Joint Regulatory Test Report

WESTERN METROPOLITAN MELBOURNE TRANSMISSION CONNECTION AND SUBTRANSMISSION CAPACITY

1 May 2012

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Executive Summary

Background and Purpose

This regulatory test report has been prepared by the Australian Energy Market Operator (AEMO), Jemena Electricity Networks (Jemena) and Powercor Australia (Powercor) in accordance with the requirements of clause 5.6.2 of the National Electricity Rules ("the Rules").

The purpose of this document is to provide a final report (pursuant to clause 5.6.2(h) of the Rules) on the preferred option to address emerging network constraints in the western Melbourne metropolitan area. This report has been prepared following the conclusion of consultation (in accordance with clause 5.6.2(f) of the Rules) on the credible options to address emerging network constraints in the western Melbourne metropolitan area.

This report:

- describes the need that AEMO, Jemena and Powercor ("the NSPs") are seeking to address, and the assumptions applied in identifying that need;
- describes and undertakes an economic assessment, in accordance with the regulatory test, of the credible options that the NSPs consider may address the identified need;
- presents the analysis methodology and summarises the economic assessment results;
- summarises the consultation process and issues arising; and
- identifies the recommended action to be taken, which is the establishment of Deer Park Terminal Station by November 2016, because that option maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market.

The need for investment

Keilor Terminal Station (KTS) is one of the major terminal stations in the Melbourne metropolitan area. It is located in the north west of greater Melbourne and it supplies a total of approximately 600 MW of demand to around 210,000 customers, in the inner western and north-western suburbs of Melbourne, as well as rural areas including Woodend, Sunbury, Lancefield and Kyneton.

In the 2011 Transmission Connection Planning Report (TCPR)[1], Jemena and Powercor identified that, due to significant demand growth from residential, industrial and commercial development to the west of Melbourne, action will be required to prevent loading distribution and transmission connection assets beyond their thermal capabilities. Along with the TCPR and further planning studies undertaken jointly by the NSPs, this report explains that there are significant economic benefits associated with increasing the transmission connection and subtransmission capacity – or reducing the loading on existing network assets – in the western Melbourne metropolitan area.

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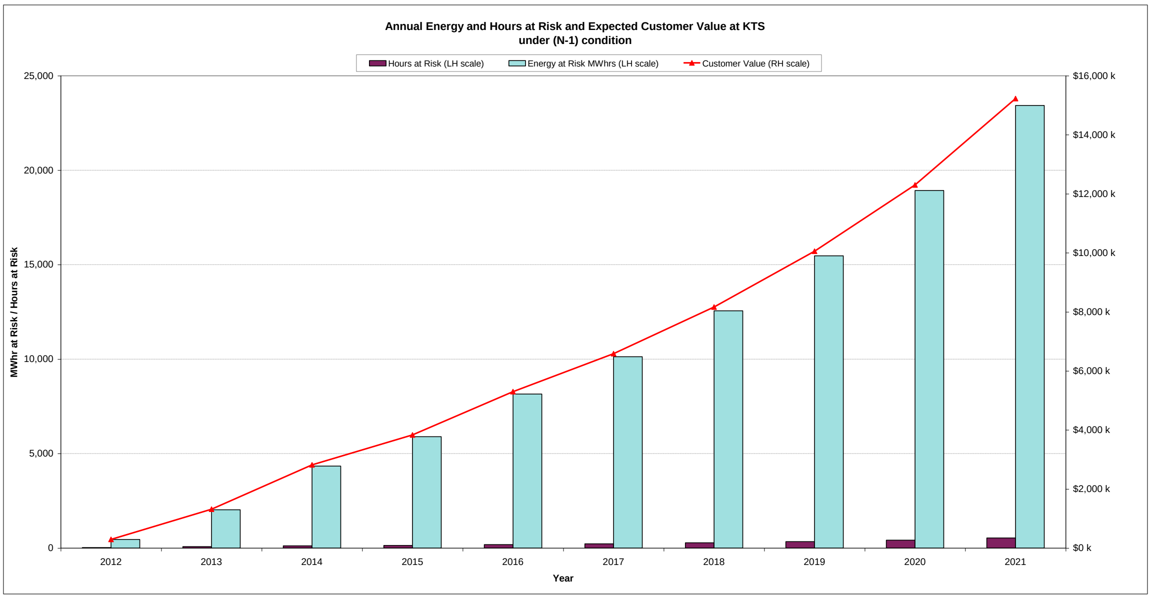
[1] CitiPower, Jemena Electricity Networks, Powercor Australia, SP AusNet and United Energy Distribution. "2011 Transmission Connection Planning Report". Available from: http://www.powercor.com.au/Electricity_Networks/Powercor_Network/Powercor_-_Network_Planning/.

Based on the latest available terminal station demand forecasts published by AEMO, the 2011 TCPR presented estimates of:

- the energy at risk[2] and expected unserved energy[3] at KTS with one transformer out of service for the 50th percentile demand forecast[4];
- the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating at the station; and
- the value to consumers of the expected unserved energy for the 50th percentile demand forecast.

The results of this analysis are shown in the figure below.

Figure 1: Energy at risk at KTS for the 50th percentile demand forecast



Based on the terminal station demand forecasts for KTS, the option assessments show that action to address the capacity constraint at the station, prior to the summer of 2016/17, is economically justified. In addition, action is economically justified over the next five years to address constraints within the sub-transmission network in the KTS supply area.

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[2] "Energy at risk" is, for a given forecast of demand, the total energy that would not be supplied if: a major outage of a transformer occurs at that station in a specified year; the outage has an expected duration of 2.6 months; and no other mitigating action is taken. This statistic provides an indication of the magnitude of loss of energy that would arise in the unlikely event of a major outage of a transformer. The term "major outage" is used throughout the TCPR to refer to an outage that has a mean duration of 2.6 months, typically due to a significant failure within the transformer. The actual duration of an individual major outage may vary from under 1 month up to 9 months. Further details are provided in section 4.4 of the 2011 TCPR.

[3] "Expected unserved energy" is the energy at risk weighted by the probability of a major outage of a transformer, where a "major outage" is defined as one that has a mean duration of 2.6 months. This statistic provides an indication of the amount of energy that may be expected to be not supplied in a year, taking into account the very low probability that one transformer at the station will be unavailable due to a major outage.

[4] A 50th percentile, or 50% probability of exceedence (POE), demand refers to a demand level that is expected to be exceeded once in every two year period. Similarly, a 10th percentile, or 10% POE, demand refers to a demand level that is expected to be exceeded once in every ten year period.

In light of the growing demand at KTS and the forecast increase in load at risk, the NSPs have examined a number of different options to increase capacity at the station and within the associated sub-transmission network. These options are outlined below.

Options for addressing projected constraints

Through joint planning, the NSPs have examined a number of long term options to augment the transmission connection and sub-transmission capacity in the KTS supply area. These options include various alternative configurations of sub-transmission loop augmentations along with different options for increasing transmission connection capacity at various existing and / or new sites. The six options identified for further detailed study and application of the regulatory test are:

- "Do nothing": This option provides a point of reference for determining the total net market benefit of each network option by presenting the expected involuntary load shedding that would be required to manage network loading assuming there was no network augmentation or non-network service provider action.

- Option 1: Establish a new Deer Park Terminal Station (for service by the end of 2016).

- Option 2: Install a sixth transformer at KTS and a fourth transformer at Altona Terminal Station (ATS) for service by the end of 2016.

- Option 3: Install a fourth transformer at ATS for service by the end of 2016.

- Option 4: Engage non-network support services; specifically demand management in the form of voluntary load curtailment to defer Option 1 by one year.

- Option 5: Establish and engage non-network support services; specifically in the form of local generation to defer sub-transmission line augmentation and the installation of a sixth transformer at KTS with all remaining augmentations as per Option 2.

Net market benefits of options

Table 1 shows the estimated net market benefits of these options relative to the "Do nothing" option over the period from 2012 to 2030, using central estimates for all variables.

Table 1: Summary of results – Base case cost-benefit analysis of options (Net market benefits relative to "Do nothing" option in present value terms in $ million)

	Total market benefit	Total cost	Net market benefit
Option 1	17,322	200	17,122
Option 2	17,311	230	17,081
Option 3	17,319	217	17,102
Option 4	17,309	194	17,115
Option 5	17,321	326	16,995

These results indicate the substantial net market benefits – in the form of large reductions in expected unserved energy - delivered by all augmentation options, relative to the "Do nothing" option. The results show that, assuming central estimates for all key variables, Option 1 delivers the highest net market benefits.

Table 2 below shows the results of the comparative analysis of the augmentation options, relative to Option 1. "Base case" denotes the use of central assumptions for all variables. The net market benefit of each option (relative to Option 1) under the base case scenario is shown in the first row of the table, and then results are presented reflecting the base case changed for one variable only (in turn: demand growth rate, capital cost, network operating costs, value of customer reliability and discount rate). The shaded cell in each row indicates the option that maximises net market benefit for that particular set of assumptions.

Table 2: Summary of results- Sensitivity testing of individual variables (Net market benefits relative to Option 1 in present value terms in $ million)

	Option 1	Option 2	Option 3	Option 4	Option 5
Base Case	**0**	**-41.3**	**-20.6**	**-7.5**	**-127.3**
Demand forecast sensitivity					
Lower bound (base annual growth rate reduced by 15%)	0	-29.6	-29.5	-0.5	-95.1
Capital cost sensitivity					
Upper Bound (Base + 30%)	0	-50.4	-25.8	-5.2	-116.9
Lower Bound (Base - 30%)	0	-32.2	-15.3	-9.8	-137.7
Operating cost sensitivity					
Upper Bound (Base + 50%)	0	-42.0	-21.0	-7.0	-125.4
Lower Bound (Base - 50%)	0	-40.7	-20.1	-7.9	-129.1
Value of customer reliability					
Upper Bound ($69,000 / MWh)	0	-42.3	-21.0	-9.2	-126.8
Lower Bound ($51,000 / MWh)	0	-40.3	-20.1	-5.7	-127.7
Discount rate sensitivity					
Upper Bound (12% real)	0	-25.9	-13.6	-3.4	-75.0
Lower Bound (6% real)	0	-52.0	-25.4	-10.1	-164.4

Examination of the sensitivity of net market benefits to changes in individual variables (shown in Table 2 above) is a precursor to full sensitivity testing involving different combinations of assumptions on all key variables. Table 2 shows that Option 1 is consistently the superior option when changes to individual variables are introduced.

Table 3 below sets out a comparison of the present value of net market benefits of each option for different combinations of assumptions applied under various scenarios. Seven scenarios are presented: the "base case" or most likely scenario, and six other scenarios, which represent plausible combinations of upper and lower bound assumptions on the key variables of demand growth, capital cost, operating cost, value of customer reliability and discount rate. The shaded cell in each row indicates the option that maximises net market benefit for that particular scenario.

Table 3: Summary of results - Economic evaluation of options under various scenarios (Net market benefits relative to Option 1 in present value terms in $ million)[5]

Scenario	Option 1	Option 2	Option 3	Option 4	Option 5
Base Case	**0**	**-41.3**	**-20.6**	**-7.5**	**-127.3**
Scenario A • Central demand growth • Upper bound capital cost • Upper bound operating cost • Central VCR estimate • Central discount rate	0	-51.3	-26.4	-4.6	-114.4
Scenario B • Central demand growth • Upper bound capital cost • Upper bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-63.6	-32.0	-5.6	-152.5
Scenario C • Central demand growth • Lower bound capital cost • Lower bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-38.5	-18.0	-10.4	-176.0
Scenario D • Lower bound demand growth • Upper bound capital cost • Upper bound operating cost • Central VCR estimate • Central discount rate	0	-36.6	-38.9	2.4	-78.8
Scenario E • Lower bound demand growth • Upper bound capital cost • Upper bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-48.2	-46.0	1.0	-114.2
Scenario F • Lower bound demand growth • Lower bound capital cost • Lower bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-28.9	-24.0	-3.9	-144.5

5 It should be noted that cost estimates for the non-network solutions, Options 4 and 5, are indicative-only. These estimates were adopted in the 10 February 2012 consultation paper, and they are shown in this report for completeness.

The results set out in Table 2 and Table 3 show that:

- Option 1 maximises net market benefit under the base case set of assumptions; and
- Option 1 maximises net market benefits in the majority of sensitivity tests and scenario analyses involving the variation of assumptions within plausible limits.
- Option 4 only provides maximum benefits if there is a combination of lower demand growth and higher capital cost. This indicates that if demand is 15% per annum less than forecast and capital costs are 30% higher, there may be scope for deferring the DPTS project one year.

The impact on net market benefits of deferring the proposed augmentation was examined. That examination confirms that under base case assumptions:

- Option 1 has the highest net market benefit of all options, regardless of whether the augmentation is delivered in 2016 or deferred for one year; and
- Commissioning Option 1 in 2016 will maximise net market benefits.

Examination of the impact on net market benefits of reduced demand forecasts – a reduction of 15% from the annual growth rate assumed in the base case – also confirmed that commissioning Option 1 in 2016 will maximise net market benefits.

A qualitative assessment of options against a number of considerations also suggests that Option 1 is the superior option. In particular:

- Option 1 requires the lowest amount of new line work construction in established residential and park land areas, thereby reducing community and environmental impacts; and
- Option 1 places transformation capacity closer to the load earlier than other options, and therefore delivers additional benefits in terms of reduced losses.

Results of consultation on options

On 10 February 2012, the NSPs published a consultation paper (in accordance with clause 5.6.2(f) of the Rules) on the possible options to address emerging network constraints in the western Melbourne metropolitan area. The consultation paper stated that the proposed project would involve constructing a new terminal station at Deer Park with two 150 MVA 220/66 kV transformers and six 66 kV exits on an existing site owned by SP AusNet, at the corner of Christies Road and Riding Boundary Road, Ravenhall by November 2016.

Interested parties were invited to lodge submissions by 26 March 2012.

No formal submissions were received, however some informal comments were made regarding the proposed sizing of transformer units. These comments have been addressed in this report, which concludes that Option 1 – the construction of a new Deer Park Terminal Station (DPTS) by November 2016 - remains the preferred option. However, the NSPs evaluated the net market benefits of installing 225 MVA transformers at DPTS instead of using 150 MVA units as proposed in the consultation paper. That evaluation indicates that installing 225 MVA transformers is likely to provide higher net market benefits than 150 MVA units. Accordingly, the NSPs now propose to take the recommended action which is outlined below.

Recommended action to be taken

The recommended action involves constructing a new terminal station at Deer Park (DPTS) with two 225 MVA 220/66 kV transformers and six 66 kV exits on an existing undeveloped site owned by SP AusNet, at the corner of Christies Road and Riding Boundary Road, Ravenhall by November 2016. If, during the course of progressing the detailed design of the project, it becomes evident that the 150 MVA alternative is more likely to maximise net market benefits, then the NSPs may revert to that network option.

The key elements of the proposed project also include:

- Connection of DPTS to the Keilor Terminal Station (KTS)-Geelong Terminal Station (GTS) No. 2 220 kV line.
- Connection to DPTS of a new zone substation Truganina (TNA) at 66/22 kV.
- Transferring 66/22 kV zone substations Melton (MLN) and Sunshine (SU) to DPTS, and the construction of a second KTS to Sunbury zone substation (SBY) 66 kV line to relieve overloads at KTS and on the existing KTS-SBY, KTS to Sydenham zone substation (SHM) and KTS-MLN 66 kV looped lines.

Next steps

In accordance with the provisions set out in clause 5.6.2(i) of the Rules, Registered Participants may, within 40 business days after the publication of this report, dispute the recommendation set out in this report. Accordingly, Registered Participants who wish to dispute the recommendation outlined in this report must do so by 27 June 2012. Any Registered Participants raising such a dispute are also asked to notify the officer identified below.

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1 Purpose

This regulatory test report has been prepared by the Australian Energy Market Operator (AEMO), Jemena Electricity Networks (Jemena) and Powercor Australia (Powercor) in accordance with the requirements of National Electricity Rules ("the Rules") clause 5.6.2.

In Victoria, the Distribution Businesses ("the DBs") are responsible for planning and directing augmentation of their distribution networks and the connection assets that connect their networks to the transmission network, known as the Declared Shared Network (DSN). AEMO is responsible for planning and directing augmentation of the Victorian DSN.

This report sets out the results of the technical and economic studies undertaken by AEMO, Jemena and Powercor ("the NSPs") to assess options to alleviate projected distribution and transmission connection asset constraints in the western Melbourne metropolitan area.

As part of the regulatory test process, and pursuant to clause 5.6.2(f) of the Rules, the NSPs published a consultation paper on 10 February 2012, to consult with registered participants and interested parties on the possible options to address emerging constraints in the western Melbourne metropolitan area. The consultation paper provided an economic assessment of options carried out in accordance with the regulatory test.

The regulatory test is a form of cost-benefit analysis for assessing alternative investment options. The current version of the test (version 3) comprises two limbs:

- the 'reliability limb', where investment is targeted to achieve mandated network performance requirements; and
- the 'market benefits limb', where investment is targeted to deliver the maximum net benefit to the market.

The investment options for the western Melbourne metropolitan area have been assessed in accordance with the market benefits limb of the regulatory test. Clause (1)(b) of the regulatory test states that an option satisfies this limb of the test if:[6]

> "the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the *market benefit* less *costs."*

This report:

- Describes the need that AEMO, Jemena and Powercor ("the NSPs") are seeking to address, and the assumptions applied in identifying that need.
- Describes and undertakes an economic assessment, in accordance with the regulatory test, of the credible options that the NSPs consider may address the identified need.
- Summarises the consultation process and issues arising.
- Identifies the establishment of Deer Park Terminal Station by November 2016 as the option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market.

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[6] Clause 1 of Version 3 of the regulatory test as published by the Australian Energy Regulator in its *Final Decision: Regulatory Test version 3* and in the accompanying *Application Guidelines*, in November 2007.

2 The need for investment

2.1 Background

Keilor Terminal Station (KTS) is one of the major terminal stations in the Melbourne metropolitan area. It is located in the north west of greater Melbourne and it supplies a total of approximately 600 MW of demand to around 210,000 customers, in the inner western and north-western suburbs of Melbourne, as well as rural centres including Woodend, Sunbury, Lancefield and Kyneton. The geographic area supplied from KTS is depicted in the map below.

Figure 2: Area supplied from Keilor Terminal Station

KTS comprises five 150 MVA transformers. Four of the transformers are split across two groups that are connected by three 66 kV line loops across an open 66 kV bus tie circuit breaker. The fifth transformer operates as a "hot standby"[7] unit and can connect to either

[7] A transformer that is connected as a "hot standby" unit generally has one side of the transformer disconnected from the network, such that it does not normally carry any load, to limit the maximum

bus group, as required, following loss of one of the other four transformers. By May 2012, the fifth transformer is planned to be permanently connected onto load by the creation of a fifth 66 kV bus at KTS and 66 kV loop rearrangements. Once these works are completed, the station will essentially be comprised of two separate transformer groups, as follows:

- A two transformer group comprised of the B3 and B4 transformers will supply the St Albans, Melton, Sydenham, Sunbury and Woodend areas.

- A three transformer group comprised of the B1, B2 and B5 transformers will supply the Melbourne Airport, Airport West, Pascoe Vale, Essendon, Braybrook and Sunshine areas.

Under these arrangements, the loss of a transformer on the B3 and B4 transformer group will be automatically replaced by one of the transformers on the other group. Automatic switching arrangements are not in place for the loss of one of the three transformers in the B1, B2 and B5 transformer group.

For the period prior to this project being completed, Jemena and Powercor will, under high load conditions, temporarily transfer load away and re-configure the station to enable the B5 transformer to take load under system normal conditions. The reconfiguration will increase the N rating of the station by opening 66 kV line loops across buses and temporarily supplying three zone substations on single radial lines. This reconfiguration is required to limit the maximum prospective fault levels, or short circuit current, on the existing four 66 kV buses to within switchgear ratings. The operational effect of the temporary station reconfiguration will be similar to the permanent splitting of the station into two groups, as described above.

In addition to the fifth transformer project described above, Powercor and Jemena[8] plan to direct the installation of a 100 MVAr capacitor bank at the station by the summer of 2013/14. The proposed capacitor bank will improve the power factor and reduce transformer load at the station. The analysis of emerging constraints at KTS, which is presented below, assumes that the proposed 100 MVAr capacitor bank is installed by the summer of 2013/14.

2.2 Emerging constraints at Keilor Terminal Station

Demand for electricity within the area supplied by KTS is undergoing significant growth due to the expansion of residential, industrial and commercial development to the west of Melbourne. In particular there are new large information technology loads in the form of several data centres proposed for the Sunshine area. The need to address emerging constraints at KTS has been identified in the 2011 TCPR and in previous TCPRs.

Based on the latest available terminal station demand forecasts published by AEMO, the 2011 TCPR presented estimates of:

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prospective fault level, or short circuit current contribution, that would result immediately following a network fault condition. Following loss of a parallel transformer, the hot standby transformer can be seamlessly connected to carry load. The result is that the station's N-1 rating will match its N rating.

[8] These DBs are responsible for planning and directing the augmentation of the transmission connection facilities at KTS.

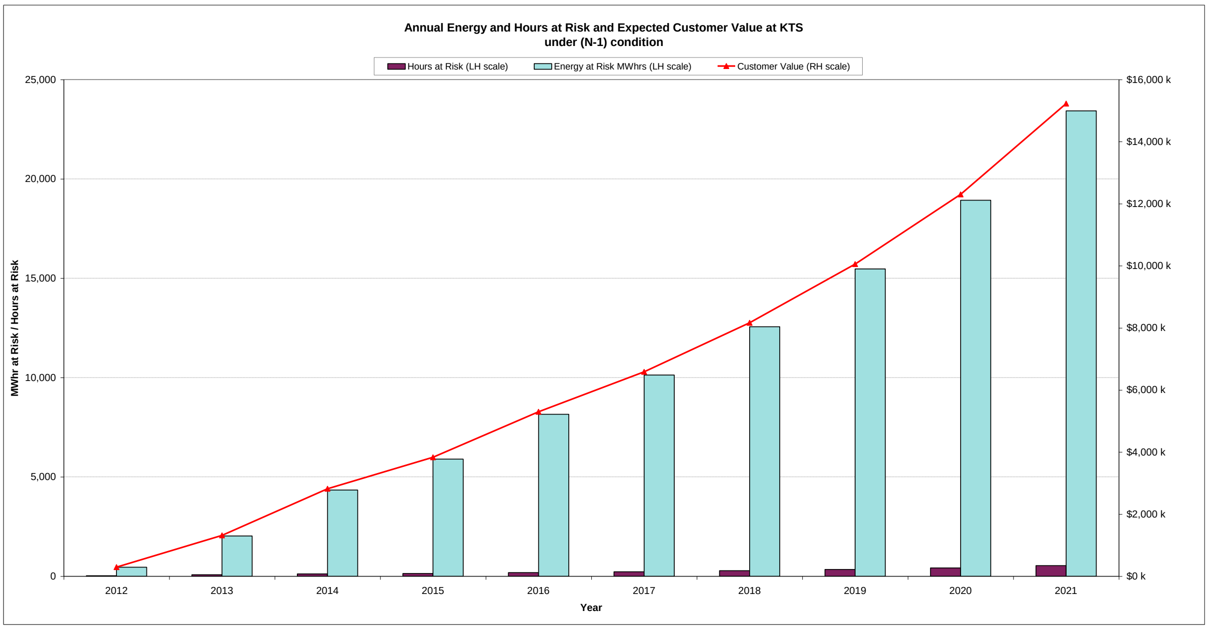
- the energy at risk[9] and expected unserved energy[10] at KTS with one transformer out of service for the 50th percentile demand forecast;

- the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating at the station; and

- the value to consumers of the expected unserved energy for the 50th percentile demand forecast.

The results of this analysis are shown in the figure below.

Figure 3: Energy at risk at KTS (assuming a 50th percentile demand)



The 2011 TCPR noted that once the permanent station reconfiguration is completed in May 2012, there will be sufficient capacity at the station to supply all customer demand until 2017 under system normal conditions (that is, all transformers in service) for the 50th percentile demand forecast. However from 2012 onwards, for a major outage of one transformer at KTS over the summer peak load period, there would be insufficient capacity at the station to supply all customer demand.

By summer 2016/17 (depicted as 2017 in Figure 3), the energy that would not be supplied under system normal (N condition) and a transformer outage (N-1 condition) on the KTS transformer groups is estimated to be 3.2 MWh and 10,128 MWh respectively for the 50th percentile demand forecast. Over the summer 2016/17 period, there would be insufficient capacity to meet demand for about 1 hour and 222 hours in that year under N and N-1

9 "Energy at risk" is, for a given forecast of demand, the total energy that would not be supplied if: a major outage of a transformer occurs at that station in a specified year; the outage has an expected duration of 2.6 months; and no other mitigating action is taken. This statistic provides an indication of the magnitude of loss of energy that would arise in the unlikely event of a major outage of a transformer.

10 "Expected unserved energy" is the energy at risk weighted by the probability of a major outage of a transformer, where a "major outage" is defined as one that has a mean duration of 2.6 months. This statistic provides an indication of the amount of energy that may be expected to be not supplied in a year, taking into account the very low probability that one transformer at the station will be unavailable due to a major outage.

conditions respectively. The estimated value to consumers of the 3.2 MWh and 10,128 MWh of the energy not supplied is approximately $192,000 and $607.7 million respectively (based on a value of customer reliability of $60,000 per MWh)[11].

In other words, at the 50th percentile summer demand level, and in the absence of any other operational response that might be taken to mitigate impacts on customers:

- under system normal conditions over the summer of 2016/17, insufficient capacity at KTS would be expected to lead to involuntary supply interruptions that would cost consumers $192,000; and

- a major outage of one transformer at KTS over the summer of 2016/17 would be anticipated to lead to further involuntary supply interruptions that would cost consumers $607.7 million.

It is emphasised however, that the probability of a major outage of one of the five transformers is very low, at about 1.0% per transformer per annum, whilst the expected unavailability per transformer per annum is 0.217%. When the energy at risk (10,128 MWh) is weighted by this low transformer unavailability, the expected unserved energy (for loss of one transformer) is estimated to be around 109.7 MWh. Combining this with the energy that would not be supplied (3.2 MWh) under system normal conditions, the total expected unserved energy is estimated to have a cost to consumers of around $6.8 million.

It should also be noted that the above estimates are based on an assumption of average (50th percentile) summer temperatures occurring in each year. If summer temperatures are higher, customer demand will increase significantly due to air conditioning loads. At the 10th percentile demand forecast, the energy that would not be supplied in the summer of 2016/17 for N and N-1 conditions is estimated to be 916.3 MWh and 15,335 MWh respectively. The estimated cost to consumers of this unserved energy in the summer of 2016/17 for N and N-1 conditions is approximately $55.0 million and $920.1 million respectively. The total corresponding value of the expected unserved energy is approximately $65 million.

These key statistics for the summer of 2016/17 under N and N-1 outage conditions are summarised in the table below.

The overall probability-weighted expected unserved energy considers the probability of a transformer outage combined with a 33% weighting on the 10th percentile demand and a 67% weighting on the 50th percentile demand, as described in section 4.2.

[11] The value of unserved energy is derived from the sector values given in Table 2-1 of the 2011 Victorian Annual Planning Report, weighted in accordance with the composition of the load, by sector, at KTS.

Table 4: Summary of analysis of energy at risk and expected unserved energy at KTS for summer 2016/17

	MWh	Valued at consumer interruption cost
Energy not supplied at 50th percentile demand forecast under N condition	3.2	$192,973
Energy at risk, at 50th percentile demand forecast under N-1 outage condition	10,128	$607.7 million
Expected unserved energy at 50th percentile demand under N-1 outage condition	109.7	$6.6 million
Total expected unserved energy at 50th percentile demand for N and N-1 conditions	112.9	$6.8 million
Energy not supplied at 10th percentile demand forecast under N condition	916.3	$55.0 million
Energy at risk, at 10th percentile demand forecast under N-1 outage condition	15,335	$920.1 million
Expected unserved energy at 10th percentile demand under N-1 outage condition	166.1	$10.0 million
Total expected unserved energy at 10th percentile demand for N and N-1 conditions	1,082.4	$65.0 million
Overall probability-weighted expected unserved energy	**432.8**	**$26.0 million**

2.3 Emerging distribution system constraints

The Jemena 2011 Distribution System Planning Report (DSPR) identified that there are emerging constraints over the five-year (2012-2016) distribution planning period for the KTS-SHM, KTS-SBY and KTS-MLN 66 kV sub-transmission lines forming the KTS-MLN-SBY(WND)-SHM-KTS loop system. The KTS-MLN-SBY(WND)-SHM-KTS 66 kV sub-transmission loop supplies zone substations Melton (MLN), Woodend (WND), Sunbury (SBY) and Sydenham (SHM) from Keilor Terminal Station (KTS). The DSPR outlined that[12]:

- the most critical line on the KTS-MLN-SBY(WND)-SHM-KTS 66 kV sub-transmission loop is the KTS-SBY 66 kV line under the first order contingency condition of loss of the KTS-SHM 66 kV line. The KTS-SBY 66 kV line is made up of a combination of steel, aluminium with steel reinforcement, all aluminium and copper conductors. Therefore it is tentatively planned to reconductor this line with the standard 37/3.75 AAC towards the end of the five year (2012-2016) distribution planning period; and

- Jemena and Powercor, in conjunction with AEMO are currently investigating the future plan for supplying the Western Melbourne Region. The preferred option under review involves the transfer of zone substation MLN to the new Deer Park Terminal Station which would remove the contingent risk load from the KTS-SBY(WND)-SHM-KTS loop.

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12 Jemena Electricity Networks,*2011 Distribution System Planning Report*. The report is available at: http://jemena.com.au/Assets/What-We-Do/Assets/Jemena-Electricity-Network/Planning/Distribution%20System%20Planning%20Report%202011.pdf

Recent joint planning studies (which extend to 2030) completed by Jemena, Powercor and AEMO have confirmed the need to address emerging constraints on the KTS-MLN-SBY(WND)-SHM-KTS 66 kV sub-transmission loop.

The results of recent studies for the 50th percentile demand forecast are outlined below.

Figure 4 depicts the energy not supplied under system normal condition for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N capability rating. The line graph shows the value to consumers of the energy that would not be supplied in each year, for the 50th percentile demand forecast.

Figure 4: Energy not supplied at KTS-MLN-SBY(WND)-SHM-KTS 66kV sub-transmission loop under N condition (assuming a 50th percentile demand)

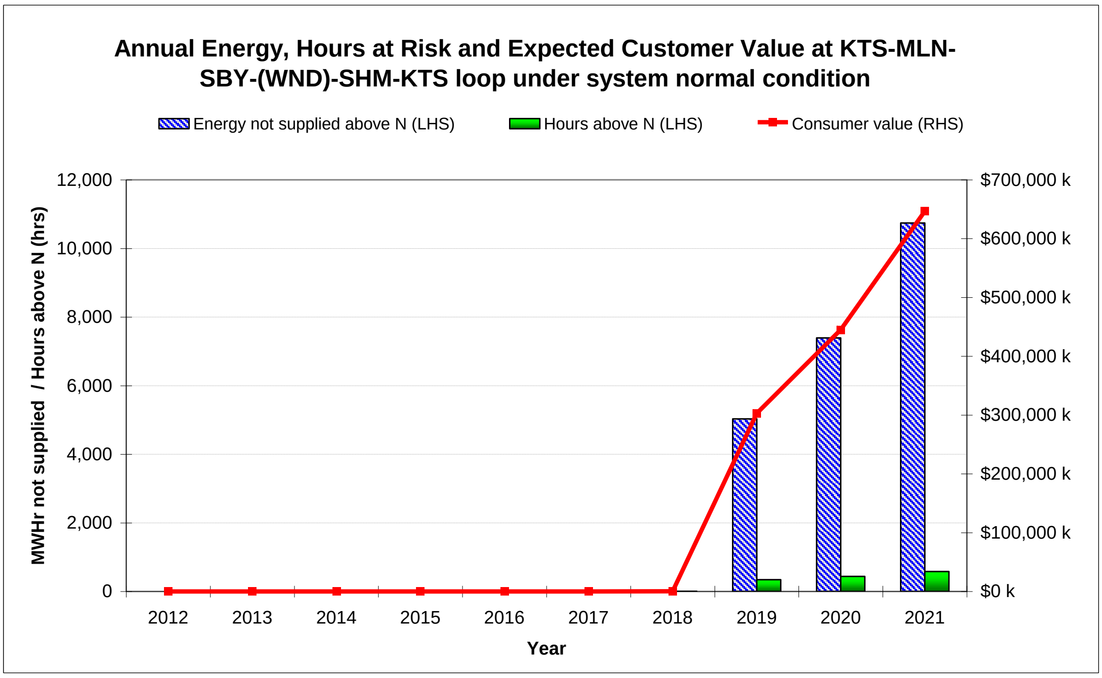
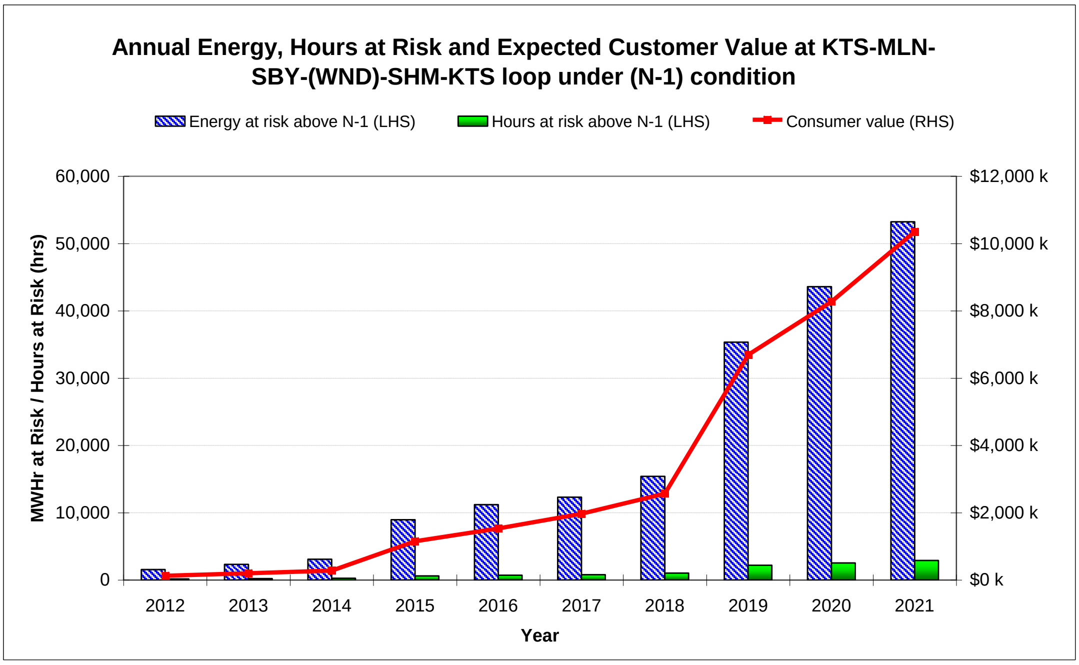


Figure 5 depicts the energy at risk with one line out of service (N-1 condition) for the 50th percentile demand forecast, and the hours per year that the 50th percentile demand forecast is expected to exceed the N-1 capability rating. The line graph shows the value to consumers of the expected unserved energy in each year, for the 50th percentile demand forecast.

Figure 5: Energy at risk at KTS-MLN-SBY(WND)-SHM-KTS 66kV sub-transmission loop under N-1 condition (assuming a 50th percentile demand)



As shown in Figure 4, there will be sufficient capacity on the loop to supply all customer demand until 2018 under system normal condition for the 50th percentile demand forecast. However, Figure 5 shows that from 2012 onwards, for a line outage over the summer peak load period, there would be insufficient capacity on the remaining lines to supply all customer demand.

By summer 2016/17 (depicted as 2017 in Figure 5), the energy at risk under a line outage (N-1 condition) is estimated to be 12,316 MWh for the 50th percentile demand forecast. Over the summer 2016/17 period, there would be insufficient capacity to meet demand for about 798 hours in that year for an N-1 condition. The estimated value to consumers of the 12,316 MWh of the energy at risk is approximately $739 million (based on a value of consumer reliability of $60,000/MWh).

It is emphasised however that the probability of a line outage is low, at about 0.093 faults per km of line per annum, whilst the expected unavailability per line per annum is 0.2128%. When the energy at risk is weighted by this low line unavailability, the expected unserved energy (for the entire loop) is estimated to be around 32.7 MWh. The total expected unserved energy is estimated to have a value to consumers of around $2 million.

These key statistics for the summer of 2016/17 under N-1 outage condition are summarised in the table below.

Table 5: Summary of analysis of energy risk and expected unserved energy at KTS-MLN-SBY(WND)-SHM-KTS 66kV sub-transmission loop for summer 2016/17

	MWh	Valued at consumer interruption cost
Energy at risk, at 50th percentile demand forecast under N-1 outage condition	12,316	$739 million
Expected unserved energy at 50th percentile demand under N-1 outage condition	32.7	$1.97 million

2.4 Closing comments on the need for investment

Terminal station demand forecasts for KTS indicate that by the summer of 2016/17, there will be a risk of substantial involuntary supply interruption due to inadequate capacity at the station. In addition, action is economically justified over the next five years to address constraints within the sub-transmission network in the KTS supply area.

In light of the growing demand at KTS and the forecast increase in load at risk, the NSPs have examined a number of different options to increase capacity, or reduce loading, at Keilor and within the associated sub-transmission network. These options are outlined in section 3.

3 Investment Options

3.1 Regulatory test requirements

The market benefits limb of the regulatory test requires the assessment of a proposed investment option relative to a number of alternative options, where the term "alternative option" is defined as:[13]

(a) a genuine alternative to the option being assessed, in that it:

  (i) delivers similar outcomes to those delivered by the option being assessed; and

  (ii) would become operational in a similar timeframe to the option being assessed;

(b) a practicable alternative to the option being assessed in that it is technically feasible.

In determining whether an alternative option is likely, a network service provider must consider a range of matters, including whether the alternative option has a genuine proponent and whether it is commercially feasible.[14] However, the absence of a proponent will not in itself exclude a project from being a likely alternative option for the purpose of the regulatory test.[15]

Clause 11 of the regulatory test requires the NSPs to consider whether any option provides other services in addition to prescribed network services. In cases where other services are also provided, the regulatory test requires a particular treatment of the 'other service' component of the investment. It should be noted, however, that all of the options (described below) to address the emerging constraints in the western Melbourne metropolitan area only provide prescribed transmission and distribution services.

3.2 Alternative options considered, and study horizon adopted

A number of long-term options to augment transmission connection and sub-transmission capacity in the western Melbourne metropolitan area have been identified and assessed to varying levels. These options include various alternative configurations of sub-transmission loop augmentations along with different options for increasing or offloading transmission connection capacity at various existing and/or new sites. The options examined included the following:

- establishing a new terminal station at Deer Park;
- installing a sixth transformer at KTS and a fourth transformer at Altona Terminal Station (ATS) with load then being transferred away to ATS and Brooklyn Terminal Station (BLTS);
- installing a fourth transformer at ATS with load then being transferred away to ATS and BLTS;

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[13] Clause 16 of the Regulatory Test.

[14] Clause (17)(b) and (17)(c) of the Regulatory Test. The extent to which an alternative option is commercially feasible is to be demonstrated by determining whether an objective operator, acting rationally according to the economic criteria prescribed by this test, would be prepared to construct or provide the alternative option.

[15] Clause (17)(b) of the Regulatory Test.

- installation of connection asset transformation capacity at the existing Sydenham Terminal Station site;

- construction of a new terminal station at Tarneit;

- construction of a new terminal station at Truganina;

- installation of a third transformer at BLTS;

- engagement of non-network support services; specifically demand management in the form of voluntary load curtailment to defer the establishment of new Deer Park Terminal Station; and

- establishment and engagement of non-network support services; specifically in the form of local generation on the sub-transmission KTS-SBY-MLN loops to defer the installation of a 6^{th} transformer at KTS whilst retaining a new 4th transformer at ATS with load transferred away from KTS to BLTS as per the second dot point above.

Following initial assessment, some of these options (described below) were not studied in further detail, because their costs were assessed as being considerably higher than other options:

- Development of a new station at Sydenham was excluded from further detailed examination because Sydenham is not located in the proximity of the metropolitan growth area. This option would therefore require additional 66 kV line work compared to other options, and it would involve the installation of expensive 500/220 kV transformation before connection assets could be installed.

- Development of a new station at Tarneit was not examined in further detail because it would be located further away from the northern growth corridor than other options, and it would therefore require the installation of considerably more 66 kV lines to supply zone substations Melton (MLN) and Sunshine (SU).

- Development of a new Truganina Terminal Station was not examined further as it would require expensive 500/220 kV transformation or costly 220 kV line diversion work from the existing Keilor to Geelong line easement. This option would cost considerably more than the options included in this regulatory test assessment.

- Augmentation of Brooklyn Terminal Station (BLTS) was not examined in further detail because the installation of a third transformer after completion of the station rebuild in 2012 would require the existing 66 kV loops to ATS to return to BLTS at a cost of $32 million, in addition to the costs of Option 3 (described in Table 6 below).

Table 6 details the alternative network options that the NSPs consider to be credible options for addressing the emerging constraints.

For the purpose of evaluating the costs and net market benefits of each option, a study horizon of 19 years (to 2030) was adopted. It is noted that from 2030 onwards:

- future investment requirements are expected to be unaffected by the choice of alternative options today; and

- all the alternative options (apart from “Do nothing”) are expected to deliver comparable levels of network service and reliability.

Therefore, the costs and benefits delivered under all the alternative options from 2030 can be considered to be comparable. In view of the uncertainty associated with projecting network performance and investment requirements beyond 2030, and the effect of applying a discount rate to cash flows occurring at that time, all costs and benefits accruing beyond 2030 have been excluded from the analysis of net market benefits.

Each of the alternative options assessed under this application of the Regulatory Test include investments from 2016 to 2030. This is necessary in order to identify the investments in the short-term which will be the most efficient over the long-term. However this Regulatory Test application is being used to justify the initial investments only. The NSPs will continue to work together to identify the optimal timing of the subsequent investments at the appropriate time using the latest available information.

Table 6: Network only options for addressing emerging constraints in the KTS supply area

Option	Description	**Indicative capital cost** in present value terms at 8% real discount rate
"Do nothing"	This option provides a point of reference for determining the total net market benefit of each network option.	Zero
Option 1: Establish Deer Park Terminal Station	This option involves the establishment of new terminal station at Deer Park (DPTS) by November 2016 including: • two 150 MVA 220/66 kV transformers and six 66 kV exits at DPTS • connection to KTS-Geelong Terminal Station (GTS) No.2 220 kV line • construction of 66 kV lines to connect new zone substation Truganina (TNA) to DPTS • construction of 66 kV lines to transfer existing zone substations Melton (MLN) and Sunshine (SU) to DPTS • construction of a second KTS-Sunbury zone substation (SBY) 66 kV line to relieve overloads at KTS and on the KTS-SBY-SHM-MLN 66 kV loops Installation of third transformer at DPTS by November 2018 including: • 150 MVA 220/66 kV transformer at DPTS • construction of 66 kV lines to connect new Rockbank East zone substation (RBE) to DPTS Installation of fourth transformer at ATS by November 2021 including: • 150 MVA 220/66 kV transformer at ATS • construction of 66 kV lines to connect new Tarneit zone substation (TRT) to ATS • construction of 66 kV lines to transfer existing Bacchus Marsh zone substation (BMH) to ATS • construction of a second KTS-Sydenham (SHM) 66kV line (KTS-SHM No.2) Connection of second 220 kV line (KTS-GTS No.1) at DPTS by November 2023. Installation of fourth transformer at DPTS by November 2024 including: • 150 MVA 220/66 kV transformer at DPTS • construction of 66 kV lines to transfer existing Sunshine East zone substation (SSE) to DPTS Installation of a sixth transformer at KTS by November 2025 including: • 150 MVA 220/66 kV transformer at KTS • augmentation of KTS-SBY 66 kV line Construction of 66kV lines to connect new Rockbank zone substation (RBK) to DPTS by November 2026 Construction of 66kV lines to connect new Wyndham Vale zone substation (WVL) to ATS by November 2027 Two 100 MVAr capacitor banks at DPTS by November 2029.	$187.4 million

<table>
<tr><th>Option</th><th>Description</th><th>Indicative capital cost
in present value terms at 8% real discount rate</th></tr>
<tr><td>Option 2:
Install KTS 6th and ATS 4th transformers</td><td>This option involves installing a sixth transformer on the KTS B3,4 group, and transferring SU zone substation to BLTS to reduce load on the KTS B1,2,5 group by November 2016 involving:
• installing a sixth 150 MVA 220/66 kV transformer at KTS
• construction of 66 kV lines to transfer existing SU zone substation to BLTS
• installing a fourth 150 MVA 220/66 kV transformer at ATS
• construction of 66kV lines to connect new TNA zone substation to ATS
• construction of 66kV lines to transfer existing BMH and MLN zone substations to ATS
• construction of a second KTS-Sunbury zone substation (SBY) 66 kV line to relieve overloads at KTS and on the KTS-SBY-SHM-MLN 66 kV loops
Construction of 66kV lines to connect new RBE to KTS by November 2018
Construction of a second KTS-SHM 66 kV line (KTS-SHM No.2) by November 2020
Construction of 66kV lines to connect new TRT to ATS by November 2021
Establishment of new terminal station at Deer Park (DPTS) by November 2023 including:
• four 150 MVA 220/66 kV transformers and eight 66 kV exits at DPTS
• connection to KTS-GTS No2 220 kV line
• construction of 66kV lines to transfer existing zone substations MLN, RBE, SSE, SU, TNA to DPTS
• connection of second 220 kV line (KTS-GTS No.1) to DPTS
• construction of 66 kV lines to split ATS-TRT-BMH loops
Augmentation of KTS-SBY 66 kV line by November 2025
Construction of 66 kV lines to connect new zone substation RBK to DPTS by November 2026
Construction of 66 kV lines to connect new zone substation WVL to ATS and split ATS-TRT-WBE loop by November 2027
Two 100 MVAr capacitor banks at DPTS by November 2029.
The alternative to transferring SU to BLTS is to install a seventh transformer at KTS on the B1, 2, 5 group. This is a similar cost to transferring load but is not preferred as it concentrates too much load at KTS and exposes customers to unacceptable reliability and security risks.
It is noted that this option involves additional 66 kV lines from KTS to RBE & SHM before DPTS is required. This requires new 66 kV line exits at KTS in a westerly direction that are difficult to obtain due environmental constraints and restricted access corridors hence additional 66 kV underground cable is required.</td><td>$216.6 million</td></tr>
</table>

Option	Description	**Indicative capital cost** in present value terms at 8% real discount rate
Option 3: Install ATS 4th Transformer	This option involves the installation of a fourth transformer at ATS to supply TNA and MLN by November 2016 and involves the following: • construction of 66 kV lines to transfer existing SU zone substation to BLTS • installing a fourth 150 MVA 220/66 kV transformer at ATS • construction of 66 kV lines to connect new TNA zone substation to ATS • construction of 66 kV lines to transfer existing BMH and MLN zone substations to ATS • construction of a second KTS-Sunbury zone substation (SBY) 66 kV line to relieve overloads at KTS and on the KTS-SBY-SHM-MLN 66 kV loops Establishment of new terminal station at Deer Park (DPTS) by November 2018 including: • two 150 MVA 220/66 kV transformers and four 66 kV exits at DPTS • connection to KTS-GTS No2 220 kV line • construction of 66 kV lines to connect new zone substation RBE to DPTS • construction of 66 kV lines to transfer existing zone substation MLN to DPTS Construction of a second KTS-SHM 66 kV line (KTS-SHM No.2) by November 2021 Construction of 66 kV lines to connect new zone substation TRT to ATS by November 2021 Installation of third transformer at DPTS by November 2024 including: • 150 MVA 220/66 kV transformer at DPTS • construction of 66 kV lines to transfer existing zone substations SU and TNA to DPTS • connection of second 220 kV line (KTS-GTS No1) at DPTS Installation of fourth transformer at DPTS by November 2025 including: • 150 MVA 220/66 kV transformer at DPTS • construction of 66 kV lines to transfer existing zone substation SSE to DPTS Installation of a sixth transformer at KTS by November 2025 including: • 150 MVA 220/66 kV transformer at KTS • augmentation of KTS-SBY 66 kV line Construction of 66 kV lines to connect new zone substation RBK to DPTS by November 2026 Construction of 66 kV lines to connect new zone substation WVL to ATS by November 2027 Two 100 MVAr capacitor banks at DPTS by November 2029.	$204.0 million

3.3 Investment sequence and capital costs of network only options

Capital cost forecasts are based on planning estimates provided by SP AusNet, and parameters developed by AEMO, Jemena and Powercor, based on internal knowledge and costs from recent network augmentations. Table 7 below shows the timing and estimated cost of work under each option, based on the central demand forecasts. Note that only the works shown in 2016 are those being justified in this Regulatory Test application.

Table 7: Investment timing and capital costs of network options under central demand forecasts

Network Options						
Year Built	**Option 1**	**Cost, $ million**	**Option 2**	**Cost, $ million**	**Option 3**	**Cost, $ million**
2012						
2013	KTS B3,4 group 1x100MVAr capacitor bank		KTS B3,4 group 1x100MVAr capacitor bank		KTS B3,4 group 1x100MVAr capacitor bank	
2014						
2015						
2016	DPTS with 2 x transformers, 220kV KTS-GTS No2, MLN, SU & TNA; KTS-SBY No2	125	KTS 6th transformer, ATS 4th transformer; KTS-SBY No2; SU to BLTS; MLN, TNA & BMH to ATS/West	96.5	ATS 4th transformer; BMH, MLN & TNA to ATS/West, KTS-SBY No2, SU to BLTS	97.6
2017						
2018	DPTS 3rd transformer & RBE	19.9	RBE to KTS West	37.4	DPTS with 2 x transformers, 220kV KTS-GTS No2, MLN & RBE	77.8
2019						
2020			KTS-SHM2	39.2		
2021	ATS 4th transformer; TRT & BMH to ATS/West; KTS-SHM No2	64.5	TRT to ATS/West	16.5	TRT to ATS/West; KTS-SHM No2	46.1
2022						
2023	DPTS 220kV KTS-GTS No1 switching	11.2	DPTS with 4 x transformers, 220kV KTS-GTS No2, MLN, RBE, TNA, SU & SSE. DPTS 220kV KTS-GTS No1 switching; ATS-TRT-BMH loop split	150.5		
2024	DPTS 4th transformer; SSE to DPTS	33.6			DPTS 3rd transformer with TNA & SU; DPTS 220kV KTS-GTS No1 switching	49.2
2025	KTS 6th transformer; KTS-SBY augmentation	22.8	KTS-SBY augmentation	5	KTS 6th transformer; KTS-SBY augmentation; DPTS 4th Tx; SSE to DPTS	43.8
2026	RBK to DPTS	14.4	RBK to DPTS	16.4	RBK to DPTS	15.4
2027	WVL to ATS	51.1	WVL to ATS; TRT & WBE Loop Split	55.4	WVL to ATS	51.1
2028						
2029	DPTS 2x100MVAr capacitor banks	11.8	DPTS 2x100MVAr capacitor banks	11.8	DPTS 2x100MVAr capacitor banks	11.8
2030						
Total Cost		354.3		428.7		392.8
NPV (8% discount rate)		**187.4**		**216.6**		**204.0**

It is noted that whilst all network only options require the installation of a sixth transformer at KTS, Options 1 and 3 do not require construction of new lines. The cost of Option 2 is comparatively high because the KTS sixth transformer is required much earlier (2016) compared with the estimated timing of 2025 under Options 1 and 3. In addition, Option 2 involves the construction of new lines out of KTS.

It is also noted that whilst a sixth transformer has been identified as a long term requirement at KTS, the cost of this additional capacity could be reduced or eliminated completely if SP AusNet's future asset replacement program increases the capacity of the existing B3 & B4 transformers to 225 MVA. In terms of the investment analysis presented here, Option 2 is less able to benefit from such a decision because of its earlier planned introduction of the sixth transformer.

The costs associated with common zone substation works and the proposed 2013 KTS B3 and B4 transformer group 100 MVAr capacitor bank have been excluded from the analysis.

3.4 Non-network alternative options

The NSPs have identified two potential non-network options that could be used in combination with the network alternatives that may create market benefits similar to those of the network only options identified. The two potential non-network options identified are demand management in the form of voluntary load reduction and development of local generation:

- Option 4: Utilise demand management at KTS to defer DPTS.
- Option 5: Utilise generation on the sub-transmission KTS-SBY-MLN loops at KTS West (B3 & B4 group) to defer the installation of the 6th transformer and 66kV line augmentation with all other investment streams maintained as per Option 2.

This section describes the technical characteristics required of a non-network support option to meet the identified need to invest. It also includes estimated costs to implement and contract for non-network support services, assuming that such an option is technically feasible within a similar timeframe as the recommended network augmentation.

The primary market benefits associated with the identified need to invest relate to reducing the expected amount of involuntary load shedding that would be required to maintain transmission connection asset and distribution network loading within plant limitations if alternative action was not taken. To achieve similar levels of market benefits, it is expected that a non-network option would also need to be able to reduce the amount of involuntary load shedding required to maintain transmission connection asset and distribution network loading within plant limitations.

To provide an economic comparison with the network options identified, the NSPs have prepared cost estimates of implementing and contracting for non-network support services. The estimates are based on the NSPs' knowledge, derived from previous non-network support arrangements, and discussions with non-network service providers.

Non-network support costs have been separated into three components, including:

- Service availability charge, which is generally in the form of a regular payment to the non-network service provider for having the support services in place, even if those services are not utilised.
- Support charge, which is generally in the form of a payment to the service provider when their services are called upon. For a local generator this cost would include

their short run marginal cost as compensation for the fuel used to operate their generator. For a demand management option in the form of voluntary load reduction this support cost would include a compensation payment to the service provider for reducing their demand when requested.

- Organisational cost, which is the consultancy services to investigate the potential for demand management, to prepare plans, arrange support contracts and coordinate network support when required.

Non-network support cost estimates were prepared for the two alternative options identified, demand management in the form of voluntary load reduction and local generation development in conjunction with capital investment streams for Option 1 and Option 2 respectively. The estimated non-network support unit costs are presented in Table 8.

Table 8: Capital and operational cost estimates of non-network support services

Non-network option	Service availability charge	Support Charge	Organisational Cost
Demand management by voluntary load reduction	$4,800/MW/ Month	$1,300/MW/hr	$80,000/MW
Local generation development	$0.1M/MW	$300/MWh	N/A

Table 9 and Table 10 present the expected load reduction, or additional generation, required by location and the number of hours in each year that would likely be required at Keilor Terminal Station.

Because the network limitations are based on continuous, short-term and cyclic asset ratings under system normal and outage conditions, a non-network option would be required to operate within the fifteen minute response time required operationally.

Table 9: KTS East (B1,2,5 group) total load at risk or above system normal

Year	50th percentile Load above System Normal 'N' Rating (MVA)	Time 50th percentile Load above System Normal 'N' Rating (hours)	50th percentile Load above System 'N-1' Cyclic Rating (MVA)	Time 50th percentile Load above System 'N-1' Cyclic Rating (hours)	10th percentile Load above System Normal 'N' Rating (MVA)	Time 10th percentile Load above System Normal 'N' Rating (hours)	10th percentile Load above System 'N-1' Cyclic Rating (MVA)	Time 10th percentile Load above System 'N-1' Cyclic Rating (hours)
2012	0	0	55	27	0	0	92	47
2013	0	0	92	74	0	0	132	96
2014	0	0	122	118	0	1	163	170
2015	0	0	138	137	17	5	163	212
2016	0	0	156	182	36	16	163	255
2017	0	0	169	222	50	19	163	302
2018	12	1	170	279	64	22	163	341
2019	25	3	170	335	78	25	163	415
2020	39	9	170	409	93	28	163	502
2021	54	11	170	523	108	30	163	628
2022	68	14	170	645	124	41	163	788
2023	83	29	170	791	140	48	163	958
2024	99	36	170	976	156	58	163	1088
2025	115	54	170	1124	173	68	163	1220
2026	131	66	170	1262	190	86	163	1317
2027	147	80	170	1381	208	106	163	1412
2028	164	101	170	1479	226	147	163	1462
2029	182	116	170	1578	244	170	163	1539
2030	200	130	170	1673	263	203	163	1600

Table 10: KTS West (B3,4 group) total load at risk or above system normal

Year	50th percentile Load above System Normal 'N' Rating (MVA)	Time 50th percentile Load above System Normal 'N' Rating (hours)	10th percentile Load above System Normal 'N' Rating (MVA)	Time 10th percentile Load above System Normal 'N' Rating (hours)
2012	0	0	6	4
2013	0	0	1	1
2014	0	0	0	0
2015	0	0	8	4
2016	0	0	23	13
2017	5	1	39	25
2018	21	5	56	31
2019	37	16	73	35
2020	55	29	92	39
2021	73	52	112	54
2022	93	73	133	66
2023	113	101	155	81
2024	135	131	178	97
2025	157	170	202	125
2026	181	210	228	161
2027	206	251	254	200
2028	232	316	282	247
2029	260	387	312	311
2030	289	507	343	403

Option 4: Demand management at KTS to defer DPTS.

This option is the same as Option 1 except that DPTS is deferred one year to 2017 by using demand management to alleviate unserved energy. The actual amount of demand management support available can vary depending on the type of customer connected and their ability and readiness to curtail load as requested. Previous experience on a very small scale of 22 MW total load in a Victorian country location, has provided up to 3.6% of total demand towards load reduction. On a larger scale, a recent consultation report for a major Melbourne terminal station with 500 MVA of load revealed approximately 6% of potential demand management with only 10 MVA (2%) that could be relied on. A recent desktop study for another major Melbourne terminal station has revealed 3% potential demand management.

A preliminary desktop study for the Powercor component of KTS (approximately 50% of the total load) has revealed approximately 2% of potential demand management from the top 20 customers. It is assumed that this could be replicated in the Jemena area. For the purpose of this study, 2% or 17 MVA by 2016/17 of demand management has been assumed to alleviate 50% PoE load above system normal 'N' as a first priority, with any remaining demand management capability being used to reduce any 10% PoE load above 'N'.

Option 5: Utilise generation on the sub-transmission KTS-SBY-MLN loops at KTS West (B3 & B4 group) to defer the installation of the 6th transformer and KTS-SBY and KTS-SHM 66kV line augmentation with remaining investment streams maintained as per Option 2.

This option is similar to Option 2, except that the 6th transformer is deferred beyond the study period in lieu of generation to supply load above system normal 'N' at KTS West (B3,4 group). It is assumed that distributed generation is installed on the sub-transmission network and load above 'N' and/or 'N-1' on KTS-SBY-MLN 66 kV loop lines can also be alleviated. Therefore augmentation of existing 66 kV lines to alleviate the load at risk and load above 'N' as required in Option 2 is deferred to 2023. DPTS is also deferred to 2023 as per Option 2.

There would be no generation required on the KTS B1, B2 & B5 bus group as SU zone substation is transferred to BLTS when the ATS 4th transformer is installed in November 2016 as per the Option 2 investment stream.

Table 10 above shows the indicative unserved load at KTS West (B3,4 group). In addition to load above 'N' at KTS West, there is emerging load at risk on the KTS-SBY line for the loss of KTS-SHM, which grows to be in the order of 140 MVA for 3,170 hours by 2023 before DPTS and associated 66 kV lines are built.

There is also significant growing load at risk on the KTS-MLN and KTS-SHM 66 kV lines as well. Without augmentation and with the inclusion of a new zone substation at Rockbank East by 2018 on the KTS-MLN line, there is also load above system normal 'N' on most of the above lines. In particular the KTS-MLN line could have in the order of 55 MVA of load for 340 hours above 'N' by summer of 2019 growing to 120 MVA for 2,470 hours by 2023 before DPTS and associated 66 kV lines are built.

The table below shows the network investment timing and capital costs of non-network options under central demand forecasts.

Table 11: Network investment timing and capital costs of non-network options under central demand forecasts

Non-Network Options								
Year Built	**Option 4**	**Cost, $ million**	**Demand Management, $ million**	**Total, $ million**	**Option 5**	**Cost, $ million**	**Generator Payments, $ million**	**Total, $ million**
2012								
2013	KTS B3,4 group 1x100MVAr capacitor bank				KTS B3,4 group 1x100MVAr capacitor bank			
2014								
2015								
2016					ATS 4th transformer; SU to BLTS; MLN, TNA & BMH to ATS/West	47.4		47.4
2017	DPTS with 2 x transformers, 220kV KTS-GTS No2, MLN, SU & TNA; KTS-SBY No2	125	3.4	128.4			4.1	4.1
2018	DPTS 3rd transformer & RBE	19.9		19.9	RBE to KTS-MLN	1.3	6.0	7.3
2019							21.2	21.2
2020							28.6	28.6
2021	ATS 4th transformer; TRT & BMH to ATS/West; KTS-SHM No2	64.5		64.5	TRT to ATS/West	16.5	39.6	56.1
2022							53.7	53.7
2023	DPTS 220kV KTS-GTS No1 switching	11.2		11.2	DPTS with 4 x transformer, 220kV KTS-GTS No2, MLN, RBE, TNA, SU & SSE. DPTS 220kV KTS-GTS No1 switching; ATS-TRT-BMH loop split; KTS-SBY No2; KTS-SHM No2	197	159.0	356.0
2024	DPTS 4th transformer; SSE to DPTS	33.6		33.6			1.1	1.1
2025	KTS 6th transformer; KTS-SBY augmentation	22.8		22.8	KTS-SBY augmentation	5	2.7	7.7
2026	RBK to DPTS	14.4		14.4	RBK to DPTS	16.4	4.4	20.8
2027	WVL to ATS	51.1		51.1	WVL to ATS; TRT & WBE Loop Split	55.4	6.3	61.7
2028							8.2	8.2
2029	DPTS 2x100MVAr capacitor banks	11.8		11.8	DPTS 2x100MVAr capacitor banks	11.8	10.4	22.2
2030							13.0	13.0
Total Cost		354.3	3.4	357.7		350.8	358.3	709.1
NPV (8% discount rate)		**180.6**	**2.3**	**182.9**		**156.5**	**160.7**	**317.1**

Table 11 shows that Option 4 has lower capital costs compared to the network options. However the additional cost of the energy at risk under the demand management option needs to be considered in the analysis to identify the option that maximises the net market benefit. It is noted that the option that maximises the net market benefit will not necessarily be the option with the lowest project costs.

Table 11 also shows that Option 5 has the lowest capital costs for the network component of this option. However, the inclusion of the generation costs in Option 5 produces a total cost for that option that is well above the cost of Option 4. Table 14 lists the total present value costs, including capital and operating costs, of all the options.

3.5 Results of consultation on options

Clause 5.6.2(f) requires the NSPs to consult with affected Registered Participants and interested parties on the possible options, including but not limited to demand side options, generation options and market network service options to address emerging network constraints. Accordingly, on 10 February 2012, the NSPs published a consultation paper on options to address emerging constraints in the western Melbourne metropolitan area. Interested parties were invited to lodge submissions by 26 March 2012.

No formal submissions were received, however some informal comments were made by SP AusNet regarding the proposed sizing of transformer units. Specifically, a question was raised as to whether full consideration had been given to the use of larger (225 MVA) transformers as an alternative to the proposed 150 MVA units for the recommended option (Option 1) which involves the construction of a new terminal station at Deer Park.

In response, the NSPs have evaluated the change in net market benefits that would be expected to arise if 225 MVA transformers were used in Option 1 instead of 150 MVA units as initially proposed. This further evaluation indicates that:

- Establishment of the proposed Deer Park Terminal Station by November 2016 remains the preferred option on the basis that it provides higher net market benefits than the other options considered.

- If the capital cost of a 225 MVA transformer is no more than approximately $3 million above the cost of a 150 MVA transformer, then the net market benefits of establishing the new Deer Park Terminal Station by November 2016 are likely to be increased if 225 MVA units are used instead of the 150 MVA units initially proposed.

Further details of the additional evaluation of the optimal transformer size for Option 1 are set out in section 5.4.

4 Range of Reasonable Scenarios

4.1 Regulatory test requirements

Under the market benefits limb of the regulatory test, an investment option will satisfy the test if it maximises the net present value of the market benefit, compared with a number of alternative options in a majority of reasonable scenarios. For the purpose of the test, reasonable scenarios are defined as scenarios incorporating reasonable and mutually consistent:[16]

(a) forecasts of:

(i) electricity demand (modified where appropriate to take into account demand-side options, economic growth, weather patterns and price elasticity);

(ii) the efficient operating costs of supplying energy to meet forecast demand from existing, *committed, anticipated* and *modelled proje*cts including demand side and generation projects;

(iii) the avoidable costs of *committed, anticipated* and *modelled projects* including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred;

(iv) the cost of providing sufficient ancillary services to meet the forecast demand to support the relevant option or *alternative option*; and

(v) the capital and operating costs of other regulated network and market network service projects that are augmentations consistent with the forecast demand and generation scenarios;

(b) *market development scenarios*, which must include, for each relevant option or *alternative option* :

(i) all *committed projects*;

(ii) *anticipated projects*, to the extent they are likely to be commissioned within the modelling period;

(iii) *modelled projects*; and

(iv) any other technically feasible projects identified during the consultation process; and

(c) sensitivity testing.

The rationale for assessing the costs of alternative options across a number of reasonable scenarios is to test the robustness of the results to different circumstances. Where the selection of an option may depend on particular forecasts or assumptions eventuating, it is necessary to conduct sensitivity testing against plausible variations in those forecasts or assumptions.

Given that the regulatory test considers only direct costs and benefits, market development scenarios are relevant only to the extent that they affect the nature, timing and level of such costs and benefits.

4.2 Demand forecasts and value of unserved energy

Under Clause 19(a)(i) of the regulatory test, the analysis must consider reasonable forecasts of electricity demand, modified where appropriate to take into account demand-side options, variations in economic growth, variations in weather patterns and price elasticity.

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16 See Clause 19 of the Regulatory Test. Italicised terms are defined in the regulatory test.

Forecasts of the 50th and 10th percentile summer maximum demands for the two transformer groups at KTS are presented in Figure 6 and Figure 7 below. These forecasts are consistent with those presented in AEMO's *Terminal Station Demand Forecasts 2011/12 - 2021/22*[17].

Figure 6: 10th and 50th percentile summer maximum demand forecasts KTS B1, B2 and B5 transformer group

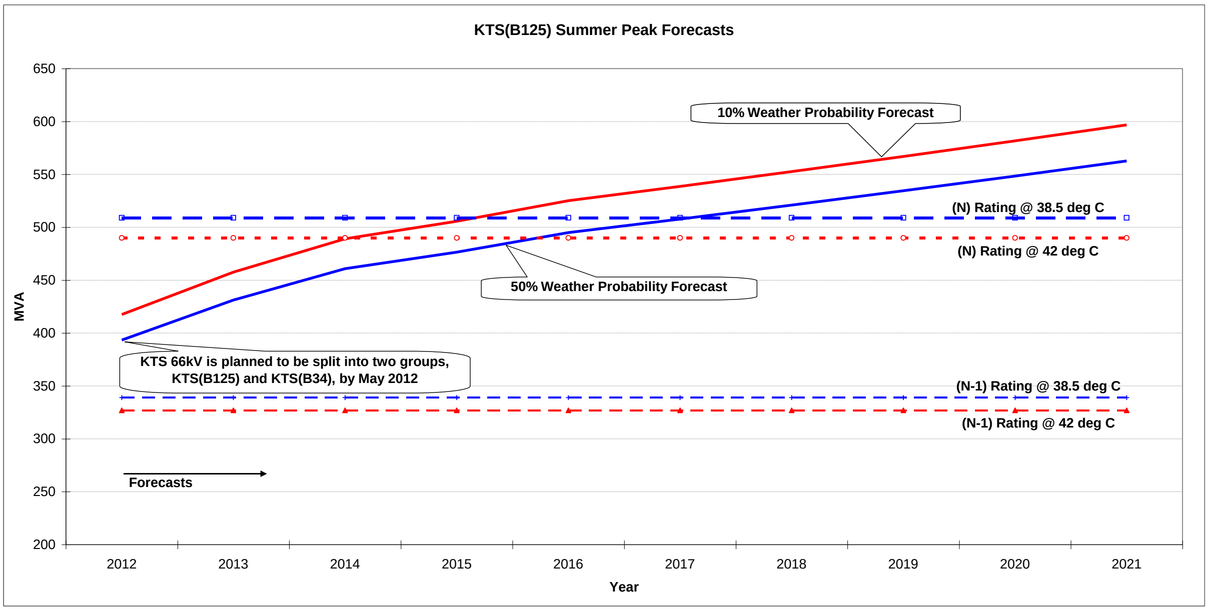
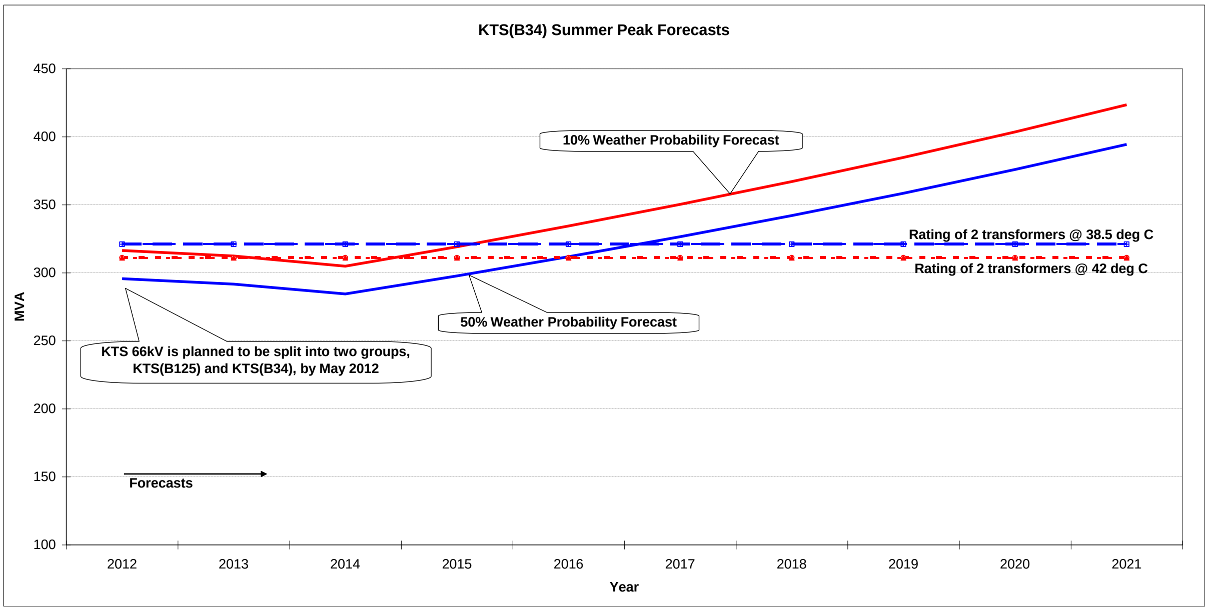


Figure 7: 10th & 50th percentile summer maximum demand forecasts KTS B3 and B4 transformer group



For the purpose of undertaking the regulatory test, the amount of unserved energy was estimated by taking a 67% weighting of expected unserved energy at the 50th percentile

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17 AEMO. "Terminal Station Demand Forecasts 2011/12 – 2021/22". Available from http://www.aemo.com.au/planning/0400-0045.pdf.

forecast and adding a 33% weighting of expected unserved energy at the 10th percentile forecast.

As already noted in section 2.2, unserved energy was valued at $60,000 per MWh. The value of unserved energy was derived from the sector value of customer reliability (VCR) values given in Table 2-1 of the 2011 Victorian Annual Planning Report, weighted in accordance with the composition of the load, by sector, at KTS.

4.3 Capital and operating costs of options

Under clause 19(a) of the regulatory test, reasonable forecasts of costs of each option under each scenario must be included in the analysis. Capital and operating cost assumptions for each of the options considered in this analysis are summarised in Table 12 below.

Table 12: Capital and operating cost assumptions

Option	Present value capital cost over study period (at 8% real discount rate)	Operating cost
"Do nothing"	Zero	Unserved energy valued at $60,000 per MWh.
Option 1	$187.4 million ± 30% in 2011 dollars, based on budget estimates provided by SP AusNet. Details of investment timing are provided in Table 7 above.	Unserved energy valued at $60,000 per MWh. Asset operating and maintenance expenditure of 1% per annum in real terms of the capital cost of the asset.
Option 2	$216.6 million ± 30% in 2011 dollars, based on budget estimates provided by SP AusNet. Details of investment timing are provided in Table 7 above.	As above.
Option 3	$204.0 million ± 30% in 2011 dollars, based on budget estimates provided by SP AusNet. Details of investment timing are provided in Table 7 above.	As above.
Option 4	$180.6 million ± 30% in 2011 dollars, based on budget estimates provided by SP AusNet. Details of investment timing are provided in Table 11 above.	As above and with demand management costs as per Table 8.
Option 5	$156.5 million ± 30% in 2011 dollars, based on budget estimates provided by SP AusNet. Details of investment timing are provided in Table 11 above.	As above and with generator support costs as per Table 8.

4.4 Market development scenarios

Under clause 19(b) of the regulatory test, reasonable market development scenarios must be considered.

In the case of this particular analysis, different assumptions regarding generation and other transmission developments are not expected to have any impact on the assessment of the alternative options to address the emerging constraints within the KTS supply area.

4.5 Sensitivity Testing

In relation to sensitivity testing, clause 23 of the regulatory test states:

> *Reasonable scenarios* under this test must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on the following, and should be appropriate to the size and type of project:
>
> (a) testing reasonable forecasts of the value of electricity to consumers.
>
> (b) price elasticity of demand.
>
> (c) capital and operating costs of *alternative options*.
>
> (d) discount rate (the lower boundary should be the regulated cost of capital).
>
> (e) market demand.
>
> (f) generation bidding behaviour using:
>
> (i) short run marginal cost; and
>
> (ii) approximates of realistic bidding.
>
> (g) commissioning dates of:
>
> (i) the option being assessed;
>
> (ii) *alternative options*;
>
> (iii) *committed projects*; and
>
> (iv) *anticipated projects*
>
> (h) inclusion or exclusion of particular *anticipated projects* based on their degree of likelihood of being commissioned within the modelling period;
>
> (i) *modelled projects* based on a market-driven market development modelling approach
>
> (j) market based regulatory instruments that may be used to address greenhouse and environmental issues and
>
> (k) other sensitivity testing determined to be relevant and material to the case concerned.

For the purpose of this analysis, it is appropriate to apply sensitivity testing to the following variables:

- demand forecasts;
- capital costs;
- operating costs;
- the value of unserved energy; and
- discount rate.

Sections 4.5.1 to 4.5.5 below provide details of the sensitivity testing undertaken in respect of these key variables.

4.5.1 Demand forecasts

For the purpose of sensitivity testing, the forecasts shown in section 4.2 were adopted as the central estimate of future demand, while a lower bound forecast was derived by reducing the annual growth rate in the central forecast by 15%.

To manage the number of scenarios presented in this study, the analysis focused on scenarios involving the central and lower bound demand forecasts.

4.5.2 Capital costs

As noted in section 4.3, SP AusNet has provided budget estimates for the augmentation works associated with each network option. Those budget estimates are subject to a range of ±30%.

Accordingly, for the purpose of sensitivity testing, a range of ±30% around the budget estimate is assumed to define the upper and lower bounds of the capital costs of all network options. A range of ±30% around the central estimate of the capital cost of the non-network options is also applied.

4.5.3 Operating costs

For the purpose of this analysis it has been assumed that the operating and maintenance costs associated with all network investments will be 1% per annum (in real terms) of the capital cost. This is a generic estimate, so sensitivity analysis has been undertaken with operating costs at ±50% of this estimate.

A range of ±50% around the central estimate of the operating cost of the non-network options is applied.

4.5.4 Value of unserved energy

As already noted, this analysis adopts a value of unserved energy of $60,000 per MWh, based on VCR data published by AEMO in the 2011 Victorian Annual Planning Report. For the purpose of sensitivity testing, the value of unserved energy is varied within limits of ±15%, giving an upper bound value of $69,000 per MWh, and a lower bound value of $51,000 per MWh.

4.5.5 Discount Rate

To compare cash flows of options with different time profiles, it is necessary to use a discount rate to express future costs and benefits in present value terms. The choice of discount rate will impact on the estimated present value of net market benefits, and may affect the ranking of alternative options.

Clause 13 of the regulatory test states:

> The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used should be consistent with the cash flows being discounted.

A real pre-tax discount rate of 8 per cent has been applied for the purpose of this analysis.

The regulatory test requires that sensitivity analysis using alternative discount rates be carried out.[18] The cost of capital allowance in the current determination applying to Victorian DNSPs is of the order of 8 per cent real pre-tax.[19] For the purpose of sensitivity testing, a lower bound real discount rate of 6 per cent is applied. An upper bound of 12 per cent real is applied.

4.5.6 Alternative timing of options

All capital projects face some risk of delay, with larger or more complex projects typically being subject to a greater risk of extensive delays. The ranking of options may be affected if there is a greater risk of delay in the delivery of one project compared to another. In light of this consideration, sensitivity analysis may examine the impact on net market benefits of options where some options are subject to materially greater risks of delay or protracted delays than others.

In this study, all options are of a similar scale and complexity so it is unlikely that there would be any material differences between options in terms of the risk of delay. For the purposes of the analysis presented in this report, therefore, it is assumed that all options involve an equal risk of delay. On this basis, no specific sensitivity analysis has been undertaken in relation to the impact of project delays on the net market benefits of the options.

A further issue arises in relation to the optimal timing of the project that is identified as maximising the net present value under the majority of scenarios examined. In particular, it is necessary to assess whether the proposed timing is optimal or, alternatively, whether further net benefits could be obtained by deferring the proposed investment.

The earliest practicable service date for a new terminal station at Deer Park is late 2016. Accordingly, under the base case assumptions adopted in this evaluation, a service date of 2016 for DPTS is adopted for Option 1. The question of the impact on net market benefits of deferring augmentation is addressed in section 5.2.

4.6 Summary of Reasonable Scenarios

In light of the approach to sensitivity testing explained in section 4.5, Table 13 below lists the variables and ranges of values for those variables adopted for the purpose of defining scenarios.

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[18] Clause 23(c) of the regulatory test.

[19] For the purpose of calculating the present value of pre-tax cash flows, the discount rate must be expressed as the “Officer” real pre-tax WACC.

Table 13: Variables and ranges adopted for the purpose of defining scenarios

Variable for sensitivity testing	Lower Bound	Base Case	Upper Bound
Annual growth rate of forecast demand	15% reduction from base (with unserved energy estimated using the same method as applied in the base case)	Central forecast (with unserved energy estimated by taking a 67% weighting of expected unserved energy at the 50th percentile forecast and adding a 33% weighting of expected unserved energy at the 10th percentile forecast)	N/A
Capital cost	Budget estimates minus 30% NSP estimate minus 30%	SPI PowerNet budget estimate for network options NSP estimate for non-network options	Budget estimates plus 30% NSP estimate plus 30%
Network operating costs	0.5% per annum of capital cost	1% per annum in real terms of capital cost	1.5% per annum of capital cost
Non-network option operating costs	NSP estimate minus 50%	NSP estimate	NSP estimate plus 50%
Value of unserved energy (VCR)	$51,000/MWh	$60,000/MWh	$69,000/MWh
Discount rate (real pre-tax)	6%	8%	12%

Clause 19 of the regulatory test requires the application of reasonable scenarios incorporating reasonable and mutually consistent forecasts of demand, costs and market development paths. In light of this requirement, the analysis presented in section 5:

- assesses the sensitivity of the base case[20] net market benefit of the proposed option to upper and lower bound variations in each individual variable, as shown in Table 13; and also

- evaluates the net market benefit of the proposed option under six scenarios that represent plausible combinations of assumptions.

[20] "Base case" denotes the use of central assumptions for all variables.

5 Methodology and results of analysis

5.1 Methodology and approach

In order to evaluate the net market benefits of each option, a discounted cash flow model was constructed. The total costs (comprising capital and operating expenditure, and expected unserved energy costs[21]) of the five options and the "Do nothing" option were evaluated over the 19 year study horizon[22], using central estimates of all key variables. This initial evaluation enabled the net market benefits of all options, relative to the "do nothing" option, to be established.

From this evaluation, Option 1 was selected as the "reference case" and the net market benefits of the other options, relative to the reference case, were then evaluated. This approach facilitates the identification of the option that maximises net market benefits, in accordance with the requirements of the regulatory test.

5.2 Results of the analysis

Table 14 shows the estimated net market benefits of Options 1, 2, 3, 4 and 5, relative to the "Do nothing" option over the period from 2012 to 2030, using central estimates for all variables.

Table 14: Summary of results – Base case cost-benefit analysis
(Net market benefits relative to the "Do nothing" option in present value terms in $ million)

	Total market benefit	Total cost	Net market benefit
Option 1	17,322	200	17,122
Option 2	17,311	230	17,081
Option 3	17,319	217	17,102
Option 4	17,309	194	17,115
Option 5	17,321	326	16,995

These results indicate the substantial net market benefits – in the form of large reductions in expected unserved energy – delivered by all options, relative to the "Do nothing" option. The results show that, assuming central estimates for all key variables, Option 1 delivers the highest net market benefits.

Table 15 shows the results of the comparative analysis of the options, relative to Option 1. "Base case" denotes the use of central assumptions for all variables. The net market benefit of each option (relative to Option 1) under the base case scenario is shown in the first row of the table, and then results are presented reflecting the base case changed for one variable only (in turn: demand growth rate, capital cost, network operating costs, value of customer reliability and discount rate). The shaded cell in each row indicates the option that maximises net market benefit for that particular set of assumptions.

21 The methodology for estimating the volume of expected unserved energy is explained in section 4.2.

22 Refer to section 3.2 for an explanation of the rationale for selection of the study horizon.

Table 15: Summary of results- Sensitivity testing of individual variables (Net market benefits relative to Option 1 in present value terms in $ million)

	Option 1	Option 2	Option 3	Option 4	Option 5
Base Case	**0**	**-41.3**	**-20.6**	**-7.5**	**-127.3**
Demand forecast sensitivity					
Lower bound (base annual growth rate reduced by 15%)	0	-29.6	-29.5	-0.5	-95.1
Capital cost sensitivity					
Upper Bound (Base + 30%)	0	-50.4	-25.8	-5.2	-116.9
Lower Bound (Base - 30%)	0	-32.2	-15.3	-9.8	-137.7
Operating cost sensitivity					
Upper Bound (Base + 50%)	0	-42.0	-21.0	-7.0	-125.4
Lower Bound (Base - 50%)	0	-40.7	-20.1	-7.9	-129.1
Value of customer reliability					
Upper Bound ($69,000 / MWh)	0	-42.3	-21.0	-9.2	-126.8
Lower Bound ($51,000 / MWh)	0	-40.3	-20.1	-5.7	-127.7
Discount rate sensitivity					
Upper Bound (12% real)	0	-25.9	-13.6	-3.4	-75.0
Lower Bound (6% real)	0	-52.0	-25.4	-10.1	-164.4

Examination of the sensitivity of net market benefits to changes in individual variables (shown in Table 15) is a precursor to full sensitivity testing involving different combinations of assumptions on all key variables. Table 15 shows that Option 1 is consistently the superior option when changes to individual variables are considered.

Table 16 sets out a comparison of the present value of net market benefits of each option (relative to Option 1) when different combinations of assumptions are applied under different scenarios. It is noted that none of the scenarios contain an upper bound discount rate assumption. This is because the results of sensitivity testing of this parameter (shown in Table 15) indicate that increasing the discount rate does not affect the relative ranking of Options 1, 2, 3, 4 and 5.

The yellow shaded cell in each row indicates the option that maximises net market benefit for that particular scenario.

Table 16: Results- Economic evaluation of options under various scenarios (Net market benefits relative to Option 1 in present value terms in $ million)

Scenario	Option 1	Option 2	Option 3	Option 4	Option 5
Base Case	**0**	**-41.3**	**-20.6**	**-7.5**	**-127.3**
Scenario A • Central demand growth • Upper bound capital cost • Upper bound operating cost • Central VCR estimate • Central discount rate	0	-51.3	-26.4	-4.6	-114.4
Scenario B • Central demand growth • Upper bound capital cost • Upper bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-63.6	-32.0	-5.6	-152.5
Scenario C • Central demand growth • Lower bound capital cost • Lower bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-38.5	-18.0	-10.4	-176.0
Scenario D • Lower bound demand growth • Upper bound capital cost • Upper bound operating cost • Central VCR estimate • Central discount rate	0	-36.6	-38.9	2.4	-78.8
Scenario E • Lower bound demand growth • Upper bound capital cost • Upper bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-48.2	-46.0	1.0	-114.2
Scenario F • Lower bound demand growth • Lower bound capital cost • Lower bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	-28.9	-24.0	-3.9	-144.5

The results set out in Table 15 and Table 16: show that:

- Option 1 maximises net market benefit under the base case set of assumptions; and
- Option1 maximises net market benefits in the majority of sensitivity tests and scenario analyses involving the variation of assumptions within plausible limits.
- Option 4 only provides maximum benefits if there is a combination of lower demand growth and higher capital cost. This indicates that if demand is 15% per annum less than forecast and capital costs are 30% higher, there may be scope for deferring the DPTS project for one year.

Clause 23(g) of the regulatory test states that sensitivity testing should be carried out in relation to the commissioning dates of the proposed option and alternative options. In developing each option, the timing has been chosen to maximise the net market benefit of that option. The proposed timing has been tested by examining the financial impact of deferring each option by 1 year. The analysis has confirmed that each option is timed optimally because:

- deferring the augmentation for one year would lead to cost-savings; however
- the cost of deferring each option (in terms of expected unserved energy) exceeds the savings in project cost (in present value terms) because the volume of expected unserved energy increases sharply each year in the absence of any action to increase network capacity.

Table 17 shows the impact on net market benefits of deferring the proposed augmentation by one year.

Table 17: Summary of results- Impact of deferral of augmentation (Net market benefits in present value terms in $ million)

Option	Net Market benefits with base forecast (relative to "do nothing")		Change in net market benefit due to 1 year deferral
	2016 implementation	Defer implementation for 1 year	
"Do nothing"	Zero	Zero	Zero
Option 1	17,122	17,111	-11
Option 2	17,081	17,068	-13
Option 3	17,102	17,089	-13
Option 4	17,115	17,095	-20
Option 5	16,995	16,981	-14

The analysis presented above confirms that under base case assumptions:

- Option 1 has the highest net market benefit of all network options, regardless of whether the augmentation is delivered in 2016 or deferred for one year; and
- commissioning Option 1 in 2016 will maximise net market benefits.

As discussed in section 2, the driver of the proposed augmentation is demand growth and hence the net market benefits of the options are sensitive to the assumptions regarding forecast demand growth. As noted in section 4.5.1, the analysis presented in this report has considered two demand forecasts:

- a central case, which is, in effect, a composite of the 10th and 50th percentile demand forecasts; and
- a lower bound case in which the annual growth in demand is 15% lower than the central case.

Table 18 shows the impact the reduced demand sensitivity has on net market benefits under a 2016 implementation time frame and with a one year deferral of the proposed augmentation.

Table 18: Summary of results- Impact of reduced demand sensitivity (Net market benefits in present value terms in $ million)

Option	Net Market benefits with reduced demand forecast (relative to "do nothing")		Change in net market benefit due to 1 year deferral
	2016 implementation	Defer implementation for 1 year	
"Do nothing"	Zero	Zero	Zero
Option 1	5,088	5,084	-4
Option 2	5,058	5,052	-6
Option 3	5,058	5,053	-5
Option 4	5,087	5,079	-8
Option 5	4,993	4,985	-8

The analysis presented above confirms that even with reduced demand forecasts – a reduction of 15% from the annual growth rate assumed in the base case:

- Option 1 has the highest net market benefit of all network options, regardless of whether the augmentation is delivered in 2016 or deferred for one year; and
- commissioning Option 1 in 2016 will maximise net market benefits.

5.3 Qualitative analysis of relevant considerations

The economic evaluation of net market benefits has demonstrated that Option 1 is the superior option. In addition, it also provides the following benefits that have not been quantified during the joint planning process:

- Option 1 requires the lowest amount of new line work construction in established residential and parkland areas, thereby reducing community and environmental impacts; and
- Option 1 places transformation capacity closer to the load earlier than other options, and therefore delivers additional benefits in terms of reduced losses.

5.4 Further evaluation to identify optimal transformer size for Option 1

As noted in section 3.5, the NSPs have evaluated the change in net market benefits that would be expected to arise if 225 MVA transformers were used in Option 1 instead of 150 MVA units as initially proposed.

Overall, the economic benefit of using three 225 MVA transformers as opposed to four 150 MVA units is dependent on the cost difference between the different units, the residual energy at risk and the amount of downstream asset investment required under alternative approaches employing either 225 MVA or 150 MVA units. It is noted that while the cost of a

225 MVA transformer is expected to be higher than that of a 150 MVA transformer, the use of 225 MVA units would deliver cost savings in terms of reductions in the level of 220 kV and 66 kV plant requirements. Moreover, if two 225 MVA transformers are installed, the need for a third transformer at DPTS would be deferred (from 2018 under the 150 MVA development scenario, to 2023 if 225 MVA units are used).

Long term economic studies using the methodology outlined in section 5.1 indicate that the net market benefit of Option 1 would be increased by $0.6 million if 225 MVA transformers are used instead of 150 MVA units, assuming that the cost of each 225 MVA unit is $3 million greater than the cost of a 150 MVA unit.

At the time of preparing this report, there is uncertainty regarding the cost of 225 MVA units, so the net market benefits of using 225 MVA transformers have been evaluated over three different capital cost assumptions (or “cases”), as shown in the table below.

Table 19: Capital cost assumptions for 225 MVA transformers

Case	Capital cost of each 225 MVA transformer
Case (a)	The installed cost of a 150 MVA transformer ($7.1 million) plus $2 million.
Case (b)	The installed cost of a 150 MVA transformer ($7.1 million) plus $3 million.
Case (c)	The installed cost of a 150 MVA transformer ($7.1 million) plus $4 million.

The table below shows the change in net market benefits (compared to Option 1) arising from the use of 225 MVA transformers, under the three 225 MVA transformer cost cases described above, and applying the sensitivity tests described in section 4.5.

Table 20: Summary of results- Sensitivity testing of individual variables
(Net market benefits relative to Option 1 in present value terms in $ million)

	Option 1: 150 MVA at DPTS	Case (a): 225 MVA at extra cost of $2million/unit	Case (b): 225 MVA at extra cost of $3million/unit	Case (c): 225 MVA extra cost of $4million/Unit
Base Case	**0**	**2.7**	**0.6**	**-1.4**
Demand forecast sensitivity				
Lower bound (Base case growth rate lowered by 15% pa)	0	1.4	-0.7	-2.7
Capital cost sensitivity				
Upper Bound (Base + 30%)	0	3.7	1.1	-1.6
Lower Bound (Base - 30%)	0	1.6	0.2	-1.2
Operating cost sensitivity				
Upper Bound (Base + 50%)	0	2.8	0.7	-1.5
Lower Bound (Base - 50%)	0	2.6	0.6	-1.4
Value of customer reliability				
Upper Bound ($69,000 / MWh)	0	2.5	0.5	-1.5
Lower Bound ($51,000 / MWh)	0	2.8	0.8	-1.3
Discount rate sensitivity				
Upper Bound (12% real)	0	2.1	0.4	-1.2
Lower Bound (6% real)	0	3.1	0.8	-1.5

Sensitivity testing indicates that if the cost of each 225 MVA unit is no more than approximately $3 million greater than the cost of a 150 MVA transformer, then the use of 225 MVA transformers at DPTS will maximise net market benefits except where the lower bound demand forecast assumption is applied.

The results of scenario analysis (using the scenarios described in section 4.6) are set out in the table below.

Table 21: Summary of results - Economic evaluation of options under various scenarios (Net market benefits relative to Option 1 in present value terms in $ million)

Scenario	Option 1	Case (a)	Case (b)	Case (c)
Base Case	**0**	**2.7**	**0.6**	**-1.4**
Scenario A • Central demand growth • Upper bound capital cost • Upper bound operating cost • Central VCR estimate • Central discount rate	0	3.9	1.1	-1.6
Scenario B • Central demand growth • Upper bound capital cost • Upper bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	4.7	1.6	-1.5
Scenario C • Central demand growth • Lower bound capital cost • Lower bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	1.9	0.4	-1.2
Scenario D • Lower bound demand growth • Upper bound capital cost • Upper bound operating cost • Central VCR estimate • Central discount rate	0	2.0	-0.8	-3.5
Scenario E • Lower bound demand growth • Upper bound capital cost • Upper bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	2.8	-0.3	-3.4
Scenario F • Lower bound demand growth • Lower bound capital cost • Lower bound operating cost • Lower bound VCR estimate • Lower bound discount rate	0	1.2	-0.3	-1.9

The results set out above show that in the majority of reasonable scenarios, the installation of 225 MVA transformers instead of 150 MVA transformers at the proposed Deer Park

Terminal Station will maximise net market benefits. In view of this, the NSPs propose to construct Deer Park Terminal Station using 225 MVA transformers. It is noted however, that the cost-benefit difference between the use of 150 MVA or 225 MVA transformers is marginal and, depending on the incremental cost to install 225 MVA transformers, could still go either way.

If, during the course of progressing the detailed design of the project, it becomes evident that the 150 MVA alternative is more likely to maximise net market benefit, then the NSPs may revert to that network option.

6 Conclusion

The 220/66 kV transmission connection assets at Keilor Terminal Station (KTS) and the 66 kV lines to Sunbury zone substation (SBY) are heavily loaded and require significant augmentation. Various options, including non-network solutions, have been evaluated through a joint planning process conducted by AEMO, Jemena and Powercor to address the emerging transmission connection and distribution system constraints.

The studies demonstrate that the option of establishing a new Deer Park Terminal Station (DPTS) and associated sub-transmission lines, with an optimal timing of November 2016, will maximise net market benefits under a range of reasonable scenarios. The impact on net market benefits of deferring the proposed augmentation was examined. This examination confirmed that in both the base case and with significantly reduced demand forecasts:

- deferral of augmentation beyond the proposed commissioning date of November 2016 would reduce net market benefits; and
- commissioning of the proposed new DPTS in November 2016 will maximise net market benefits.

The NSPs have, in accordance with clause 5.6.2(f) of the Rules, consulted on the possible options to address the emerging network constraints in the western Melbourne metropolitan area. Although no formal submissions were received from interested parties, informal comments led the NSPs to evaluate the net market benefit of installing 225 MVA transformers at DPTS instead of the 150 MVA units proposed initially. The further evaluation conducted by the NSPs confirms that the establishment of DPTS and associated sub-transmission lines by November 2016 remains the preferred option, however, the installation of larger 225 MVA transformers is likely to maximise net market benefits.

Accordingly, the proposed project involves constructing a new terminal station at Deer Park (DPTS) with two 225 MVA 220/66 kV transformers and six 66 kV exits by November 2016. However, if, during the course of progressing the detailed design of the project, it becomes evident that the 150 MVA alternative is more likely to maximise net market benefit, then the NSPs may revert to that network option.

The proposed Deer Park terminal station location is on an existing undeveloped site owned by SP AusNet, at the corner of Christies Road and Riding Boundary Road, Ravenhall. The zoning of this site is Special Use Zone – Schedule 3 (SUZ3). This zoning type is used to provide areas to be used for the purposes of essential service utility installations. The site is located directly underneath the path of existing 220 kV transmission lines and no additional transmission lines or easements are required at this stage.

The key elements of the proposed project also include:

- Connection of DPTS to the Keilor Terminal Station (KTS)-Geelong Terminal Station (GTS) No. 2 220 kV line.

- Connection to DPTS of a new zone substation Truganina (TNA) at 66/22 kV.
- Transferring 66/22 kV zone substations Melton (MLN) and Sunshine (SU) to DPTS, and the construction of a second KTS to Sunbury zone substation (SBY) 66 kV line to relieve overloads at KTS and on the existing KTS-SBY, KTS to Sydenham zone substation (SHM) and KTS-MLN 66 kV looped lines.

The proposed configuration of the network in 2016, following commissioning of the new Deer Park Terminal Station, is shown in Appendix 1.

The proposed works have no material inter-network impact, so an augmentation technical report is not required to be included with this document.

7 Next steps

In accordance with the provisions set out in clause 5.6.2(i) of the Rules, Registered Participants may, within 40 business days after the publication of this report, dispute the recommendation set out in this report. Accordingly, Registered Participants who wish to dispute the recommendation outlined in this report must do so by 27 June 2012. Any Registered Participants raising such a dispute are also asked to notify the officer identified below.

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Appendix 1: Network configuration following commissioning of DPTS in 2016