option value benefit that may be identified for this specific RIT-T assessment. AEMO therefore does not propose to estimate any additional option value market benefit for this RIT-T assessment.

- **Competition benefits**

Competition benefits due to the non-network demand management options are expected to be minor due to the small number of hours the options would be implemented. Both options would only be implemented during periods of peak demand in Victoria, when it is expected that spot market prices would be high and all available generation would be dispatched. Benefits from increased competition at these times, over and above those already identified under "changes in fuel consumption arising through different patterns of generation dispatch" would be minor.

Further, the inclusion of competition benefits as part of the market modelling under the RIT-T would lead to substantial increase in the complexity and cost of the RIT-T assessment. Such increased complexity is not warranted given that changes in competition benefits will not have a role in determining the preferred option.

[21] AER. "Final Regulatory Investment Test for Transmission Application Guidelines," Available http://www.aer.gov.au/content/index.phtml/itemId/730920. Viewed 22 November 2011.

6 Identification of preferred option

This section presents the potential market benefits of the non-network demand management options.

6.1 Market benefits under reasonable scenarios

Two reasonable scenarios were assessed:

- Scenario 1, medium economic demand growth with committed new entrant generation and additional new entrant generation assumed to meet minimum reliability levels (on a least cost basis).
- Scenario 2, medium economic demand growth with committed new entrant generation and uncommitted new entrant generation from Scenario 1 delayed for 3 years.

Table 10 and Table 11 show the annual estimated market benefits of an increase in Murray-Dederang ratings of 325 MW, weighted according to results under 10% POE and 50% POE demand conditions, for Scenario 1 and Scenario 2 respectively.

Annual market benefits are significantly higher under Scenario 2 where new generation investments are deferred until at least 2016/17. In Scenario 1, where generation investment and retirement proceed to meet minimum reserve levels, market benefits are expected to fluctuate between $1 and $3 million per annum.

Table 10 – Annual estimated market benefits for Scenario 1 ($ million)

Benefit Type	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Dispatch cost benefits	0.0	0.1	0.0	0.0	0.0	0.0
Involuntary load reduction benefits	1.0	2.5	1.8	2.6	2.6	1.0
Voluntary load curtailment Benefits	0.1	0.3	0.2	0.2	0.2	0.1
Total benefits	1.2	2.8	2.1	2.9	2.9	1.1

Table 11 – Annual estimated market benefits for Scenario 2 ($ million)

Benefit Type	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Dispatch cost benefits	0.1	0.1	0.1	0.0	0.1	0.0
Involuntary load reduction benefits	1.0	2.4	4.9	8.1	9.8	10.2
Voluntary load curtailment Benefits	0.1	0.3	0.4	0.5	0.6	0.8
Total benefits	1.2	2.8	5.4	8.7	10.4	11.0

6.2 Probability-weighted market benefits

Table 12 shows the probability-weighted market benefits, and the expected enablement hours of a non-network option, across the reasonable scenarios assuming each scenario has equal weighing.

This equates to an available present value of gross market benefits of $16.2 million over the period from 2012–13 to 2017-18, assuming a 10% discount rate.

Table 12 – Expected hours and market benefits available

Expected values	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Enablement hours	3	6	6	8	11	12
Total benefits ($ million)	1.0	2.5	3.3	5.4	6.2	5.6

6.3 Preferred option – Non-network demand management

The cost of the preferred option must be less than the benefits arising from the option, or in other words the preferred option must provide positive net benefit.

Non-network options of the type considered in this RIT-T would be expected to have costs associated with: availability, enablement and load reduction. The combination of these three costs would need to be less than the total benefits shown in Table 12.

To evaluate the potential net benefits of a potential non-network demand management options in this RIT-T, the cost structure shown in Table 13 has been assumed.

Note that this cost structure is an example only, and net market benefits may occur for a range of cost structures. AEMO will engage with potential providers of non-network options to develop the optimal solution to the identified need.

Table 13 – Example cost structure for non-network options

Cost category	Cost
Availability cost ($/annum)[22]	1,000,000
Enablement cost ($/hour)	50,000
Load shedding cost ($/MWh)	20,000

Table 14 shows the cost-benefit assessment for a post-contingent load reduction control scheme (Option 1). For this option load reduction is only required when a Murray-Dederang contingency occurs after the scheme is enabled. This has a 0.05% chance of occurring and it has been assumed that a load reduction of 350 MW is required to secure the system.

Table 14 – Cost-benefit example for Option 1

Cost-benefit	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Availability cost ($)	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Enablement cost ($)	155,000	275,000	305,000	380,000	545,000	575,000
Load shedding cost ($)	11,073	10,877	11,849	16,084	31,310	64,306
Cost of option ($)	1,166,073	1,285,877	1,316,849	1,396,084	1,576,310	1,639,306
Net benefit ($)	-156,073	1,184,123	2,028,151	3,978,916	4,598,690	3,925,694

Table 15 shows the cost-benefit assessment for a pre-contingent demand side response scheme (Option 2). For this option, load reduction is required when the scheme is enabled. The reduced load is the probability-weighted expected unserved energy from Scenario 1 (shown in Table 5) and Scenario 2 (shown in Table 6). For the purpose of this example, it is

[22] Availability assumed over the months of November to March only

assumed that this option does not have an enablement cost in addition to the load shedding cost.

Table 15 – Cost-benefit example for Option 2

Cost-benefit	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Availability cost ($)	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Load shedding required (MWh)	18	46	62	97	111	99
Load shedding cost ($)	350,000	910,000	1,230,000	1,930,000	2,220,000	1,980,000
Cost of option ($)	1,350,000	1,910,046	2,230,062	2,930,097	3,220,111	2,980,099
Net benefit ($)	-340,000	559,955	1,114,939	2,444,904	2,954,889	2,584,901

Table 16 shows the net present value of Option 1 and Option 2 using the assumed cost structure. Option 1 has a greater net benefit under all discount rate sensitivities than Option 2.

This result would be expected under a range of potential cost structures as the expected number of hours of load shedding required is significantly less under Option 1 than under Option 2.

Table 16 – Net present value of Option 1 and Option 2 ($)

Discount rate	Option 1	Option 2
12%	9.4	5.5
10%	10.1	6.0
6%	12.0	7.1

Table 16 shows that a non-network demand management option can provide positive net market benefits. The specific form of the demand management option implemented will be determined via the cost structures offered by proponents of potential solutions.

7 Exemption from preparing project assessment draft report

Under clause 5.6.6 (y) of the NER, TNPSs are exempt from providing a project assessment draft report (PADR) if all the following conditions are met:

- The estimated capital cost of the preferred option is less than $35 million.
- The TNSP has indentified the preferred option in its consultation report, the reasons for the preferred option and noted that it will be exempt from publishing the PADR.
- The preferred option and any other credible options do not have a material market benefit other than benefits associated with changes in voluntary load curtailment and involuntary load shedding.
- The TNSP forms the view that submissions on the consultation report did not identify any additional credible options that could deliver a material market benefit.

AEMO considers that the proposed investment is exempt from producing a PADR. The preferred option for addressing the identified need, as detailed in Section 6.3, is a non-network demand management option.

As the identified need is an increase in net market benefits, the cost of the preferred option must be less than the increase in net market benefits. The expected total increase in gross market benefits is $23.9 million over the period from 2012–13 to 2016–17 as shown in Table 12, and hence the cost of the option must be less than the $35 million threshold.

The preferred option does not have material market benefits other than those associated with changes in voluntary load curtailment and involuntary load shedding, as detailed in Section 6.

If AEMO receives submissions on this report that identify any additional credible options that could deliver a material market benefit then AEMO will publish a PADR as required.

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