EASTERN METROPOLITAN MELBOURNE THERMAL CAPACITY UPGRADE – RIT-T: PROJECT ASSESSMENT DRAFT REPORT

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Executive Summary

This Project Assessment Draft Report (PADR) has been prepared by the Australian Energy Market Operator (AEMO) as required by clause 5.16.4(j) of the National Electricity Rules (NER) given AEMO's capacity as the jurisdictional planning body responsible for planning and directing augmentations to the Victorian Declared Shared Network (DSN).

Identified need

From summer 2016-17, under certain conditions, the supply security of customers in the Eastern Metropolitan Melbourne area is at risk, due to potential overload on the existing 500/220kV transformers at Rowville and Cranbourne.

When this RIT-T commenced in late-2011, the need for additional transformation capability was identified as being required prior to summer 2015-16.

Revised demand forecasts produced in 2012, which show growth in Victoria's maximum demand has dropped from around 2.2% per annum to 1.6% per annum, has meant this need has been deferred by around 3 years to additional transformation capability being required prior to summer 2018-19.

Increasing the supply capability to Eastern Metropolitan Melbourne will reduce the reliance on local generation and increase the ability of generation from the rest of the NEM to supply the bulk demand areas around Metropolitan Melbourne.

Preferred option

The PADR recommends:

- The proposed preferred option is installation of a new (third) 1000 MVA 500/220 kV transformer at Rowville Terminal Station, with a proposed commissioning date of November 2018.
- The indicative total project cost, inclusive of operating costs, is estimated at $51 million (in present value terms).

This option is forecast to deliver positive net market benefits of $522 million (in present value terms), over the 40 year assumed life of the asset, and satisfies the Regulatory Investment Test-Transmission (RIT-T).

Submissions and next steps

This PADR represents stage two of the consultation process in relation to the Eastern Metropolitan Melbourne thermal capacity Regulatory Investment Test for Transmission (RIT-T).

AEMO welcome written submissions on this PADR, on or before Friday 19 April 2013. Submissions should be emailed to planning@aemo.com.au, and will be published on the AEMO website.

AEMO will consider submissions in preparing the Project Assessment Conclusions Report, which represents the final step in the RIT-T process for this investment.

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1 Introduction

1.1 Overview

This PADR represents stage two of the consultation process in relation to the Eastern Metropolitan Melbourne thermal capacity Regulatory Investment Test for Transmission (RIT-T).

This PADR[1]:

- Describes the identified need that AEMO is seeking to address, namely an increase in overall net market benefit.
- Describes the credible options that AEMO has assessed and that are considered may address the identified need.
- Notes that no submissions were received in response to the PSCR previously published by AEMO.
- Provides a quantification of costs (with a breakdown of operating and capital expenditure) and classes of material market benefits for each of the credible options, together with a description of the methodologies adopted by AEMO in undertaking this quantification.
- Provides reasons why differences in the timing of transmission investment, changes in ancillary services costs, option value, competition benefits, and changes in costs for parties other than AEMO are not material to this RIT-T assessment.
- Notes that there is not expected to be any material market benefits arising outside the Victorian region of the NEM.
- Provides the results of the net present value (NPV) analysis for each credible option assessed, together with accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option for investment by AEMO, including its technical charcteristics, estimated construction timetable and commissioning date, noting that it satisfies the RIT-T.
- Seeks submissions from Registered Participants and interested parties on the preferred option presented.

1.2 Background to the RIT-T

The purpose, principles and procedures of the RIT-T are set out in NER clause 5.16. These provisions were put in place following the Australian Energy Market Commission's (AEMC) national transmission planning arrangements review in 2008.[2]

The purpose of the RIT-T is to rank various transmission investment options and identify the option that maximises net economic benefits and, where applicable, meets the relevant jurisdictional or NER-based reliability standards.[3] The RIT-T replaced the regulatory test for transmission investments and removed the distinction in the regulatory test between reliability driven projects and projects motivated by the delivery of market benefits, acting as a single framework for assessing all transmission investments.

As outlined in NER Clause 5.16.4, the RIT-T process involves three primary steps, namely:

- Producing a Project Specification Consultation Report (PSCR).

[1] Prepared by AEMO under clause 5.16.4(j) of the NER and AEMO's capacity as the jurisdictional planning body responsible for planning and directing augmentations to the Victorian Declared Shared Network (DSN).
[2] AEMC, National transmission planning arrangements, Final report to MCE, 2008.
[3] AER, Regulatory investment test for transmission, Issues Paper, September 2008, p.1.

- Producing a Project Assessment Draft Report (PADR).[4]
- Producing a Project Assessment Conclusions Report (PACR).

As part of the PADR and the PACR, the transmission network service provider (TNSP) must present the results of the RIT-T analysis. This analysis is based on quantification of various categories of costs and benefits arising in the National Electricity Market (NEM). Both positive and negative market impacts are included as part of this assessment.

Consistent with the NER, Section 5 of this PADR provides a description of the analysis methodology, along with a detailed description of the assumptions underlying the RIT-T assessment. Importantly, the RIT-T assessment is an assessment of the relative costs and benefits[5] of alternative options, in order to identify the option which maximises net economic benefits.

The materiality of the assumptions underlying the quantification of the costs and benefits is therefore dependent on the extent to which changes in those assumptions are expected to affect the relative ranking of the options under the RIT-T. Variations in assumptions which result in a change in the value of the net market benefit calculated for a particular option, but leave the relative net benefit of that option unchanged relative to alternative options, are not material for the RIT-T assessment.

1.3 Submissions

AEMO invites written submissions on this Project Assessment Draft Report from registered participants and interested parties.

Submissions are due on or before Friday 19 April 2013.

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 third stage of the RIT-T process, the Project Assessment Conclusions Report (PACR), will include the matters outlined in this PADR and consideration of any submissions made in response to this PADR.

Further details in relation to this RIT-T can be obtained from:

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[4] Under certain circumstances a transmission network service provider (TNSP) may discharge its obligation to preparation of a PADR (see: NER, 5.16(m)).

[5] Note that different categories of market benefit may be positive or negative, for each option assessed.

2 Identified Need

2.1 Background

In the 2011 Victorian Annual Planning Report (VAPR) and the 2010, 2011 and 2012 National Transmission Network Development Plan (NTNDP), AEMO identified that due to continual demand growth in the Eastern Metropolitan Melbourne area, action will be required to prevent loading a number of transmission elements beyond their thermal capability. The VAPR studies suggested that there are potential economic benefits associated with increasing the thermal supply capability to Eastern Metropolitan Melbourne.[6,7]

To further investigate the costs associated with the Eastern Metropolitan Melbourne thermal limitations, and the benefits of taking action to mitigate reaching these limitations, AEMO commenced a regulatory investment test (RIT-T). In November 2011, AEMO published the first stage of this RIT-T, the Project Specification Consultation Report (PSCR), with submissions from interested parties invited by 17 February 2012. No submissions to the PSCR were received.

AEMO intended on publishing this PADR report as the second stage in the RIT-T process soon after the PSCR consultation process closed. However due to a reduction in forecast Victorian demand, AEMO decided to delay the detailed option analysis until the terminal station demand forecasts where finalised and published on AEMO's website on 28 September 2012. Waiting for the terminal station demand forecasts has allowed AEMO to ensure that the cost-benefit assessment of each option is based on more robust and realistic assumptions.

Additionally, since publication of the PSCR for this RIT-T, and publication of past Victorian annual planning reports, AEMO has been working with SP AusNet to identify the exact cause of limitations on the East Rowville – Rowville 220 kV line. This review has resulted in an increased rating for this line.

Utilising the amended rating provided by SP AusNet for the East Rowville – Rowville 220 kV line, there is no longer an identified need to reduce the expected loading on this line within the analysis period, which has led to the elimination of some options previously proposed in the PSCR, as described in Section 3.3. The revised loading on the East Rowville – Rowville 220 kV line is presented in Table 1, Section 2.2.

Because publication of this PADR extended beyond twelve months since the PSCR consultation period concluded, AEMO requested and was granted a six week extension period from the Australian Energy Regulator (AER) to publish this PADR by 31 March 2013.

2.2 Summary of the identified need

The 'identified need' for the proposed investment is an increase in the sum of consumer and producer surplus in the NEM, i.e. an increase in net market benefit. AEMO believes that reducing the expected involuntary load shedding, required to maintain loading levels within existing network capabilities, will achieve this, in the case of the preferred proposed option, by augmenting the transmission network.

Consideration has been given in particular to:

- Increasing the 500/220 kV transformer thermal supply capability into the Eastern Metropolitan Melbourne area.

6 AEMO. "Victorian Annual Planning Report 2011". Available http://www.aemo.com.au/Electricity/Planning/2011-Victorian-Annual-Planning-Report. Accessed May 2012.
7 AEMO. "National Transmission Network Development Plan 2010". Available http://www.aemo.com.au/Electricity/Planning/2011-National-Transmission-Network-Development-Plan. Accessed May 2012.

- Increasing the number of 500/220 kV transformers supplying the 220 kV Metropolitan Melbourne area.

The specific thermal network limitations expected to be reached as a result of demand growth in the Eastern Metropolitan Melbourne area, and that this RIT-T primarily aims to address, include:

- Cranbourne A1 500/220 kV transformer loading.
- Rowville A1 500/220 kV transformer loading.
- Rowville A2 500/220 kV transformer loading.

The three 1000 MVA 500/220 kV transformers at Rowville and Cranbourne are key components in supplying electricity from the 500 kV to the 220 kV transmission network in Melbourne's east. Rowville Terminal Station operates with a split bus arrangement. Due to this 220 kV split bus arrangement, the Rowville A2 500/220 kV transformer and the 220 kV lines from Rowville to East Rowville and East Rowville to Cranbourne work in parallel with the Cranbourne A1 500/220 kV transformer to supply load connected to the terminal stations at East Rowville, Cranbourne, Tyabb, Western Port (JLA) and the Wonthaggi Desalination Plant, as well as Richmond, via the Rowville – Richmond 220 kV line.

The Rowville A1 500/220 kV transformer supplies load connected to the Heatherton, Malvern, Ringwood, Springvale and Templestowe terminal stations via 220 kV lines connected out from Rowville.

In addition to the specific network limitations that this RIT-T is aiming to address, the assessment also considered other key limitations in the Melbourne Metropolitan area in order to determine the overall market benefits associated with each credible option assessed. Some of these other key network limitations include the thermal loading limits of the:

- South Morang H1 and H2 330/220 kV transformers.
- South Morang – Thomastown 220 kV line.
- Rowville – Ringwood 220 kV line.
- Ringwood – Thomastown 220 kV line.
- Rowville – Templestowe 220 kV line.
- Keilor – Thomastown 220 kV lines.
- Keilor A2 and A4 500/220 kV transformers.
- Moorabool A1 and A2 500/220 kV transformers.

Under certain demand conditions, the thermal limits of these network elements can limit supply capability with all network elements in service.

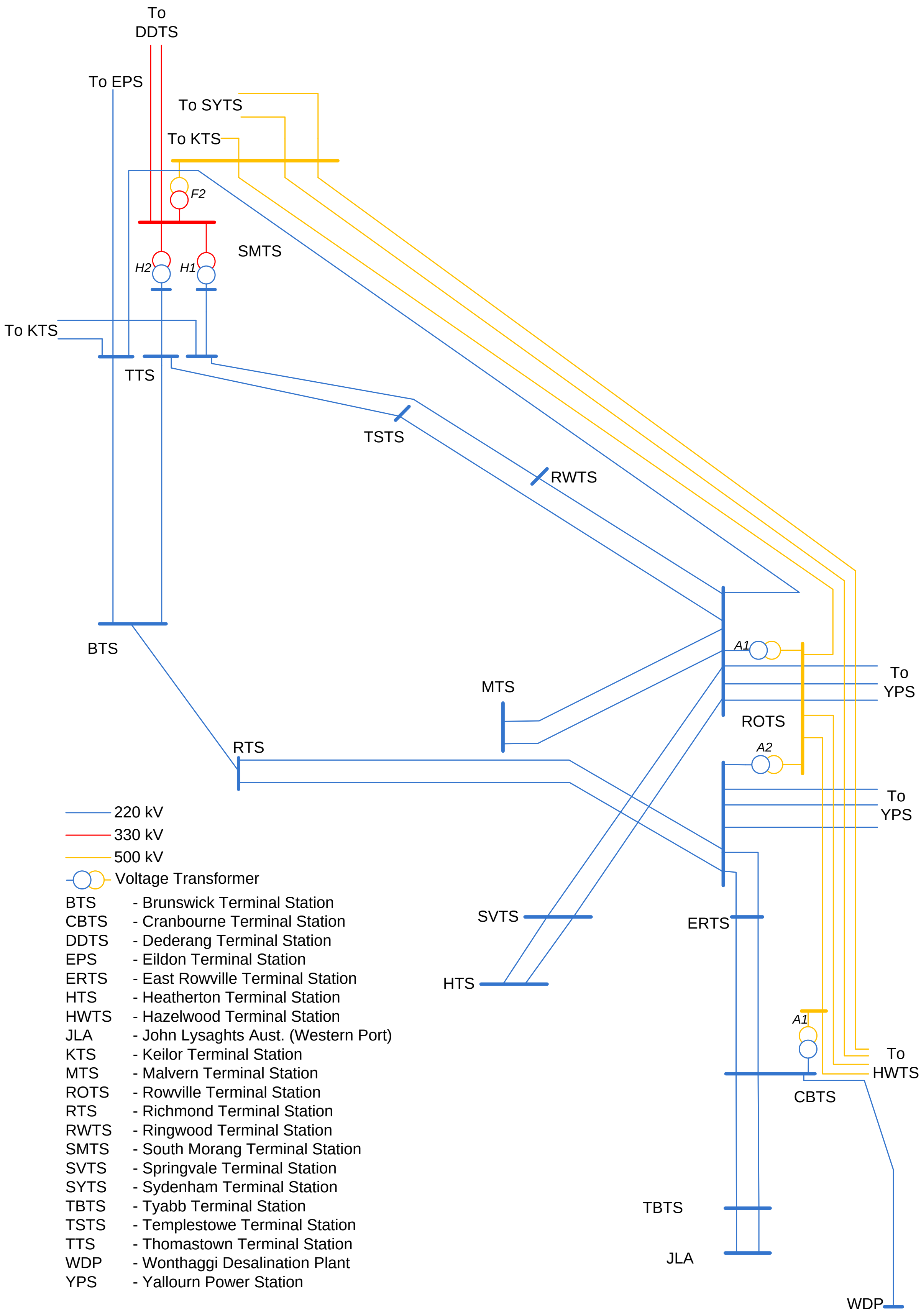
Table 1 shows the forecast loading of key transmission plant elements in the Eastern Metropolitan Melbourne area under critical conditions, which can be either system normal or N-1 conditions. The loading conditions are presented under Victorian peak demand conditions assuming an ambient temperature of 45°C. System normal loading is compared to the element's continuous rating, while N-1 loading levels have been compared to the element's short-term rating, which is a higher rating that can be utilised for a limited time only until further action can be undertaken. All the forecast overloads presented in Table 1 are expected to result in pre-contingent action to manage system normal or post-contingent loading levels.

Table 1: Transmission element loadings under summer peak demand conditions

Transmission asset	Critical condition	2015–16	2016–17	2017–18	2018–19
CBTS A1 500/220 kV transformer	System normal	86%	90%	87%	88%
ROTS A1 500/220 kV transformer	System normal	94%	98%	100%	101%
ROTS A2 500/220 kV transformer	CBTS A1 outage	83%	86%	84%	85%
ROTS – ERTS 220 kV line	CBTS A1 outage	87%	93%	88%	90%

Figure 1 presents an approximate geographical schematic of the key terminal stations affected by the network limitations that are forecast to be reached. During peak demand periods, when the network limits are expected to impact market outcomes, electricity is generally supplied to Melbourne via 500 kV lines from Hazelwood, 220 kV lines from Yallourn and Eildon, and 330 kV lines from Dederang.

Figure 1: Approximate geographical representation of affected area



3 Credible options included in the RIT-T analysis

The following six options have been included as potential credible options in the RIT-T analysis:

- Option 1: Cranbourne 500/220 kV transformer installation and connection of the No.3 Hazelwood – Rowville 500 kV line at Cranbourne.
- Option 2: Rowville 500/220 kV transformer installation.
- Option 3: Ringwood 500 kV establishment and 500/220 kV transformer installation.
- Option 4: Templestowe 500 kV establishment and 500/220 kV transformer installation.
- Option 5: Non-network support in the form of demand management.
- Option 6: Non-network support in the form of local generation.

Option 1 predominately off-loads the existing Cranbourne 500/220 kV transformer, the Rowville A2 500/220 kV transformer and the 220 kV lines in the South-East Metropolitan Melbourne area, whereas Options 2 through 6 are better at off-loading the Rowville A1 500/220 kV transformer and supplying the 220 kV lines connecting Rowville to Ringwood, Malvern, Thomastown and Springvale. Each of the credible options assessed will result in some residual load at risk, particularly on the opposite bus group to where it is connected.

3.1 Description of the credible network options assessed

This section provides a description of each of the credible network options assessed in the RIT-T, including:

- The technical characteristics of the option.
- The estimated construction timetable and commissioning date.
- The estimated capital and operating costs.

Section 3.2 provides the equivalent description of each credible non-network option assessed in this RIT-T.

Base case – Do Nothing

Clause 5.16.1(c)(1) of the NER requires that the RIT-T be based on a cost-benefit analysis that includes an assessment of reasonable scenarios of future supply and demand if each credible option were implemented compared to the situation where no option is implemented.

The 'Do Nothing' base option gives the basis for comparing the cost-benefit assessment of each credible option.

Under the Do Nothing option the action required to ensure that network loading levels remain within transmission network equipment thermal limits is involuntary load shedding, since generation support on the demand side of the network limitations is limited and the existing capacity is insufficient to prevent involuntary load shedding being required. The cost of involuntary load shedding is calculated using the value of customer reliability (VCR), which is the value that, based on surveys, customers place on a reliable level of electricity supply. The VCR applied in this RIT-T PADR is $61,950/MWh (in 2013-14 Australian dollars).

Option 1 – New 500/220 kV transformer at CBTS

The proposed scope of works for Option 1 involves the installation of a new 1000 MVA A2 500/220 kV transformer at Cranbourne Terminal Station, along with switching in the Hazelwood – Rowville No.3 500 kV line at Cranbourne Terminal Station.

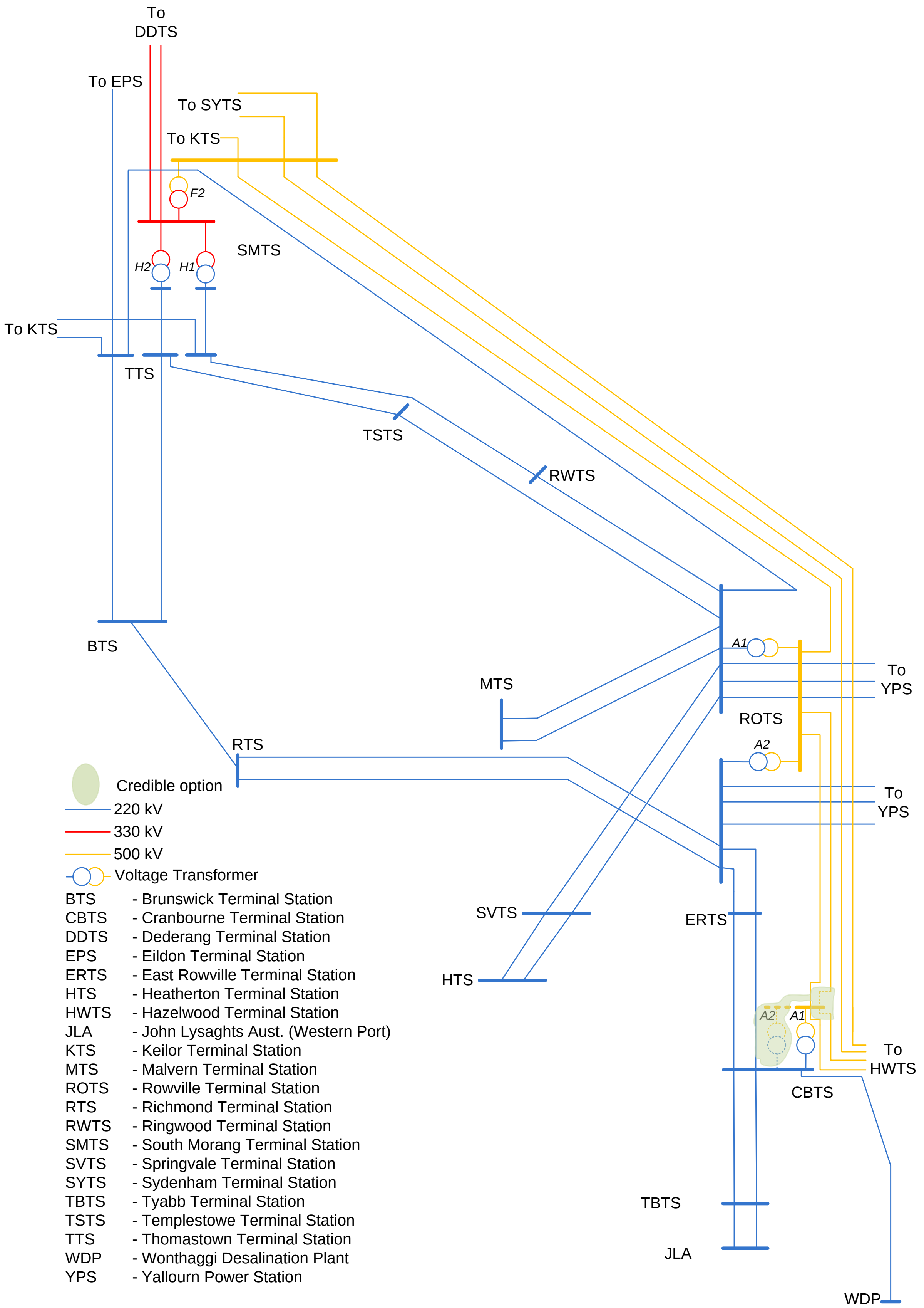
This option would provide a second 500/220 kV connection at Cranbourne, which will:

- Offload the Cranbourne A1 500/220 kV transformer.
- Offload the Rowville A2 500/220 kV transformer or enable it to be switched across to the Rowville No. 3-4 220 kV bus to offload the Rowville A1 500/220 kV transformer.
- Provide diversified transmission assets to supply Metropolitan Melbourne.

Including the cost of switching in the Hazelwood – Rowville No.3 500 kV line at Cranbourne Terminal Station, the estimated cost of this option is $83 million (±30%), in present value terms over the assumed 40 year life of the asset. The estimated construction lead time is three years. The augmentation cost includes $69 million in capital expenditure and $14 million in operating expenditure, which is estimated at 2% of the capital expenditure per annum.

Figure 2 shows the network topology with procurement of Option 1. The augmentations associated with this option are shaded in green.

Figure 2: Option 1 – Cranbourne 500/220 kV transformer installation



BTS	- Brunswick Terminal Station
CBTS	- Cranbourne Terminal Station
DDTS	- Dederang Terminal Station
EPS	- Eildon Terminal Station
ERTS	- East Rowville Terminal Station
HTS	- Heatherton Terminal Station
HWTS	- Hazelwood Terminal Station
JLA	- John Lysaghts Aust. (Western Port)
KTS	- Keilor Terminal Station
MTS	- Malvern Terminal Station
ROTS	- Rowville Terminal Station
RTS	- Richmond Terminal Station
RWTS	- Ringwood Terminal Station
SMTS	- South Morang Terminal Station
SVTS	- Springvale Terminal Station
SYTS	- Sydenham Terminal Station
TBTS	- Tyabb Terminal Station
TSTS	- Templestowe Terminal Station
TTS	- Thomastown Terminal Station
WDP	- Wonthaggi Desalination Plant
YPS	- Yallourn Power Station

Option 2 – New 500/220 kV transformer at ROTS

The proposed scope of works for Option 2 involves the installation of a new 1000 MVA A3 500/220 kV transformer at Rowville Terminal Station, connecting to the Rowville No.3-4 220 kV bus, in parallel with the existing Rowville A1 500/220 kV transformer.

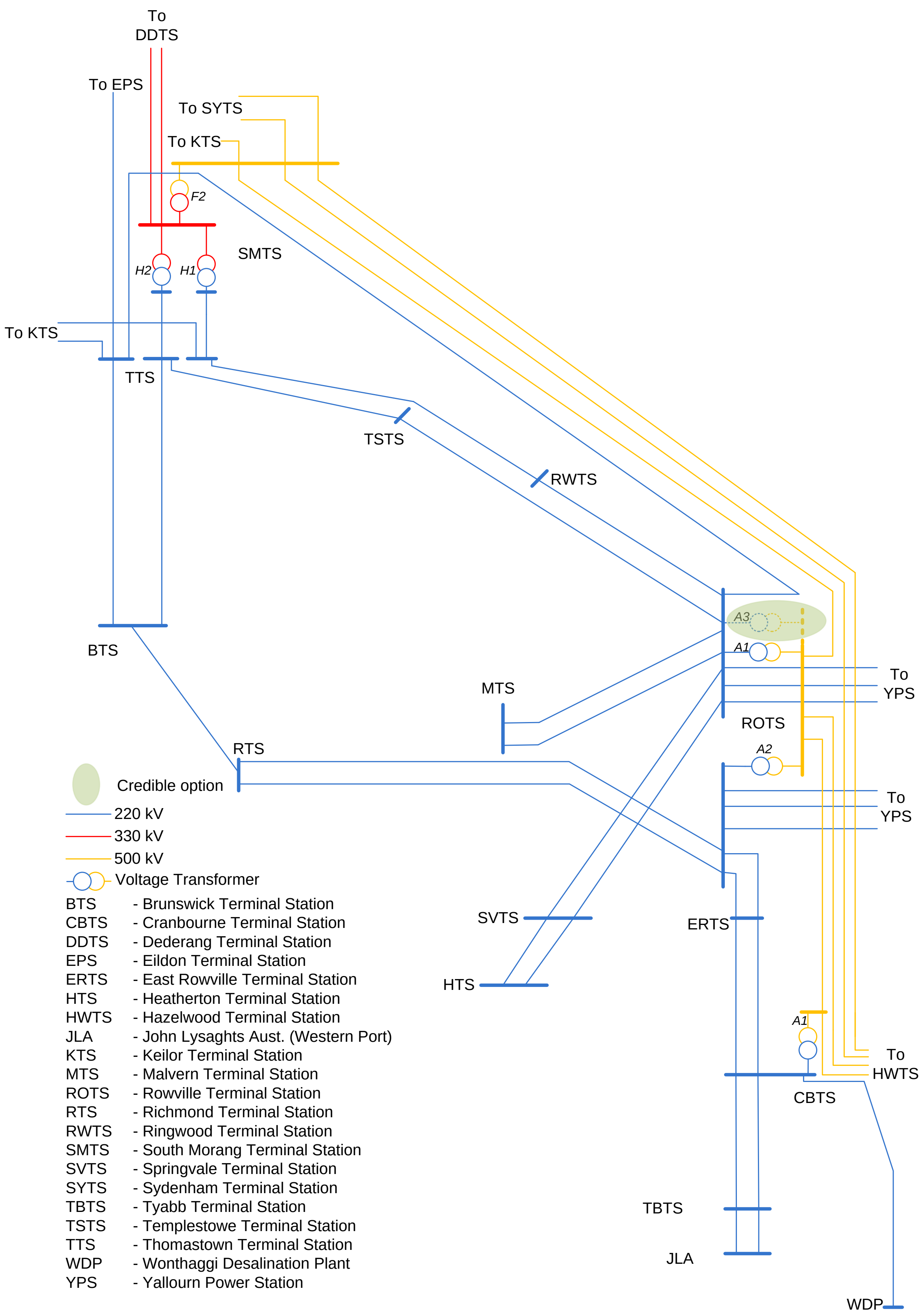
This option will provide a second 500/220 kV connection at Rowville, which will:

- Offload the Rowville A1 500/220 kV transformer.
- Offload the South Morang H1 and H2 330/220 kV transformers.

The estimated cost of this option is $51 million (±30%), in present value terms over the assumed 40 year life of the asset. The estimated construction lead time is three years. The augmentation cost includes $43 million in capital expenditure and $8 million in operating expenditure, which is estimated at 2% of the capital expenditure per annum.

Figure 3 shows the network topology with procurement of Option 2. The augmentations associated with this option are shaded in green.

Figure 3: Option 2 – Rowville 500/220 kV transformer installation



Option 3 – New 500 kV switchyard and 500/220 kV transformer at RWTS

The proposed scope of works for Option 3 involves the development of a new 500 kV switchyard and switching of a new 1000 MVA A1 500/220 kV transformer at Ringwood Terminal Station. This option will also require switching in of the Rowville – South Morang No.3 500 kV line at Ringwood Terminal Station.

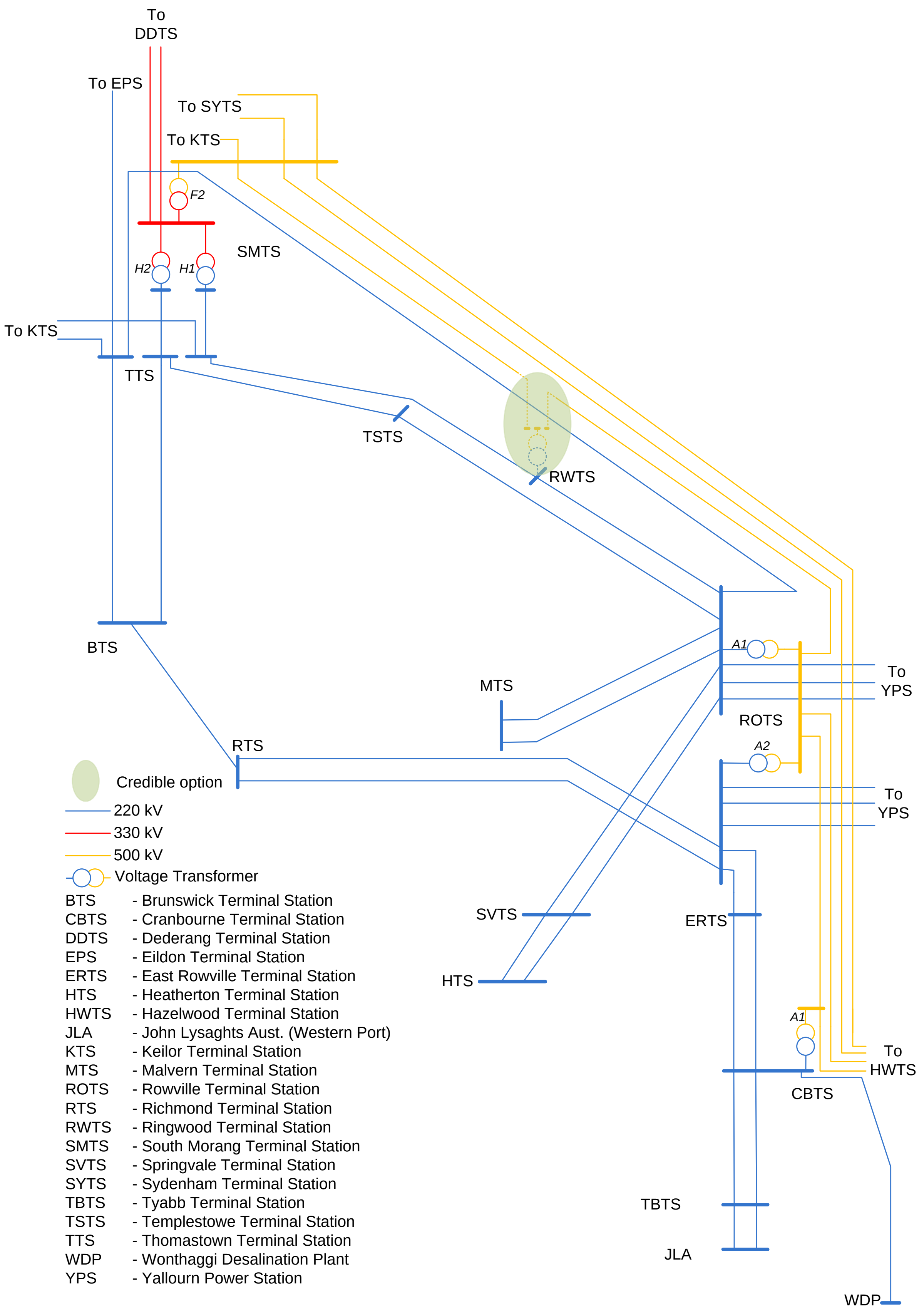
This option will provide a new 500 kV switchyard and 500/200 kV transformation at Ringwood, which will:

- Offload the Rowville A1 500/220 kV transformer.
- Offload the South Morang H1 and H2 330/220 kV transformers.

The estimated cost of this option is $105 million (±30%), in present value terms over the assumed 40 year life of the asset. The estimated construction lead time is four years. The augmentation cost includes $88 million in capital expenditure and $17 million in operating expenditure, which is estimated at 2% of the capital expenditure per annum.

Figure 4 shows the network topology with procurement of Option 3. The augmentations associated with this option are shaded in green.

Figure 4: Option 3 - Ringwood 500 kV switchyard establishment 500/220 kV transformer installation



Option 4 – New 500 kV switchyard and 500/220 kV transformer at TSTS

The proposed scope of works for Option 4 involves the development of a new 500 kV switchyard and switching of a new 1000 MVA A1 500/220 kV transformer at Templestowe Terminal Station. This option will also require switching in of the Rowville – South Morang No.3 500 kV line at Templestowe Terminal Station.

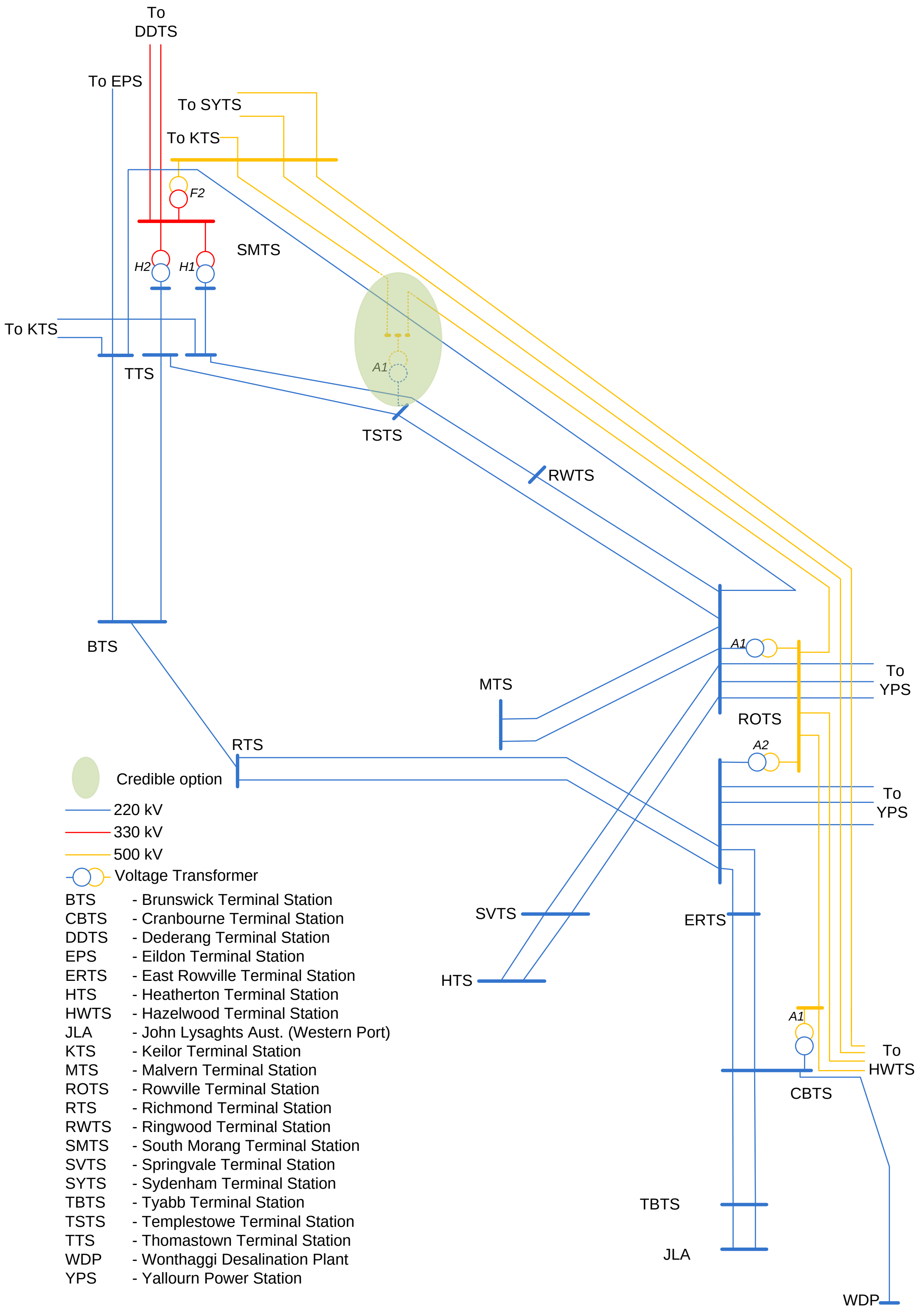
This option will provide a new 500 kV switchyard and 500/200 kV transformation at Templestowe, which will:

- Offload the Rowville A1 500/220 kV transformer.
- Offload the South Morang H1 and H2 330/220 kV transformers.

The estimated cost of this option is $182 million (±30%), in present value terms over the assumed 40 year life of the asset. The estimated construction lead time is four years. The augmentation cost includes $152 million in capital expenditure and $30 million in operating expenditure, which is estimated at 2% of the capital expenditure per annum.

Figure 5 shows the network topology with procurement of Option 4. The augmentations associated with this option are shaded in green.

Figure 5: Option 4 - Templestowe 500 kV switchyard establishment 500/220 kV transformer installation



3.2 Description of credible non-network options assessed

AEMO has included two non-network credible options in its assessment for this RIT-T.

No submissions to the PSCR were received to suggest whether or not the identified non-network options are commercially or technically feasible at the scale or within the timeframe required. AEMO has not undertaken any additional analysis to determine the technical feasibility of non-network options, however, the commercial feasibility has been assessed by AEMO utilising non-network cost assumptions developed by AEMO. These cost assumptions have been based on general industry knowledge available to AEMO.

Option 5: Demand management

Demand management, in the form of voluntary load curtailment, has the potential to decrease the involuntary load shedding that would otherwise be required during peak demand periods.

In this RIT-T analysis, it has been assumed that the non-network demand management has been spread between the two terminal station connection points that presented the highest expected load shedding (MWh) in the base case – do nothing – option. These two terminal stations have been selected because their combination is expected to provide the largest market benefit, since they are optimally placed to relieve the worst network limitations with least the load shedding required. Applying demand management to a wider area would result in diminishing returns because, although more demand reduction may be available, shedding load at these alternative locations would not off-load the worst network limitations to the same level.

The available non-network demand management support is assumed to be 5% of the 2013-14 10% POE forecast demand under the medium demand growth scenario, at each terminal station's transmission connection point. The 5% availability estimate is based on optimistic demand management contributions identified in other similar demand management assessments that AEMO has contributed to. Demand management is typically much lower than the 5% assumed (often as low as 2% of the maximum demand), however, AEMO has assumed the higher percentage in place of considering demand management availability at fewer locations.

Table 2 presents the available demand management location and non-network power support assumed in the assessment of Option 5.

Table 2: Available demand management location and support

Location	Demand reduction available (MW)
Ringwood Terminal Station 66 kV load	30 MW
Malvern Terminal Station 66 kV load	12 MW

Demand management cost assumptions have been based on general industry knowledge available to AEMO and information gathered from non-network service providers for similar demand management assessments that AEMO has been party to.

Table 3 describes and presents the assumed costs associated with demand management.

Table 3: Costs associated with demand management

Cost Type	Description	Cost
Establishment cost	**One-off cost** associated with implementing this option. The cost includes consultancy services to investigate the potential for demand management, to prepare plans, arrange support contracts and set up any systems for triggering and coordinating the demand response when it is required.	$80,000/MW of capacity required
Availability charge	**Regular payment** to the demand management provider for having support services in place, regardless of whether they are utilised.	A typical regular payment is expected to be in the range of $60,000 to

	The amount paid will depend on the types of customers involved in the scheme (i.e. whether the service is provided by a small number of large customers, or many small-to-medium customers).	$120,000/MW/year. In the absence of a demand management submission to the PSCR, or further information from potential demand management providers, a regular payment cost of $90,000/MW/year has been assumed.
Dispatch fee	Payment to the provider for reducing their demand when requested.	$900/MWh

Option 6: Local generation development

Development of new or expanded generation capacity, close to high demand locations within the Metropolitan Melbourne area, has the potential to reduce network asset loading during peak demand periods under system normal and outage conditions.

The reduction of network asset loading can create positive market benefits by reducing the amount of expected unserved energy that would otherwise be required to maintain network loading within asset limits.

In this RIT-T analysis, it has been assumed that the non-network local generation is installed at a single location within the network and has been optimally located at the terminal station connection point that presented the highest expected load shedding (MWh) in the base case – do nothing – option. This is expected to provide the largest market benefit because the new generator would be best placed to relieve the network limitation resulting in the most unserved energy.

A non-network generator of 75 MW is assumed for this RIT-T assessment. Based on the forecast cost of constraint under the base case – do nothing option, a generator of this size is expected to delay load shedding by approximately two years under the medium demand scenario.

Table 4 presents the available local generation location and non-network support assumed in the assessment of Option 6.

Table 4: Available local generation location and support

Location	Generator capacity (MW)
Ringwood Terminal Station 66 kV	75 MW

Local generation cost assumptions have been based on general industry knowledge available to AEMO and information gathered for similar non-network support assessments that AEMO has contributed to.

Table 5 describes the costs associated with distributed, or local, generation and presents the estimated local generation costs assumed for the RIT-T analysis.

Table 5: Costs associated with distributed generation

Cost Type	Description	Cost
Capital and establishment costs	Since a new generator would be required, the capital costs of the generation are included in the cost of the option. Gas generators generally have the lowest capital cost per MW of generation at the small-to-medium scale, and have therefore been assumed for this RIT-T assessment.	$1.6 million/MW
Availability charge	If an embedded generation option was implemented, the generation proponent may seek to recover the capital costs of the generator in the form of a negotiated, regular availability charge to the transmission network service provider (TNSP).	-

	However, since the capital costs of the generator are included in the option analysis, this charge has not been added to the cost of the option. It is instead assumed that whatever payment arrangement is negotiated covers the capital and establishment costs of the generator. Additionally, it is assumed that a generator's maintenance costs would be incorporated into their operating costs associated with power generation outside the scope of the network support agreement (i.e. they have not been attributed to the cost of the option under this RIT-T analysis because the generator proponent is assumed likely to use the generator in local power supply agreements).	
Dispatch fee	Payment to the generator for supplying power, to cover their short-run marginal costs.	$300/MWh

3.3 Credible options eliminated from the PSCR

Following publication of the PSCR for this RIT-T, and publication of past Victorian annual planning reports, AEMO has been working with SP AusNet to identify the exact cause of limitations on the East Rowville – Rowville 220 kV line. This review has resulted in an increased rating for this line.

It was identified by SP AusNet that a lower than applicable rating had been assigned to the East Rowville – Rowville 220 kV line. The rating was subsequently increased beyond any foreseeable system normal limitation, without requiring any actual network augmentation.

There were two credible network options mentioned in the PSCR that aimed to address the limitations associated with the East Rowville – Rowville 220 kV line thermal limitation:

- Option 2a – New 500/220 kV transformer at Rowville with upgrade of the existing East Rowville – Rowville 220 kV double circuit line.
- Option 2b – New 500/220 kV transformer at Rowville with installation of an underground 220 kV circuit between East Rowville – Rowville.

Utilising the amended rating provided by SP AusNet for the East Rowville – Rowville 220 kV line, there is no longer an identified need to reduce the expected loading on this line within the analysis period. Both of these network options have subsequently not been taken forward into the RIT-T modelling at this PADR stage.

4 Post Project Specification Consultation Report

4.1 Submissions to the PSCR

The first stage of the RIT-T process, the Project Specification Consultation Report (PSCR), was published on AEMO's website on 22 November 2011, with submissions from interested parties invited by 17 February 2012. No submissions to the PSCR were received.

4.2 Extension to the PADR publication period

AEMO intended on publishing this PADR report, the second stage in the RIT-T process, soon after the PSCR consultation process closed. However due to a reduction in forecast Victorian demand, AEMO decided to delay the detailed option analysis until after the terminal station demand forecasts where finalised and published on AEMO's website on 28 September 2012. Waiting for the terminal station demand forecasts has allowed for more robust option analysis based on up to date, realistic assumptions.

Because publication of this PADR extended beyond twelve months since the PSCR consultation period concluded, AEMO requested and was granted a six week extension period from the Australian Energy Regulator (AER) to publish this PADR by 31 March 2013.

5 Description of methodology

This section provides a summary of the methodology adopted for the RIT-T assessment for quantification of material market benefit from each credible option. It includes a description of the approach used for the market dispatch modelling, a description of the reasonable scenarios considered and a summary of the key assumptions.

5.1 Analysis period

The RIT-T analysis has been undertaken over the forecast period from 2013-14 through to 2022-23.

AEMO considers that an extension to the market modelling period beyond 2022-23 is neither credible nor warranted because limitations other than those associated with the identified need may erroneously skew the market modelling results in later years. Instead, in order to capture the end-effects associated with the life of the network assets or non-network solutions beyond 2022-23, the market benefits calculated for the final year (2022-23) have been held constant and applied as the assumed annual market benefit that would arise under the credible option in the future. This 'end-value' of annual market benefit has been assumed to apply for the remainder of the assumed asset life of each credible option. For each credible option assessed in this RIT-T, the assumed asset life is 40 years.

5.2 Market modelling

The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP can provide reasons why this methodology is not relevant.[8] AEMO considers that a market dispatch modelling methodology is relevant for this RIT-T application, and as a consequence has adopted this approach in order to calculate the market benefits associated with the credible options included in the RIT-T analysis.

The RIT-T requires many of the categories of market benefit to be calculated by comparing the 'state of the world' in the base case – do nothing option – (where no action is undertaken by AEMO) with the 'state of the world' with each of the credible options in place. The 'state of the world' is essentially a description of the NEM outcomes expected in each case.

In the case of this RIT-T assessment, the impact of each of the credible options on the operation of and outcomes in the NEM is such that the relevant comparison between the states of the world with and without each of the options can be appropriately estimated using market dispatch modelling.

In addition, the uncertainty associated with future NEM development and therefore the future 'state of the world' is addressed under the RIT-T by considering a number of 'reasonable scenarios' (discussed further in Section 5.4).

5.2.1 Market dispatch model

In order to calculate dispatch outcomes in the relevant 'state of the world', AEMO has undertaken market simulations using a market model which incorporates generation dispatch and market clearing processes to replicate the operation of the NEM. The model used for this RIT-T is the PROPHET model[9].

The market dispatch modelling methodology adopted is consistent with the further requirement in the RIT-T that the model must incorporate both:

[8] AER, Final Regulatory investment Test for Transmission, June 2010, version 1, paragraph 11, p.6.
[9] For details of the Prophet model see: http://www.iesys.com/ies/ProductsandServices/Prophetsuite.aspx Accessed February 2013.

- A realistic treatment of plant characteristics, including for example minimum generation levels and variable operating costs.
- A realistic treatment of the network constraints and losses.

The modelling uses a database in which each load and generator transmission connection point in Victoria is individually modelled. This allows load shedding requirements to be attributed to the specific transmission connection point that will best offload the limiting element with the minimum amount of load shedding required, where each limiting network element is represented by its own constraint equation.

The model includes a limited set of National Electricity Market Dispatch Engine (NEMDE) pre-dispatch system normal constraints so that inter-regional limitations are considered. This allows interconnector limits to be accurately considered, which can impact load sharing between the tie transformers supplying the 220 kV network. Intra-regional constraints, specifically around the Metropolitan Melbourne area, have been developed and modelled separately for each credible option assessed. Intra-regional constraint equations in regions other than Victoria have not been included in the model because they are not expected to be material to the analysis.

As described in Section 2.2, key constraint equations developed and modelled to represent the Metropolitan Melbourne area include the thermal loading limits of the:

- Cranbourne A1 500/220 kV transformer loading.
- Rowville A1 500/220 kV transformer loading.
- Rowville A2 500/220 kV transformer loading.
- South Morang H1 and H2 330/220 kV transformers.
- South Morang – Thomastown 220 kV line.
- Rowville – Ringwood 220 kV line.
- Ringwood – Thomastown 220 kV line.
- Rowville – Templestowe 220 kV line.
- Keilor – Thomastown 220 kV lines.
- Keilor A2 and A4 500/220 kV transformers.
- Moorabool A1 and A2 500/220 kV transformers.

The Prophet model has been run based on wind and temperature traces from 2009-10 data, demand traces grown from 2009-10 data, and on an assumption of Short Run Marginal Cost (SRMC) bidding behaviour of generators.

5.3 Key assumptions that drive market benefits

The following key assumptions drive the market benefits expected from relieving the supply capability limitations to Eastern Metropolitan Melbourne, and have been considered in development of reasonable scenarios for this RIT-T assessment:

- Forecast demand growth.
- Discount rate.
- Value of customer reliability (VCR).
- Generator installations, retirements and utilisation.
- Network element ratings.
- Generator unit outage rates.

Section 6.2 provides a further description of the approach adopted in quantifying each class of material market benefit.

5.3.1 Forecast demand growth

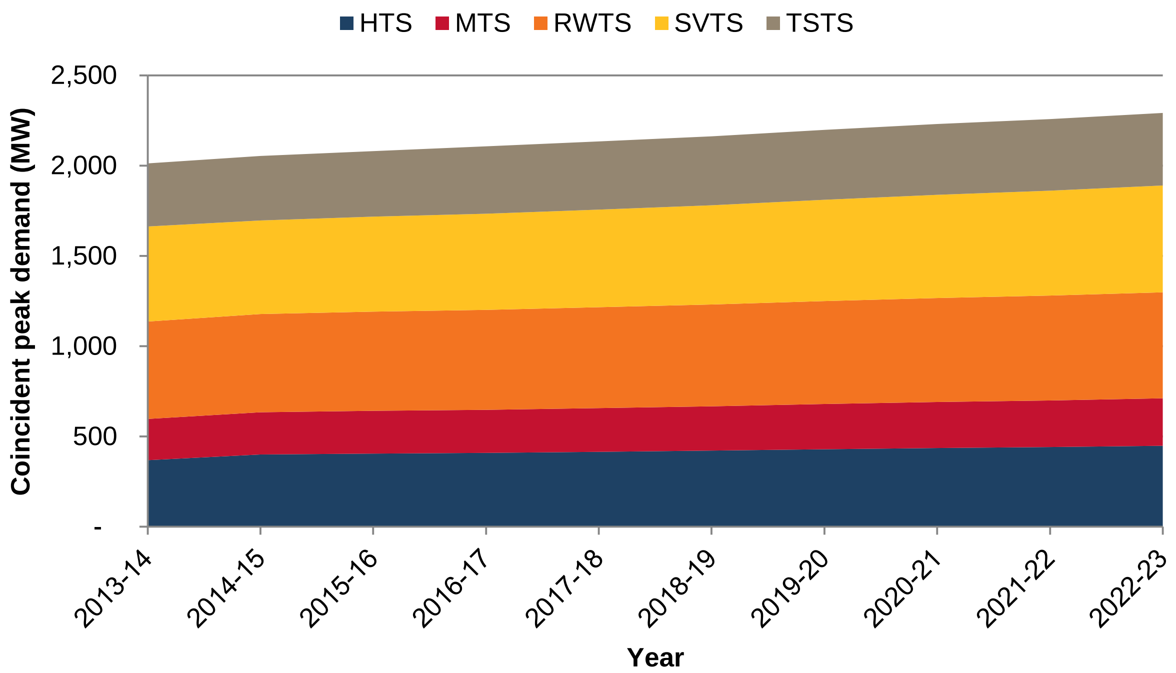
Although recent demand forecasts have shown a slower growth rate than has previously been experienced, electricity demand in the Metropolitan Melbourne is still continuing to grow. In particular, demand in Melbourne's south-eastern suburbs around Cranbourne is expected to increase due to an increase in housing developments in the area.

Figure 6 and Figure 7 show the forecast maximum demand growth of individual terminal stations in the Eastern Metropolitan Melbourne area. The forecasts presented are based on the medium economic growth scenario and represent the 10% probability of exceedence (POE) demand level, as presented in AEMO's Victorian Terminal Station Demand Forecasts 2012.[10] The forecasts are presented as the coincident (undiversified) peak demand, which assumes the peak demand of all terminal presented occur at the same time.

The terminal station demand forecasts were scaled down to align the system peak demand and annual energy forecasts of the Victorian region forecasts, as presented in AEMO's 2012 National Electricity Forecasting Report.[11]

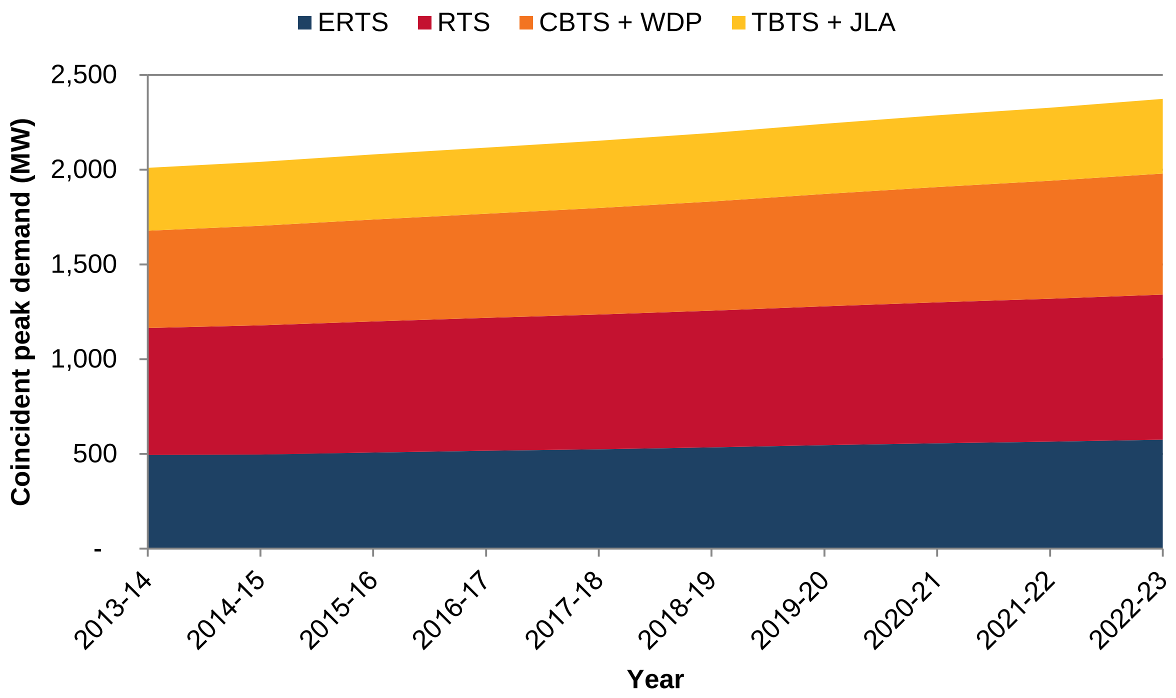
The demand forecasts applied under each scenario are presented in Appendix A.

Figure 6: Demand growth of stations supplied via Rowville No.3–No.4 220 kV bus group, medium demand growth rate scenario



[10] AEMO. "Victorian Terminal Station Demand Forecasts 2012". Available http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria. Accessed March 2013.
[11] AEMO. "2012 National Electricity Forecasting Report". Available http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Accessed March 2013.

Figure 7: Demand growth of stations supplied via Rowville No.1–No.2 220 kV bus group and Cranbourne, medium demand growth rate scenario



Uncertainty in the demand forecasts are accounted for by applying a 10% POE demand forecast and a 50% POE demand forecast and weighting them 30.4% and 69.6% respectively to calculate the expected unserved energy and generation dispatch variations. Low, medium and high demand growth rates have been assessed over the three scenarios described in Section 5.4, with each scenario weighted 33.3%.

5.3.2 Discount rate

A discount rate of 10% (real, pre-tax) has been adopted in undertaking the Net Present Value (NPV) analysis for each credible option. The discount rate represents a reasonable commercial discount rate, appropriate for the analysis of a private enterprise investment in the electricity sector, as required by the RIT-T.[12]

AEMO has tested the sensitivity of the results to changes in this discount rate assumption by applying a lower bound discount rate of 6% and an upper bound discount rate of 12%. The sensitivity of the RIT-T results to the discount rate assumption is presented in Section 6.3.4.

5.3.3 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.

The forecast Victorian VCR has recently been updated to $61,950/MWh (in 2013-14 Australian dollars), and has been used by AEMO to calculate the cost of expected unserved energy for this RIT-T.

Sensitivity values of ± 20% to the base have been applied, giving a low VCR of $49,560/MWh and a high VCR of $74,340/MWh.

The sensitivity of the RIT-T results to the VCR assumption is presented in Section 6.3.4.

[12] AER, Final Regulatory Investment Test for Transmission, June 2010, version 1, paragraph 14, p.6.

5.3.4 Generation expansion plan

The generation expansion plan modelled under each scenario is shown in Table 6, which has been based on connection enquiry and connection application information submitted to AEMO.

Because the identified need associated with this RIT-T is predominately driven by demand growth, each scenario has the same generation assumptions.

Table 6: Generation expansion plan modelled (Victoria)

Year	Project	Fuel Type	Capacity (MW)	Scenario 1	Scenario 2	Scenario 3
2013–14	Macarthur	Wind	420	✓	✓	✓
2014–15	Mt Gellibrand	Wind	232	✓	✓	✓
	Mt Mercer	Wind	131	✓	✓	✓
	Ryan Corner & Hawkesdale	Wind	234	✓	✓	✓
2015–16	Ararat	Wind	248	✓	✓	✓
2016–17	Ben More	Wind	120	✓	✓	✓
	Red Cliffs	Wind	200	✓	✓	✓
	Stockyard Hill	Wind	400	✓	✓	✓
	Penshurst	Wind	600	✓	✓	✓
2017–18	Lexton	Wind	47	✓	✓	✓
	Lal Lal (Yendon end)	Wind	80	✓	✓	✓
	Lal Lal (Elaine end)	Wind	48	✓	✓	✓
	Dundonnell	Wind	270	✓	✓	✓
	Darlington	Wind	350	✓	✓	✓
2018–19	Berry Bank	Wind	180	✓	✓	✓
	Crowlands	Wind	123	✓	✓	✓
	Moorabool	Wind	320	✓	✓	✓
	Mortlake and Minjah	Wind	485	✓	✓	✓
2019–20	Shaw River (Stage 1)	Gas	500	✓	✓	✓
2020–21	Tarrone	Gas	512	✓	✓	✓
2021–22	Mallee solar park	Solar	180	✓	✓	✓

5.3.5 Generation retirement plan

The generation retirement plan modelled under each scenario is shown in Table 7.

Table 7: Generation retirement plan modelled (Victoria)

Year	Station	Scenario 1	Scenario 2	Scenario 3
2014–15	Morwell G1	✓	✓	✓
	Morwell G2	✓	✓	✓
2015–16	Morwell G3	✓	✓	✓

5.3.6 Wind generation utilisation

The utilisation of existing and new wind farms can impact on transmission network loading levels by replacing other generation and altering the power flow patterns throughout the transmission network.

Due to the nature of the Metropolitan Melbourne network limitations, the utilisation of wind generation has a minimal impact on this RIT-T analysis. The same wind generation utilisation level, of approximately 33% of capacity during maximum demand periods, has therefore been applied in each of the scenarios assessed. This 33% utilisation factor comes from the actual wind generation utilisation recorded at Victorian maximum demand during the 2009-10 year, which was used as the base data for this analysis. AEMO also undertook a sensitivity assessment using 6.5% utilisation factor at peak demand. This assessment identified that wind generation utilisation is not material to the outcome of this RIT-T.

5.3.7 Modelling of hydro generation

Victorian hydroelectric generation is modelled by means of time-of-day bids based on a historical profile of Victorian hydroelectric dispatch for a typical year.

AEMO analysed historical data and determined that the average annual cost for all NEM hydro units was approximately $25. For calculating the future annual cost of hydro generation, the average annual cost for all NEM hydro units is increased, from this historical average annual cost of $25, by 80% of the carbon pricing each year. This escalation reflects that following the introduction of carbon pricing, the hydro units will continue to operate to maintain about the same reservoir levels as they did prior to the introduction of the carbon pricing. The increase also reflects that the average hydro cost would be higher with the carbon pricing, as the hydro units may incur higher electricity costs to pump water.

The annual hydro generation cost is calculated as follows:

Annual hydro generation cost = Annual hydro generation * hydro cost

Where:

Annual hydro generation is the total output from all hydro generating units in the NEM for a year (in MWh).

Hydro Cost is the annual average cost incurred from producing one additional MWh by all hydro generation in the NEM. This is approximated as $25 + 80% * Carbon Pricing (of that year).

5.3.8 Generation re-dispatch cost

Re-dispatch of generation is valued using the short run marginal cost (SRMC) of generation, including any price on carbon. The SRMC of generation applied for this RIT-T is derived from fuel cost projections prepared for the 2012 NTNDP[13].

5.3.9 Network element ratings

Supply from the 500 kV network is dependent on the thermal capacity of the Cranbourne A1 transformer and the Rowville A1 and A2 transformers. Each of the three transformers have a continuous rating of 1,000 MVA, a two hour rating of 1,250 MVA and a thirty minute rating of 1,500 MVA. Due to the high short-term overload capability available for these transformers, it is not uncommon for loading to be limited under normal operating conditions. In particular, the Cranbourne A1 and Rowville A1 transformers can limit supply under certain demand conditions with all network elements in service.

The transformer limits are constant in that they don't vary with generation or demand and are assumed unchanged irrespective of ambient temperature. The 220 kV transmission line ratings vary with ambient temperature and also have a fifteen minute contingency rating that varies depending on each circuit's pre-contingent loading level.

Although the fifteen minute ratings vary depending on each circuit's pre-contingent loading level, indicative ratings for the 220 kV transmission circuits modelled for this RIT-T are presented in Table 8.

Table 8: Indicative 15-minute transmission line ratings

Monitored network element	Indicative 15-minute rating at 40°C ambient temperature (MVA)
South Morang – Thomastown No.1 220 kV circuit	649
South Morang – Thomastown No.2 220 kV circuit	649
Thomastown – Ringwood 220 kV line	785
Rowville – Ringwood 220 kV line	825
Templestowe – Thomastown 220 kV line	770
East Rowville – Rowville No.1 220 kV line	857
East Rowville – Rowville No.2 220 kV line	857
Keilor – Thomastown No.1 220 kV line	585
Keilor – Thomastown No.2 220 kV line	689
Fishermans Bend – West Melbourne No.1 220 kV line	425
Fishermans Bend – West Melbourne No.2 220 kV line	425
Keilor – West Melbourne No.1 220 kV circuit	835
Keilor – West Melbourne No.2 220 kV circuit	835

5.4 Description and weighting of reasonable scenarios

The RIT-T analysis needs to incorporate a number of different reasonable scenarios, which are used to estimate the market benefits associated with each credible option. The RIT-T states that the number and choice of reasonable scenarios must be appropriate to the credible options under consideration. The choice of reasonable scenarios must reflect any variables or parameters that:

[13] ACIL Tasman. "Fuel cost projections – Updated natural gas and coal outlook for AEMO modelling". Available http://www.aemo.com.au/Electricity/Planning/Related-Information/2012-Planning-Assumptions. Accessed March 2013.

- Are likely to affect the ranking of the credible options, where the identified need is reliability corrective action.
- Are likely to affect the ranking of the credible options, or the sign of the net economic benefits of any of the credible options, for all other identified needs.

To consider the identified key factors that drive market benefits, AEMO has adopted the following three scenarios in undertaking the RIT-T analysis presented in this PADR:

- Scenario 1: Low demand growth scenario (33.3%).
- Scenario 2: Medium demand growth scenario (33.3%).
- Scenario 3: High demand growth scenario (33.3%).

These three scenarios reflect a range of different economic growth scenarios and forecast electricity demand levels, as outlined in Section 5.3, which are considered to have the potential to affect the market modelling outcomes of this RIT-T.

The parameters adopted under scenario are summarised in Table 9.

Table 9: Summary of parameters under each reasonable scenario

Drivers	Scenario 1	Scenario 2	Scenario 3
Economic growth	Low	Medium	High
Demand growth	Low	Medium	High
Carbon price	Treasury-Core	Treasury-Core	Treasury-Core
Rooftop PV	Moderate	Moderate	Moderate
Weighting	33.3%	33.3%	33.3%

The carbon price assumed is based on the Federal Government's Clean Energy Policy, adjusted for CPI[14]. Rooftop PV contribution derives from AEMO's National Electricity Forecasting Report[15].

5.5 Classes of market benefits not expected to be material

In the PSCR AEMO noted that the following classes of market benefit are unlikely to be material for this RIT-T analysis:

- Differences in the timing of transmission investment.
- Changes in ancillary services costs.
- Option value.
- Competition benefits.

In addition to these categories, AEMO has also identified that changes in costs for parties other than the TNSP is not a material market benefit category for the purposes of this RIT-T.

The reasons for these classes of market benefits being considered not material are set out below.

Differences in the timing of transmission investment

[14] Australinan Government The Treasury. "Strong Growth, Low Pollution – Modelling a Carbon Price". Available http://archive.treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp. Accessed Macrh 2013.

[15] AEMO. "2012 National Electricity Forecasting Report". Available http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012. Accessed March 2013.

The credible options to address the identified need are not expected to change the timing of any other transmission investment currently being considered. AEMO therefore considers this class of benefit to not be material to the outcome of the RIT-T assessment and has not attempted to estimate any additional transmission investment market benefit for this RIT-T assessment.

Changes in ancillary services costs

There is no expected change to the costs of Frequency Control Ancillary Services (FCAS), Network Control Ancillary Services (NCAS) or System Restart Ancillary Services (SRAS) as a result of the options being considered. These costs are therefore not material to the outcome of the RIT-T assessment.

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.[16]

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 considers this class of benefit to not be material to the outcome of the RIT-T assessment and has not attempted to estimate any additional option value market benefit for this RIT-T assessment.

Competition benefits

Increasing the supply capability to Eastern Metropolitan Melbourne will reduce the reliance on local generation and increase the ability of generation from the rest of the NEM to supply the bulk demand areas around Metropolitan Melbourne. The extent that this increase in competition results in a different dispatch pattern over and above that associated with a variation in fuel costs is expected to be negligible.

Assessment of competition benefits would also require additional modelling, such as the inclusion of game theory bidding or similar, which would lead to substantial increases in the complexity and cost of the RIT-T assessment. Such increased complexity is not warranted given the negligible market benefits expected from any additional market competition realised. AEMO therefore considers this class of benefit to not be material to the outcome of the RIT-T assessment and has not attempted to estimate any additional market competition benefit for this RIT-T assessment.

Changes in costs for other parties

A non-network local generator installation may reduce the requirement for future remote generation. Additionally, an embedded generator may lead to changes in sub-transmission and distribution network investment requirements.

Without understanding and modelling sub-transmission and distribution network constraints in the Eastern Metropolitan Melbourne area, the potential additional benefits can’t be identified. AEMO considers that modelling sub-transmission and distribution network constraints in the area would lead to substantial increases in the complexity and cost of the RIT-T assessment beyond the likely additional market benefits that could be realised. AEMO therefore considers this class of benefit to not be material to the outcome of the RIT-T assessment and has therefore not attempted to estimate any additional changes in costs for other parties.

16 AER. “Final Regulatory Investment Test for Transmission Application Guidelines”, p.39 and p.75. Available http://www.aer.gov.au. Accessed November 2011.

6 Detailed option assessment

This section summarises the results of the NPV analysis for each of the credible options discussed in Section 3. Appendix B provides more detailed results of the scenario and sensitivity analysis.

The NER requires that the PADR set out a detailed description of the methodologies used in quantifying each class of material market benefit and cost, together with the results of the NPV analysis, and accompanying explanatory statement regarding the results. This section therefore discusses how each of the costs and material categories of market benefits have been calculated, before presenting and discussing the market benefit results across each of the credible options.

6.1 Quantification of costs for each option

The capital costs for the network options have been based on cost estimates provided by SP AusNet, prepared utilising their in-house estimation. The costs have been indexed according to Melbourne CPI to represent them in 2013-14 dollars. Operating costs for the network options have been assumed to be 2% of the option's capital cost per annum. These planning estimates have an accuracy range of ±30%.

The indicative costs for the demand management provisions of Option 5 and the local generation of Option 6 have been estimated by AEMO. The indicative costs for each of the non-network options have been based on general industry knowledge available to AEMO, including submissions to other RIT-T assessments and discussions with non-network and small generator providers.

Table 10 presents the costs of each credible option, which were further detailed in Section 3.

Table 10: Base costs of credible options (2013-14 $M)

Credible Option	Components	Capital cost ($M)	Operating cost ($M)	Total project cost ($M)
Option 1	Cranbourne A2 transformer installation and Hazelwood – Rowville 500 kV line connection at Cranbourne	69	14	83
Option 2	Rowville A3 500/220 kV transformer installation	43	8	51
Option 3	Ringwood 500 kV switchyard establishment and Ringwood A1 500/220 kV transformer installation	88	17	105
Option 4	Templestowe 500 kV switchyard establishment and Templestowe A1 500/220 kV transformer installation	152	30	182
Option 5	Demand management of 30 MW at Ringwood 66 kV bus and 12 MW Malvern 66 kV bus	3	37	40
Option 6	Local generator installation of 75 MW at Ringwood 66 kV bus	120	-	120

6.2 Quantification of classes of material market benefit for each credible option

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.[17]

To measure the increase in net market benefit, AEMO analysed the classes of market benefit required for consideration under paragraph 5 of the RIT-T, with the exception of those classes which are considered to be non-material for this RIT-T assessment, as outlined in Section 5.5.[18]

The remaining classes of market benefit which have been quantified for this assessment are:

- Changes in involuntary load shedding.
- Changes in voluntary load shedding.
- Changes in generator fuel consumption, arising through different patterns of generation dispatch.
- Changes in network losses.

Outside of those specified in the RIT-T itself, there has been no additional categories of market benefit identified as relevant for this RIT-T assessment.

6.2.1 Changes in involuntary load shedding

Increasing supply capability to Eastern Metropolitan Melbourne reduces the quantity and duration of load shedding required to ensure network loading remains within asset limits. Similarly, voluntary load curtailment, through non-network demand management, reduces the amount of load shedding required.

AEMO has quantified the impact of changes in involuntary load shedding associated with the implementation of each option via the Prophet modelling. Specifically, the Prophet modelling estimates the MWh of expected unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to the estimated level of USE.

6.2.2 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load, once pool prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects pool price outcomes, and in particular results in pool prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

The Prophet modelling incorporates voluntary load curtailment as part of its suite of dispatch options. As a consequence, the market benefit associated with changes in voluntary load curtailment is already reflected in the difference in dispatch cost outcomes discussed in Section 6.2.3.

AEMO notes that the level of voluntary load curtailment currently present in the NEM is limited.

Additionally, a demand-side reduction credible option will lead to an increase in the amount of voluntary load curtailment, in place of involuntary load shedding, and the costs associated with this are presented as an increase in dispatch cost.

17 AEMC. "National Electricity Rules". Version 46, November 2011, Clause 5.6.5B (b). Available http://www.aemc.gov.au. Accessed November 2011.
18 AER. "Final Regulatory Investment Test for Transmission". Version 1, June 2010, 4pp. Available http://www.aer.gov.au. Accessed November 2011.

6.2.3 Changes in generator fuel consumption

The network limitations identified are predominantly driven by increasing demand; however, generation connected within the 220 kV network can offload the transmission assets of concern. In particular, Yallourn Power Station output significantly reduces loading on the Rowville and Cranbourne transformers, while Somerton, Newport and Laverton North power stations can also provide some loading relief to these assets.

The Prophet modelling incorporates the expected changes in generator fuel consumption associated with each credible option by calculating the total dispatch cost under each state of the world. Specifically, the generation dispatch cost under each credible option and state of the world has been considered in comparison with the generation dispatch cost under the base case, and included in the total cost of constraint to quantify the market benefit associated with changes in generation fuel consumption.

6.2.4 Changes in network losses

The market modelling undertaken by AEMO has taken into account the change in network losses that may be expected to occur as a result of the implementation of any of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

An increase in network losses represents a negative market benefit (i.e. a market cost), while a reduction in losses represents a positive market benefit.

The market benefit of the change in network losses has inherently been included in the market modelling results. These benefits are realised by the change in constraint equations which have been separately modelled for each credible option assessed.

6.3 Net Present Value results

This section summarises the results of the net present value (NPV) analysis. It first presents the annual market impact of each credible option assessed, summarises the gross market benefits and then presents the net market benefits of each credible option, followed by a sensitivity assessment to key assumptions, including discount rate, capital option cost and VCR.

6.3.1 Annual market impact

This section shows the market impact under the base case and each credible option assessed, assuming that the credible option is in place from year one (2013-14).

The tables show:

- Max load and energy at risk, which is the MW load shedding required to avoid the network limitation, and the resulting unserved energy under 10% POE demand conditions and the highest impacting scenario.
- Expected unserved energy, which is a portion of the energy at risk after taking into account the probability of the limitation occurring, including the probability of the demand conditions occurring and weighted across the reasonable scenarios considered.
- Limitation cost, which is the cost of the expected unserved energy, obtained by multiplying the expected unserved energy by the VCR.

6.3.1.1 Base case – Do Nothing

Due to transmission network limitations identified in Section 2.2, if no other action is taken involuntary load shedding will be required from 2015-16 to maintain network thermal loading levels within network capabilities.

The forecast market impact under the base case – do nothing – option is presented in Table 11.

Table 11: Forecast market impact under base case

Year	Max load at risk (MW)	Max energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ '000)
2013–14	-	-	-	-
2014–15	-	-	-	-
2015–16	62	100	10	626
2016–17	136	299	30	1,875
2017–18	258	761	78	4,854
2018–19	294	1,193	128	7,949
2019–20	763	3,202	362	22,401
2020–21	1,077	5,330	626	38,773
2021–22	1,564	11,005	1,359	84,169
2022–23	1,962	17,952	2,464	152,614

6.3.1.2 Option 1 – Cranbourne 500/220 kV transformer installation and 500 kV line connection

Installation of the Cranbourne 500/220 kV transformer and connection of the Hazelwood – Rowville 500 kV line at Cranbourne increases the thermal supply capacity into Eastern Metropolitan Melbourne, thereby reducing the required involuntary load shedding required to maintain network thermal loading levels within network capabilities.

The forecast market impact under Option 1 is presented in Table 12.

Table 12: Forecast market impact under Option 1

Year	Max load at risk (MW)	Max energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ '000)
2013–14	-	-	-	-
2014–15	-	-	-	-
2015–16	-	-	-	-
2016–17	-	-	-	-
2017–18	79	122	12	764
2018–19	73	156	16	979
2019–20	284	969	109	6,743
2020–21	452	1,680	216	13,398
2021–22	576	3,242	434	26,866
2022–23	709	5,452	807	49,965

If Option 1 was implemented, involuntary load shedding would be required from 2017-18 to maintain network thermal loading levels within network capabilities.

This option incorporates two classes of market benefit. It reduces the amount of involuntary load shedding by providing additional network capacity. Changes in network losses are also accounted for by recalculation of network constraint equations for each alternative option assessed. This recalculation of network constraint equations results in updated participation factors for each network limit, and thereby alternative network flows, inherently accounting for changes in network losses.

6.3.1.3 Option 2 – Rowville 500/220 kV transformer installation

Installation of a new Rowville 500/220 kV transformer increases the thermal supply capacity into Eastern Metropolitan Melbourne, thereby reducing the required involuntary load shedding required to maintain network thermal loading levels within network capabilities.

The forecast market impact under Option 2 is presented in Table 13.

Table 13: Forecast market impact under Option 2

Year	Max load at risk (MW)	Max energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ ‘000)
2013–14	-	-	-	-
2014–15	-	-	-	-
2015–16	-	-	-	-
2016–17	-	-	-	-
2017–18	-	-	-	-
2018–19	-	-	-	-
2019–20	52	143	14	895
2020–21	69	250	25	1,569
2021–22	186	1,027	109	6,753
2022–23	289	2,260	263	16,296

With implementation of Option 2, it is anticipated that any involuntary load shedding will be moved out to 2019-20 to maintain network thermal loading levels within network capabilities.

This option incorporates two classes of market benefit. It reduces the amount of involuntary load shedding by providing additional network capacity. Changes in network losses are also accounted for by recalculation of network constraint equations for each alternative option assessed. This recalculation of network constraint equations results in updated participation factors for each network limit, and thereby alternative network flows, inherently accounting for changes in network losses.

6.3.1.4 Option 3 – Ringwood 500 kV switchyard establishment and 500/220 kV transformer installation

Establishment of a new 500 kV switchyard at Ringwood and installation of a new Ringwood 500/220 kV transformer increases the thermal supply capacity into Eastern Metropolitan Melbourne, thereby reducing the required involuntary load shedding required to maintain network thermal loading levels within network capabilities.

The forecast market impact under Option 3 is presented in Table 14.

Table 14: Forecast market impact under Option 3

Year	Max load at risk (MW)	Max energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ ‘000)
2013–14	-	-	-	-
2014–15	-	-	-	-
2015–16	-	-	-	-
2016–17	-	-	-	-
2017–18	-	-	-	-
2018–19	-	-	-	-
2019–20	-	-	-	-
2020–21	27	56	6	352
2021–22	133	554	56	3,479
2022–23	214	1,552	175	10,821

If Option 3 was implemented, it is anticipated that any involuntary load shedding would not be required until 2020-21 to maintain network thermal loading levels within network capabilities.

This option incorporates two classes of market benefit. It reduces the amount of involuntary load shedding by providing additional network capacity. Changes in network losses are also accounted for by recalculation of network constraint equations for each alternative option assessed. This recalculation of network constraint equations results in updated participation factors for each network limit, and thereby alternative network flows, inherently accounting for changes in network losses.

6.3.1.5 Option 4 – Templestowe 500 kV switchyard establishment and 500/220 kV transformer installation

Establishment of a new 500 kV switchyard at Templestowe and installation of a new Templestowe 500/220 kV transformer increases the thermal supply capacity into Eastern Metropolitan Melbourne, thereby reducing the required involuntary load shedding required to maintain network thermal loading levels within network capabilities.

The forecast market impact under Option 4 is presented in Table 15.

Table 15: Forecast market impact under Option 4

Year	Max load at risk (MW)	Max energy at risk (MWh)	Expected unserved energy (MWh)	Limitation cost ($ '000)
2013–14	-	-	-	-
2014–15	-	-	-	-
2015–16	-	-	-	-
2016–17	-	-	-	-
2017–18	-	-	-	-
2018–19	-	-	-	-
2019–20	-	-	-	-
2020–21	8	8	1	48
2021–22	129	453	46	2,844
2022–23	228	1,316	141	8,755

Implementation of Option 4 would, it is anticipated, move any required involuntary load shedding out until 2020-21, at which point come would be required to maintain network thermal loading levels within network capabilities.

This option incorporates two classes of market benefit. It reduces the amount of involuntary load shedding by providing additional network capacity. Changes in network losses are also accounted for by recalculation of network constraint equations for each alternative option assessed. This recalculation of network constraint equations results in updated participation factors for each network limit, and thereby alternative network flows, inherently accounting for changes in network losses.

6.3.1.6 Option 5 – Non-network demand management establishment

In this RIT-T analysis, it has been assumed that the non-network demand management has been spread between the two terminal station connection points that presented the highest expected load shedding (MWh) in the base case – do nothing – option. The available non-network demand management support is assumed to be 5% of the 2013-14 10% POE forecast demand under the medium demand growth scenario, at each terminal station's transmission connection.

The utilisation payment (dispatch fee) to the demand management service provider is incorporated in the dispatch cost presented in Table 16, thereby increasing the total dispatch cost compared to the base case but reducing the reported expected unserved energy, which only includes involuntary load shedding resulting under this option.

Table 16: Forecast market impact under Option 5

Year	Max load at risk (MW)	Max energy at risk (MWh)	Expected unserved energy (MWh)	Dispatch cost ($ '000)	Limitation cost ($ '000)
2013–14	-	-	-	-	-
2014–15	-	-	-	-	-
2015–16	7	7	1	8	51
2016–17	78	171	17	11	1,085
2017–18	159	480	49	26	3,039

2018–19	237	776	79	44	4,913
2019–20	684	2,369	262	90	16,295
2020–21	990	4,214	488	124	30,364
2021–22	1,521	9,155	1,090	242	67,776
2022–23	1,857	15,686	2,087	340	129,604

If Option 5 was implemented, it is anticipated that involuntary load shedding would still be required in 2015-16 to maintain network thermal loading levels within network capabilities, however the amount of load shedding would be reduced from the base case; thereby still reducing the constraint cost to the market.

This option incorporates two class of market benefit. It reduces the amount of involuntary load shedding and replaces it with lower cost voluntary load curtailment (represented above as the dispatch cost).

6.3.1.7 Option 6 - Non-network local generation installation

In this RIT-T analysis, it has been assumed that the non-network local generation in installed at a single point in the network and has been optimally located at the terminal station connection point that presented the highest expected load shedding (MWh) in the base case – do nothing – option. This is expected to provide the most market benefit because the new generator would be best placed to relieve the network limitation resulting in the most unserved energy.

The utilisation payment (dispatch fee) is incorporated in the dispatch cost presented in Table 17, thereby increasing the total dispatch cost compared to the base case but reducing the expected unserved energy.

Table 17: Forecast market impact under Option 6

Year	Max load at risk (MW)	Max energy at risk (MWh)	Expected unserved energy (MWh)	Dispatch cost ($ ‘000)	Limitation cost ($ ‘000)
2013–14	-	-	-	-	-
2014–15	-	-	-	-	-
2015–16	-	-	-	3	3
2016–17	51	87	9	6	543
2017–18	131	369	37	12	2,274
2018–19	187	508	51	23	3,138
2019–20	641	1,952	209	46	12,723
2020–21	1,019	3,435	394	70	23,911
2021–22	1,463	7,959	930	129	56,409
2022–23	1,880	14,078	1,831	190	111,033

If Option 6 was implemented, it is anticipated that any involuntary load shedding would be moved out to 2016-17 to maintain network thermal loading levels within network capabilities.

This option incorporates two classes of market benefit. It reduces the amount of involuntary load shedding and increases the market dispatch cost by operating the new generator.

6.3.2 Gross market benefits

Table 18 summarises the gross market benefit, in NPV terms, of each of the six credible options included in the RIT-T analysis. The gross market benefit is the sum of each of the individual categories of material market benefit (both positive and negative) and is calculated by comparing the market cost under each credible option with the market cost under the base case – do nothing – option.

As discussed earlier, the gross market benefit of each option has been calculated for three reasonable scenarios. The results of each option under the scenarios have been weighted to derive the overall market benefit for each credible option.

Table 18: Gross market benefits for each credible option (NPV, $M)

Option		Scenario 1: Low demand growth	Scenario 2: Medium demand growth	Scenario 3: High demand growth	**Weighted Gross Benefits**
	Scenario weighting	33.3%	33.3%	33.3%	
Option 1	Cranbourne 500/220 kV transformer and Hazelwood – Rowville 500 kV line connection	11	222	1061	**431**
Option 2	Rowville 500/220 kV transformer	22	325	1374	**573**
Option 3	Ringwood 500 kV switchyard and 500/220 kV transformer	22	336	1430	**596**
Option 4	Templestowe 500 kV switchyard and 500/220 kV transformer	22	343	1448	**604**
Option 5	Non-network demand management	17	132	400	**103**
Option 6	Non-network local generator	9	78	221	**183**

6.3.3 Net market benefits

Table 19 summarises the net market benefit in NPV terms for each credible option. The net market benefit is the gross market benefit, weighted across all scenarios, minus the cost to implement the credible option, all in present value terms.

The table also shows the corresponding ranking of each option under the RIT-T, with the options ranked from 1 to 6 in descending order of net market benefit.

Table 19: Net market benefit for each credible option (PV, $M)

Option	Description	Costs	Gross market benefit	Net market benefit	Ranking under RIT-T
Option 1	Cranbourne 500/220 kV transformer	83	431	348	4
Option 2	**Rowville 500/220 kV transformer**	**51**	**573**	**522**	**1**
Option 3	Ringwood 500 kV switchyard and 500/220 kV transformer	105	596	491	2
Option 4	Templestowe 500 kV switchyard and 500/220 kV transformer	182	604	422	3
Option 5	Non-network demand management	40	103	63	6
Option 6	Non-network local generator	120	183	63	5

Table 19 shows that all of the credible options considered have a positive net market benefit. This means that all of the options are ranked higher than the base case – do nothing – option, and could be expected to deliver an overall net benefit to the market.

The results also show that installation of a new 500/220 kV transformer at Rowville Terminal Station delivers the greatest net market benefits, despite having lower gross market benefits than Option 3 and Option 4, due to its high capacity but low cost.

6.3.4 Sensitivity analysis

AEMO has performed a series of sensitivity studies on the base results presented. The sensitivity analysis considers and allows for changes in relation to the:

- Discount rate applied.
- Capital augmentation costs of each credible option assessed.
- Value of customer reliability (VCR) considered.

Table 20 presents the Net Present Value of each credible option, relative to the base case - do nothing – option, under each of the sensitivities considered.

Table 20: Net Present Value of Net Market Benefit ($ M)

Sensitivity	Discount Rate		Capital Cost		VCR	
	6%	12%	+30%	-30%	+20%	-20%
Option 1 – Cranbourne 500/220 kV transformer installation and Hazelwood – Rowville 500 kV line cut-in at Cranbourne	789	233	323	373	434	262
Option 2 – Rowville 500/220 kV transformer installation	**1,108**	**370**	**507**	**538**	**637**	**408**
Option 3 – Ringwood 500 kV switchyard establishment and 500/220 kV transformer installation	1,100	332	460	523	610	372
Option 4 – Templestowe 500 kV switchyard and 500/220 kV transformer installation	1,040	261	367	477	543	301
Option 5 – Non-network demand management	163	36	51	75	84	42
Option 6 – Non-network local generator	244	15	27	99	100	26

The results show that Option 2 is expected to maximise the net market benefits under all sensitivities considered, confirming that installation of a new (third) Rowville 500/220 kV transformer is the preferred option.

7 Proposed preferred option

The previous section presented the results of the NPV analysis conducted for this RIT-T assessment.

The NER requires that the PADR include the identification of the preferred option under the RIT-T. This must be the option with the greatest net market benefit and which is therefore expected to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

The RIT-T analysis, discussed in Section 6.3, demonstrates that Option 2 is the highest ranked option under all scenarios, delivering the largest net market benefit compared to the other credible options considered.

The preferred option is therefore installation of a new (third) 500/220 kV transformer at Rowville Terminal Station. This option has a positive net market benefit of $522 million and satisfies the RIT-T.

Table 21 presents the annualised cost-benefit assessment of the preferred option, for the ten-year period from 2013-14. This shows that the optimal time for augmentation, being the year where the annualised gross market benefits associated with augmenting outweigh the annualised cost to implement the preferred option, is 2018-19.

Table 21: Annualised cost-benefit assessment of preferred option

Year	Market impact under base case - do nothing option ($ '000)	Market impact under Option 2 – Rowville 500/220 kV transformer installation ($ '000)	Annualised gross market benefits ($ '000)	Annualised cost of preferred option ($ '000)	Net market benefits of preferred option annualised ($ '000)
2013–14	-	-	-	5,215	- 5,215
2014–15	-	-	-	5,215	- 5,215
2015–16	626	-	626	5,215	- 4,589
2016–17	1,875	-	1,875	5,215	- 3,340
2017–18	4,854	-	4,854	5,215	- 361
2018–19	7,949	-	7,949	5,215	2,734
2019–20	22,401	895	21,506	5,215	16,291
2020–21	38,773	1,569	37,204	5,215	31,989
2021–22	84,169	6,753	77,416	5,215	72,201
2022–23	152,614	16,296	136,318	5,215	131,103

The estimated commissioning date of this option is November 2018. In order to achieve this commissioning date, the estimated construction timetable is:

- Contestable works tender process underway: July 2014.
- Project agreements executed: March 2015.
- Proposed preferred option assets on order: May 2015.

- Site works and asset installation underway: May – September 2018.
- Commissioning tests underway: October 2018.
- New assets commissioned and in service: November 2018.

The capital cost of the proposed preferred option is estimated at $43 million (in present value terms) over the life of the project, with positive net benefits commencing from 2018-19. The total project cost, inclusive of operating costs estimated at 2% of the capital cost per annum ($8 million), is $51 million.

The technical characteristics of this option have been set out in Section 3. In compliance with the NER provisions, AEMO notes that this option is not expected to have any material inter-regional impact.

Appendix A - Terminal Station Demand Forecasts

Table 22 through to Table 27 presents the undiversified 10% POE and 50% POE terminal station demand forecasts under the Low, Medium and High scenarios analysed in this RIT-T PADR.

Table 22: Low economic growth 10% POE maximum demand forecasts (undiversified)

	2013–14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
CBTS 66 kV + WDP 220 kV	510	520	530	539	551	562	576	589	601	616
ERTS 66kV	491	490	499	506	513	521	529	537	543	553
HTS 66 kV	360	389	392	394	399	404	409	414	417	424
JLA 220 kV	35	35	34	34	34	34	34	34	33	33
MTS 22 kV	39	39	39	40	40	40	40	41	41	41
MTS 66 kV	187	191	193	193	196	198	201	204	206	210
RTS 22 kV	79	80	82	83	84	86	87	88	89	91
RTS 66 kV	595	603	608	614	620	626	633	639	645	654
RWTS 22 kV	93	93	93	93	93	93	93	93	94	94
RWTS Bus 1/3 66 kV	304	306	308	309	312	314	317	319	322	326
RWTS Bus 2/4 66 kV	222	223	223	224	226	227	227	228	229	231
SVTS 66 kV	519	509	514	518	525	531	540	548	554	564
TBTS 66 kV	296	300	305	309	314	319	327	333	338	347
TSTS 66 kV	347	353	357	365	369	372	375	378	380	385

Table 23: Low economic growth 50% POE maximum demand forecasts (undiversified)

	2013–14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
CBTS 66 kV + WDP 220 kV	455	464	472	480	490	499	510	521	530	542
ERTS 66kV	455	454	462	469	475	481	487	492	497	507
HTS 66 kV	333	361	366	369	375	380	385	389	393	400
JLA 220 kV	35	35	34	34	34	34	34	34	33	33
MTS 22 kV	32	33	33	33	34	34	35	35	36	36
MTS 66 kV	169	172	173	172	174	175	176	177	177	180
RTS 22 kV	73	74	76	77	78	79	80	82	83	84
RTS 66 kV	550	557	561	565	571	576	581	587	591	599
RWTS 22 kV	80	81	81	81	82	82	82	83	83	84
RWTS Bus 1/3 66 kV	248	249	251	252	254	256	258	259	261	264
RWTS Bus 2/4 66 kV	196	197	198	198	199	200	201	202	202	204
SVTS 66 kV	479	470	475	478	484	488	494	499	503	513
TBTS 66 kV	273	277	281	284	289	293	298	303	307	314
TSTS 66 kV	304	309	313	320	323	325	327	329	331	335

Table 24: Medium economic growth 10% POE maximum demand forecasts (undiversified)

	2013–14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
CBTS 66 kV + WDP 220 kV	519	531	544	555	568	582	599	615	629	646
ERTS 66kV	501	503	514	524	532	542	554	564	573	584
HTS 66 kV	368	399	404	408	414	420	428	435	440	447
JLA 220 kV	36	36	36	36	36	36	36	36	36	36
MTS 22 kV	40	40	41	41	41	42	42	43	43	44
MTS 66 kV	190	196	198	199	203	206	211	215	217	222
RTS 22 kV	81	83	84	86	88	89	91	93	95	96
RTS 66 kV	608	619	627	635	643	652	662	672	681	690
RWTS 22 kV	95	95	96	96	96	97	98	98	99	99
RWTS Bus 1/3 66 kV	310	313	317	320	323	327	332	336	339	344
RWTS Bus 2/4 66 kV	227	228	230	232	234	236	238	240	242	244
SVTS 66 kV	530	522	530	536	544	553	565	576	585	596
TBTS 66 kV	302	308	314	319	326	333	342	350	357	366
TSTS 66 kV	354	362	368	378	383	387	392	397	402	407

Table 25: Medium economic growth 50% POE maximum demand forecasts (undiversified)

	2013–14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
CBTS 66 kV + WDP 220 kV	463	474	484	494	505	517	531	543	555	568
ERTS 66kV	465	466	477	485	493	501	511	518	525	535
HTS 66 kV	340	371	377	382	389	396	403	410	416	423
JLA 220 kV	36	36	36	36	36	36	36	36	36	36
MTS 22 kV	33	34	34	34	35	36	36	37	38	38
MTS 66 kV	173	177	179	179	181	182	185	186	187	191
RTS 22 kV	75	76	78	79	81	83	84	86	87	89
RTS 66 kV	562	571	579	586	593	601	609	617	625	633
RWTS 22 kV	82	83	84	84	85	85	86	87	88	88
RWTS Bus 1/3 66 kV	253	256	259	261	264	267	270	273	276	279
RWTS Bus 2/4 66 kV	200	202	204	205	207	209	210	212	214	215
SVTS 66 kV	490	482	490	495	502	509	517	525	532	542
TBTS 66 kV	279	284	290	295	300	306	312	318	324	332
TSTS 66 kV	311	318	323	331	335	339	343	346	350	354

Table 26: High economic growth 10% POE maximum demand forecasts (undiversified)

	2013–14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
CBTS 66 kV + WDP 220 kV	530	545	560	573	586	601	620	637	655	673
ERTS 66kV	514	519	533	543	552	563	577	588	601	612
HTS 66 kV	377	411	418	423	429	436	445	453	461	468
JLA 220 kV	38	38	38	38	38	38	38	38	38	38
MTS 22 kV	41	42	42	42	43	43	44	45	45	46
MTS 66 kV	195	202	205	207	211	214	219	224	227	232
RTS 22 kV	83	85	87	89	91	93	95	97	99	101
RTS 66 kV	623	638	649	658	667	677	689	699	713	723
RWTS 22 kV	97	98	99	100	100	101	102	102	104	104
RWTS Bus 1/3 66 kV	318	323	328	332	335	340	345	350	356	360
RWTS Bus 2/4 66 kV	232	235	238	241	243	245	247	250	253	255
SVTS 66 kV	543	538	548	556	564	574	588	599	612	624
TBTS 66 kV	310	317	325	331	338	345	355	364	374	383
TSTS 66 kV	363	373	381	392	397	402	408	414	421	427

Table 27: High economic growth 50% POE maximum demand forecasts (undiversified)

	2013–14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23
CBTS 66 kV + WDP 220 kV	473	486	499	510	521	534	549	563	578	592
ERTS 66kV	477	481	494	504	512	521	532	541	551	562
HTS 66 kV	348	382	391	396	404	412	420	427	436	443
JLA 220 kV	38	38	38	38	38	38	38	38	38	38
MTS 22 kV	35	35	36	36	36	37	38	39	40	40
MTS 66 kV	178	183	185	185	188	189	192	194	197	200
RTS 22 kV	76	79	81	83	84	86	88	90	92	93
RTS 66 kV	576	589	599	608	615	624	634	643	655	664
RWTS 22 kV	84	86	87	87	88	89	90	91	92	93
RWTS Bus 1/3 66 kV	259	264	268	271	274	277	281	284	289	293
RWTS Bus 2/4 66 kV	205	208	211	213	215	217	219	221	224	226
SVTS 66 kV	502	497	507	513	521	528	538	547	558	569
TBTS 66 kV	286	293	301	305	312	317	325	332	340	348
TSTS 66 kV	319	328	334	344	348	352	357	361	367	371

Appendix B – Detailed NPV analysis

For detailed NPV analysis, including sensitivity and unweighted scenario results, refer to the Appendix B Excel file located on AEMO's website.

Important Notice

Purpose

AEMO publishes this Project Assessment Draft Report as required by clause 5.16.4(j) of the National Electricity Rules. This publication has been prepared by AEMO using information available at 1 March 2013, unless otherwise specified. Information made available after 1 March 2013 may have been included in this publication where practical.

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