VICTORIAN RELIABILITY SUPPORT – PROJECT ASSESSEMENT CONCLUSIONS 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 on 30 June 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 Assessment Conclusions Report (PACR) is the final 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.
- Shows 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 $17.4 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.
- Describes the assumptions and methodology used to quantify the market benefits of the credible options.
- Identifies the preferred option: a non-network demand management option with costs less than the expected gross market benefits.
- Summarises the consultation process undertaken on the preferred option.

The report recommends the implementation of a non-network demand management option by November 2012 for a period of up to 6 years at a cost less than the gross market benefits. AEMO will commence the tender process to allow potential service providers to tender their services in the second half of 2012.

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1 Introduction

This Project Assessment Conclusions Report (PACR) has been prepared by the Australian Energy Market Operator (AEMO) in accordance with the requirements of National Electricity Rules (NER) clause 5.6.6.

This PACR follows on from the Project Specification Consultation Report (PSCR) in relation to the limitation on New South Wales export into Victoria during peak demand periods.[1] The PSCR was published on 19 December 2011 and was open for consultation until 16 March 2012.

The PSCR included:

- A description of the identified need and the assumptions used in identifying the need.
- The credible options to address the identified need and the alternative investment options considered but not progressed.
- The specific categories of market benefit which, in the case of this specific RIT-T assessment, were considered unlikely to be material.
- Identified the preferred option and the reasons why AEMO considered this RIT-T application to be exempt from producing a Project Assessment Draft Report (PADR).

No submissions were received in response to the PSCR and this PACR represents the final stage of this RIT-T application.

This PACR:

- Describes the methodology used to quantify each class of material market benefit for each credible option, and provides the reasons why AEMO has determined specific categories of market benefits are immaterial.
- Shows a quantification of the costs and classes of material market benefit for each credible option and the results of a net present value analysis of each credible option.
- Identifies the preferred investment option and details the technical characteristics and estimated implementation date of the option.
- Summarises the results of consultation process undertaken on the preferred investment option.
- Recommends the action to be undertaken.

[1] AEMO. "Victorian Reliability Support – Project Specification Consultation Report". Available from http://www.aemo.com.au/planning/rit-ts.html

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.[2]

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.[3] 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 occurs:

- 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.[4]
- 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.[5]

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.[6]

The existing NLCAS contract expires on 30 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.

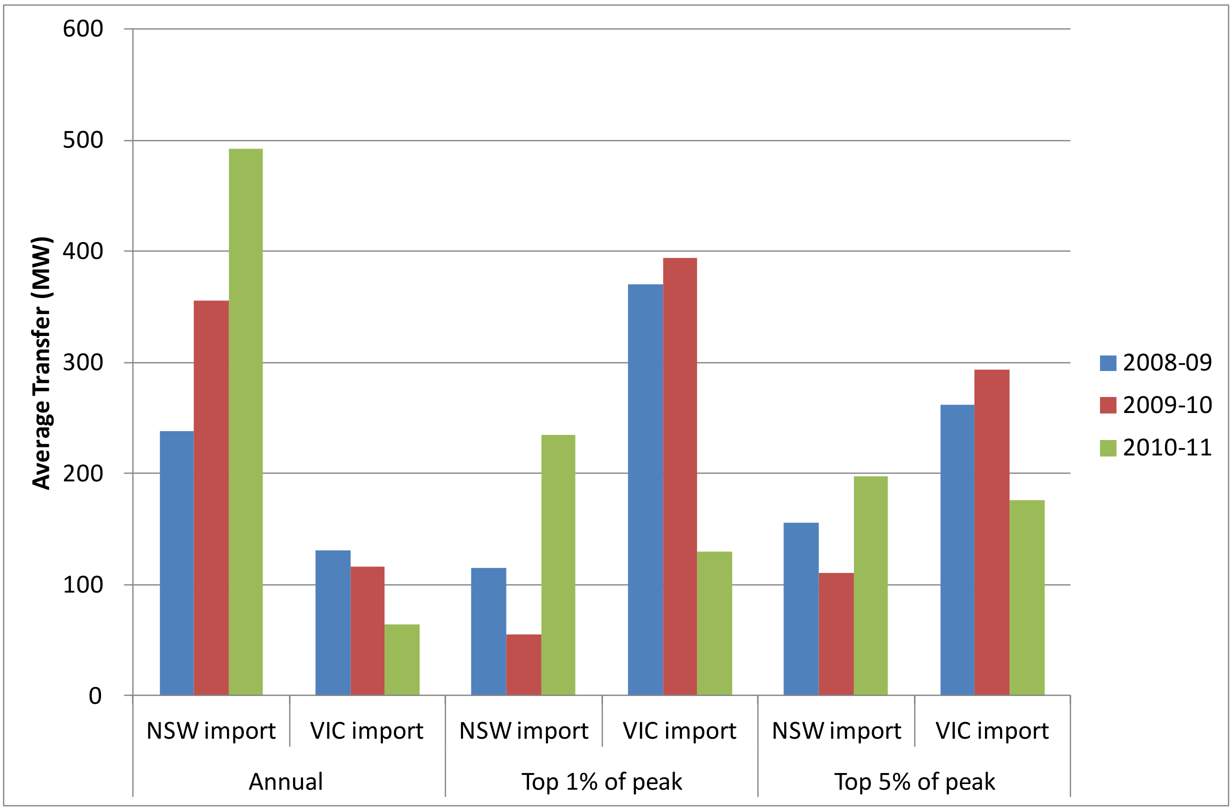
[2] NLCAS is the capability of reducing an active power flow from a transmission network in order to keep the electrical current loading on interconnector transmission elements within their respective ratings following a credible contingency event in a transmission network.
[3] A credible contingency 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.
[4] 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.
[5] For more information about the new NSCAS Rules, see the National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011 No.2.
[6] 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:[7]

- 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 arising from a reduction in the costs associated with involuntary unserved energy.

[7] AEMO. "The Constraint Report 2010". Available at http://wwww.aemo.com.au/electricityops/0200-0006.html

3 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.

The PSCR 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.

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 5.1, 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[8] whenever low reserve is forecast in Victoria

The modelled expected number of hours this would occur is shown in is shown in Section 5.1, however the hours required could be more or less depending on conditions.

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

4 Cost-benefit assessment of credible options

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.[9]

To measure the increase in net market benefit, AEMO has analysed the classes of market benefit required for consideration under the RIT-T, as set out in subparagraph 5 of the RIT-T.[10]

4.1 Methodology

The methodology and assumptions used in this market benefit analysis were based on those used to produce the 2010 National Transmission Network Development Plan (NTNDP).[11]

Time-sequential market simulations were undertaken for the six years from 2012–13 to 2017–18 to evaluate the market benefits of the credible options.

Time-sequential market simulations attempt to represent the complex interaction between consumer and producer behaviours, technical infrastructure, and the variability of environmental factors (weather, wind, and solar radiation).

The model used for this RIT-T simulates NEM dispatch at hourly resolution with five pricing regions linked by interconnectors. The transmission network is modelled via a set of network constraint equations representing the inter-regional and intra-regional network, similar to those used by AEMO's National Electricity Market Dispatch Engine (NEMDE). The constraint equations put bounds on the generation dispatch to ensure the system is secure and can sustain credible contingencies.

A significant amount of the market benefits associated with the credible options may be attributed to rare occasions, where multiple generator outages coincide with high demand. To capture these rare occasions a monte-carlo algorithm was 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 were based on 200 monte-carlo simulations.

The market benefits of the credible options were calculated by comparing the results of two states of the world:

- the base case, with the Murray-Dederang line capability limited to its 15 minute short term rating, and
- the upgrade case, with the Murray-Dederang line capability increased to its 5-minute short term rating.

4.2 Assumptions

The modelling assumptions were based on the 2010 NTNDP database including:

- Fuel and variable operating and maintenance costs.
- New entrant generation costs.
- Minimum generation levels.
- Network constraint equations.
- Scheduled and unplanned outage rates.

The critical assumptions, including updates from the 2010 dataset for this RIT-T, are discussed below.

[9] NER clause 5.6.5B (b)
[10] NER 5.6.5B(c)(4); and AER, *Final Regulatory Investment Test for Transmission*, June 2010, version 1, paragraph 5, page 4.
[11] AEMO. "2010 National Transmission Network Development Plan". Available at http://www.aemo.com.au/planning/ntndp.html

4.2.1 Demand forecasts and profile

The modelling used the medium economic demand forecasts from the 2011 Electricity Statement of Opportunities (ESOO)[12] except in the case of Victoria where updated forecasts were used. These updated forecasts were reported in the 2011 ESOO Update[13] and represent a 114 MW reduction in Victorian maximum demand levels compared with the 2011 ESOO forecasts.

The modelled hourly demand profile was based on the 2009–10 historical profile scaled to match the forecast maximum demand and energy values.

The modelling was undertaken using two demand profiles – representing 50% probability of exceedance (POE) and 10% POE maximum demand forecasts. The modelling results from these two profiles were weighted 70% and 30% respectively.

4.2.2 Value of customer reliability

The cost of unserved energy was 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.

The regional VCR values used by AEMO to calculate the cost of expected unserved energy are shown in Table 1.

Table 1 – 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

4.2.3 Generator capacity

Modelled generator capacities were based on the 2011 ESOO. Modelled wind generation profiles for existing wind farms were based on the 2009–10 historical profiles where possible.

Modelled new wind generators, and existing wind generators committed after 2009–10, were modelled using synthetic hourly wind power profiles generated by the CSIRO Meso-scale atmospheric wind model.[14]

4.2.4 Generator unit outage rates

The generator unit outage rates used for this RIT-T, shown in Table 2, 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 2 – 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%

4.2.5 Demand side participation

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

[12] AEMO. "2011 Electricity Statement of Opportunities". Available at http://www.aemo.com.au/planning/esoo2011.html
[13] AEMO. "2011 Electricity Statement of Opportunities Update". Available at http://www.aemo.com.au/planning/esoo2011.htm
[14] For more details see: AEMO "Wind Integration in Electricity Grids Work Package 5: Market Simulation Studies". Available at http://www.aemo.com.au/planning/wind_integration_investigation.html

4.2.6 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.

4.3 Reasonable scenarios considered

The market benefits of the credible options have been evaluated under the 2010 NTNDP's Decentralised World scenario, combined with a low carbon price trajectory (DW-L).

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).[17]

The market benefits of the credible options have 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.[18]

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 3.

Table 3 – 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 2 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%[19] (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.

[17] See 2010 NTNDP for more information on the least cost modelling algorithm.
[18] Committed new entry and retirement from 2011 Electricity Statement of Opportunities.
[19] Wind farm contribution factors from 2011 Electricity Statement of Opportunities.

Figure 3 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.

Figure 2 – Victoria supply-demand balance (Scenario 1)

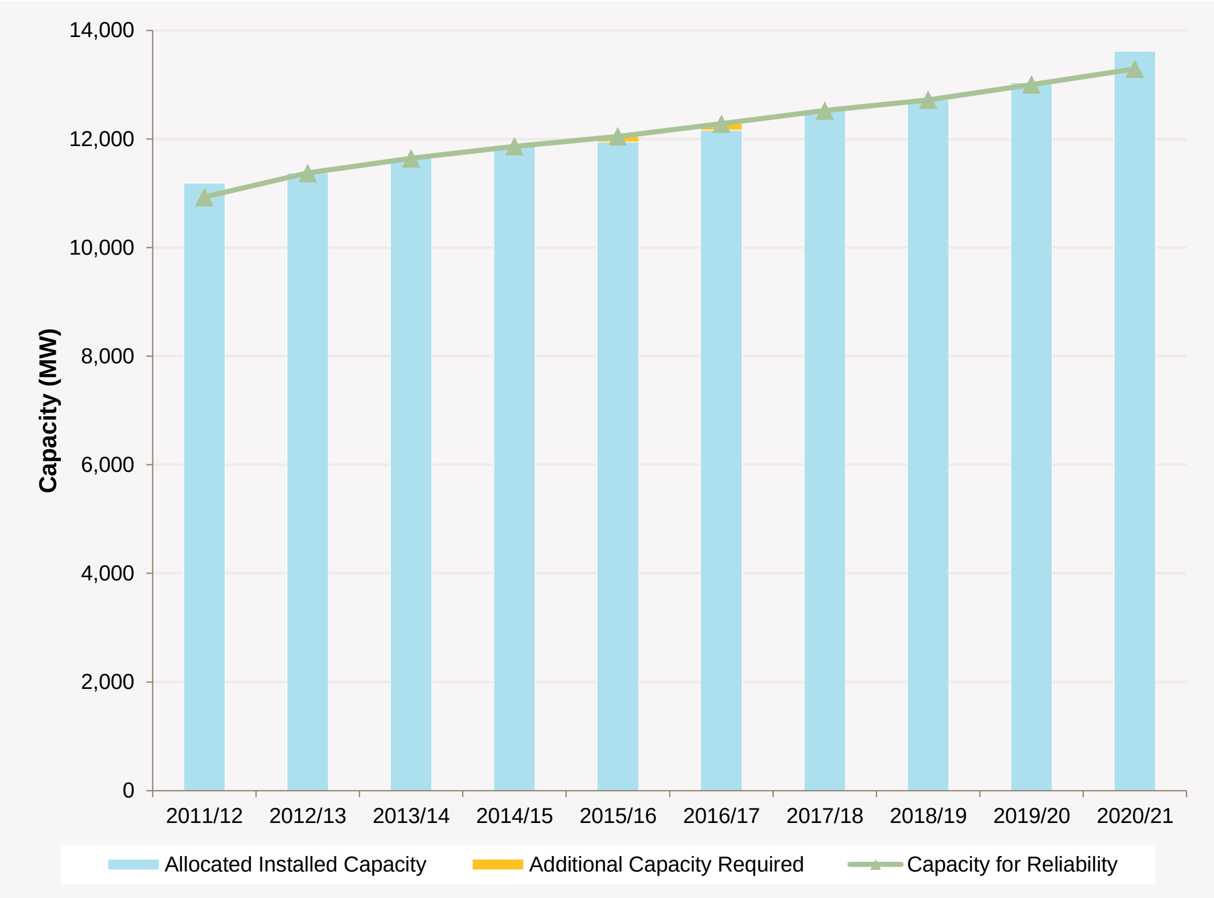


Figure 3 – New South Wales supply-demand balance (Scenario 1)

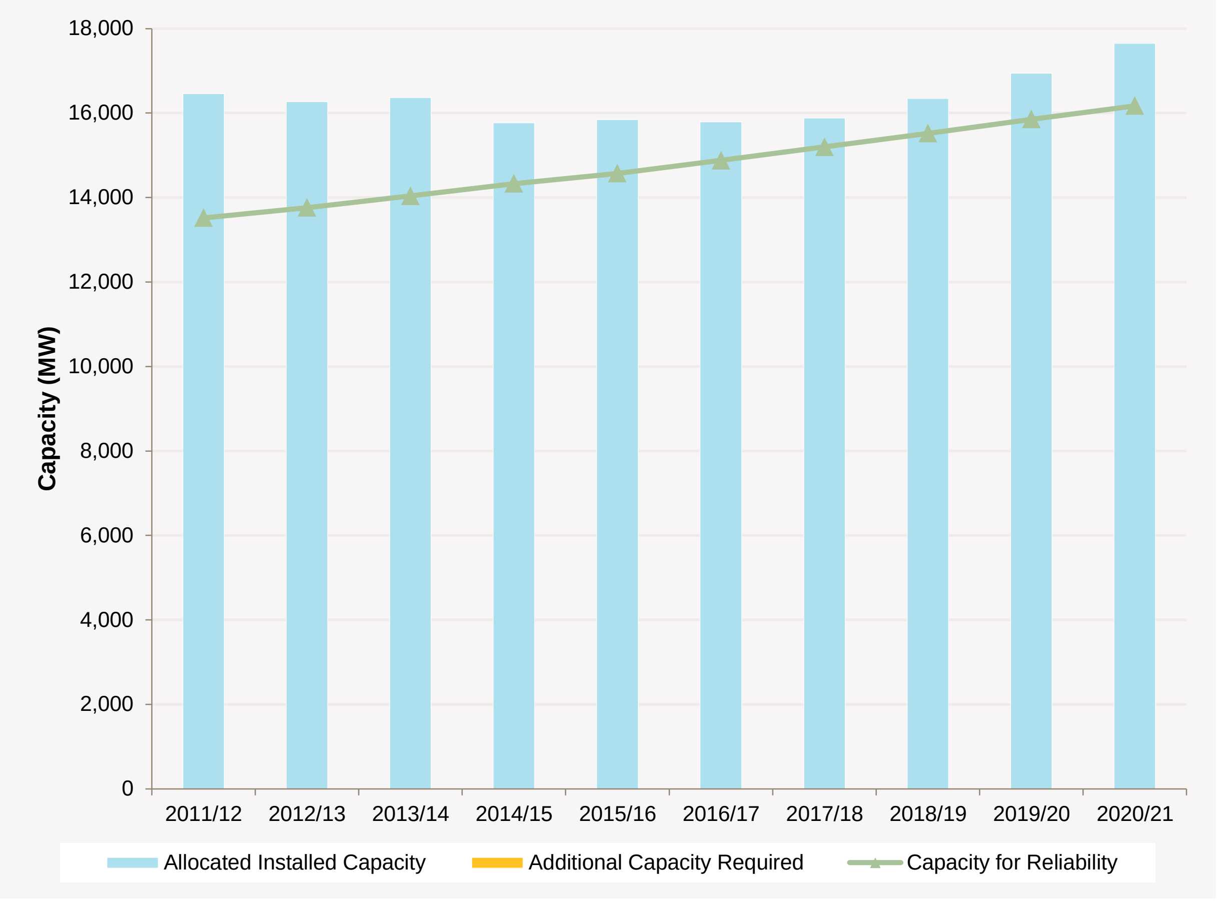
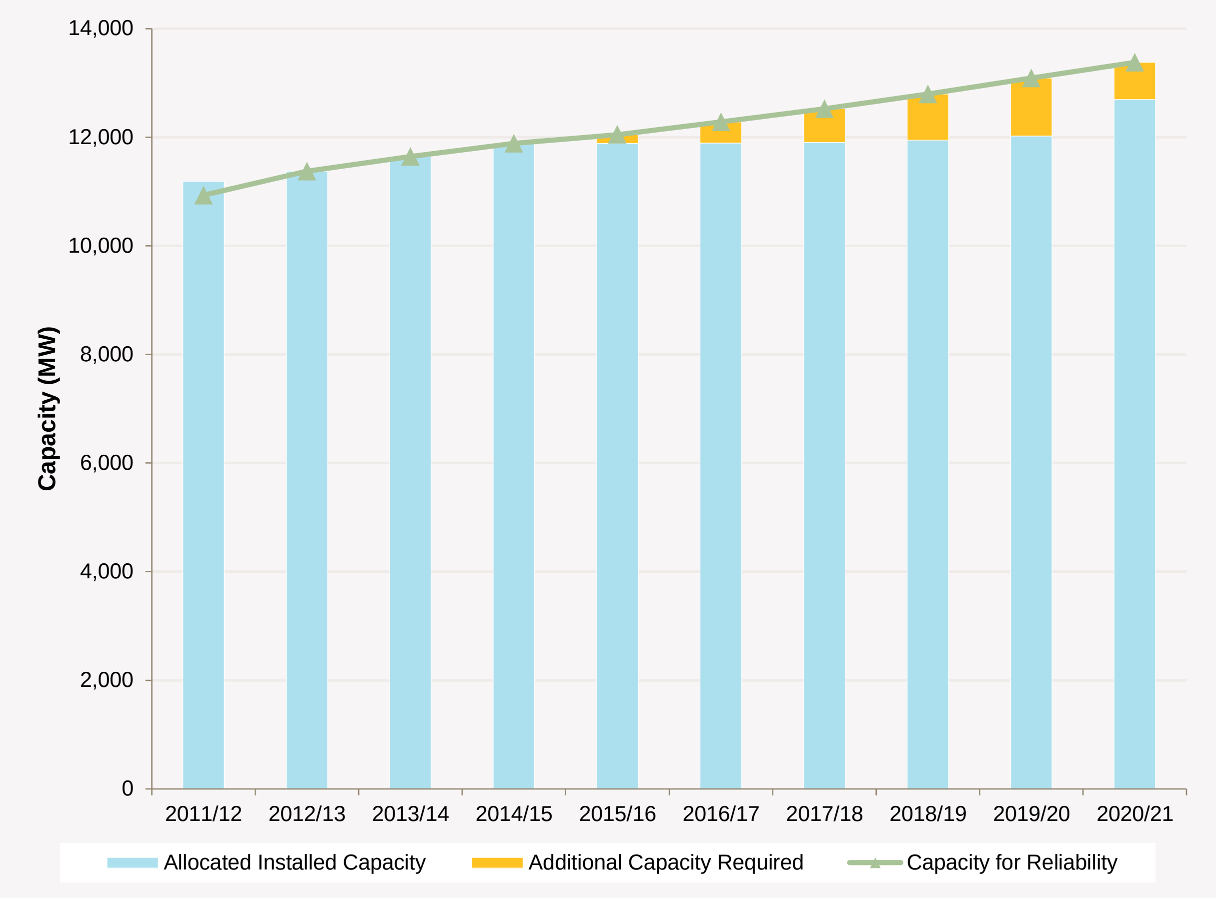


Figure 4 shows the Victorian supply-demand balance at time of Victorian summer peak under Scenario 2 assuming existing interconnector limits. Victoria experiences a shortfall in supply from 2015–16 under this scenario.

Figure 4 – Victoria supply-demand balance (Scenario 2)



4.4 Market benefits categories considered

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]

The following classes of market benefits have been evaluated for the credible options in this RIT-T:

- **Changes in involuntary load shedding**

During periods of high demand in Victoria the increase in available supply from New South Wales reduces 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 leads to an increase in the amount of voluntary load curtailment (and a decrease in involuntary load shedding).

As detailed in the PSCR, AEMO considers that the following classes of market benefits are not material for this RIT-T assessment:

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

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

The non-network demand management options result in reductions in dispatch costs. Option 1, load reduction control scheme enables 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, reduces 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 total cost of the limitation arising from reductions in voluntary and involuntary load reduction (as shown in the PSCR).

- **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.

- **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 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.

- **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

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

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.

4.5 Market benefits results

Table 4 and Table 5 shows the annual estimated market benefits of the credible options, weighted according to the 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 4 – Annual estimated market benefits for Scenario 1 ($ million)

Benefit Type	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
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	1.1	2.8	2.0	2.8	2.8	1.1

Table 5 – Annual estimated market benefits for Scenario 2 ($ million)

Benefit Type	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
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	2.7	5.3	8.6	10.3	10.9

Table 6 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.

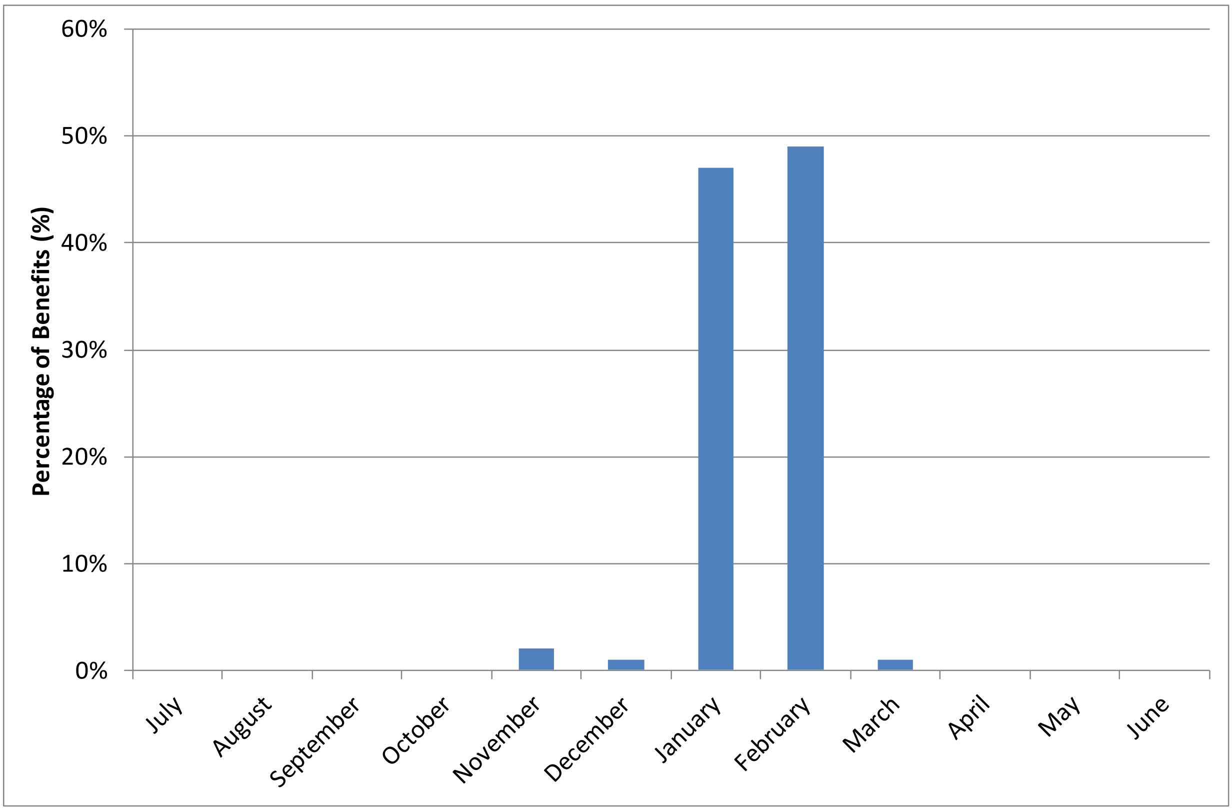
This equates to an available present value of gross market benefits of $17.4 million over the period from 2012–13 to 2017-18, assuming a 10% discount rate.

Table 6 – Annual estimated market benefits – probability weighted ($ million)

Benefit Type	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18
Involuntary load reduction benefits	1.0	2.5	3.3	5.4	6.2	5.6
Voluntary load curtailment Benefits	0.1	0.3	0.3	0.4	0.4	0.4
Total benefits	1.1	2.7	3.7	5.7	6.6	6.0

Figure 5 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 5 – Monthly market benefits



5 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 a 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 6.

To evaluate the potential net benefits of a potential non-network demand management options in this RIT-T, the cost structure shown in Table 7 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 as part of the tender process.

Table 7 – 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 8 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 8 – 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 ($)	-26,073	1,459,123	2,333,151	4,328,916	4,998,690	4,365,694

Table 9 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. For the purpose of this example, it is assumed that this option does not have an enablement cost in addition to the load shedding cost.

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

Table 9 – 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 ($)	1,350,000	1,910,046	2,230,062	2,930,097	3,220,111	2,980,099
Net benefit ($)	-210,000	834,955	1,419,939	2,794,904	3,354,889	3,024,901

Table 10 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 10 – Net present value of Option 1 and Option 2 ($)

Discount rate	Option 1	Option 2
12%	11.5	7.3
10%	13.5	8.6
6%	10.6	6.7

Table 10 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.

5.1 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 11 (Scenario 1) and Table 12 (Scenario 2) for both 10% POE and 50% POE conditions. The maximum enablement hours are the maximum 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 11 – 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 12 – 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 an 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 13.

Table 13 – 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

Because the network limitation is load-driven, a non-network option would be given day-ahead notice when there is a high probability of the network limitation occurring. Such notice would be based on the forecast weather conditions and the Short Term Projected Assessment of System Adequacy (ST PASA).[23]

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.

5.2 Material interregional impact

In accordance with NER 5.6.6(c)(6)(ii), AEMO has considered whether any of the credible options 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.

[23] The ST PASA process is run every two hours and provides reserve forecast information for the NEM for every half-hour over the next seven days. It is available on the AEMO website at http://www.aemo.com.au/data/outlook.html.

6 Consultation process

The NER sets out a three step process for undertaking RIT-T assessments:

- Stage one involves preparing a PSCR. The PSCR informs the market of the upcoming network limitations and potential investment options, with a focus on providing information to proponents of non-network solutions. The PSCR is open for consultation for a period not less than 12 weeks.
- Stage two involves preparing a PADR. The PADR presents the results of the economic cost-benefit test and identifies the preferred investment option for consultation. The PADR is open for consultation for a period of not less than 6 weeks.
- Stage three involves preparing a PACR. The PACR recommends an investment.

Under clause 5.6.6 (y) of the NER, transmission network service providers (TNSPs) are exempt from providing a PADR if all the following conditions are met:

- The estimated capital cost of the preferred option is less than $35 million.
- The TNSP has identified the preferred option in its PSCR, 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.

In the PSCR for this RIT-T, AEMO noted its exemption from publishing a PADR for the following reasons:

- As the identified need is an increase in net market benefits, the cost of the preferred option must be less than the increase in gross market benefits. The expected total increase in gross market benefits is $25.8 million over the period from 2012–13 to 2016–17 and hence the cost of the option must be less than $25.8 million.
- The preferred option does not have material market benefits other than those associated with changes in voluntary load curtailment and involuntary load shedding

The PSCR in relation to this RIT-T was published on 19 December 2011 and was open for consultation until 16 March 2012. No submissions were received in response to the PSCR.

7 Recommended action

The recommended action is implementation of a non-network demand management option with the technical characteristics shown in Section 5.1 by November 2012 for a period of up to 6 years at a cost less than the gross market benefits.

The gross market benefits available are $25.8 million over the period from 2012–13 to 2017–18, or $17.4 million in net present value terms using a 10% discount rate.

AEMO will commence the tender process to allow potential service providers to tender their services in the second half of 2012.

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