Market benefits assessment for network upgrades in Western Victoria

TransGrid

14 July 2017

Notice

Ernst & Young was engaged on the instructions of TransGrid (“TransGrid”) to provide a market benefits assessment (the "Services"), in relation to nine different network development scenarios provided by TransGrid to facilitate new entrant generation in the Victorian region of the National Electricity Market (the “Project”).

The results of Ernst & Young’s work, including the assumptions and qualifications made in preparing the report, are set out in Ernst & Young's report dated 14 July 2017 ("Report"). The Report should be read in its entirety including the cover letter, the applicable scope of the work and any limitations. A reference to the Report includes any part of the Report. No further work has been undertaken by Ernst & Young since the date of the Report to update it.

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14 July 2017

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Market benefits assessment for network upgrades in Western Victoria

In accordance with the Engagement Agreement dated 8 May 2017 and pursuant to the terms and conditions of Panel Q26/14 (the "Agreement"), Ernst & Young ("we" or "EY") has been engaged by TransGrid ("you" or the "Client") to provide a market benefits assessment (the "Services") in relation to nine different network development scenarios provided by TransGrid to facilitate new entrant generation in the Victorian region and of the National Electricity Market (the "Project").

The enclosed report (the "Report") sets out the outcomes of our work. You should read the Report in its entirety. A reference to the report includes any part of the Report.

Purpose of our Report and restrictions on its use

Please refer to a copy of the Agreement for the restrictions relating to the use of our Report. We understand that the deliverable by EY will be used for the purpose of assisting TransGrid in its investigation into the relative merits of different network options in relation to market benefit analysis and benefits in the National Electricity Market (the "Purpose").

This Report was prepared on the specific instructions of TransGrid solely for the Purpose and should not be used or relied upon for any other purpose.

We accept no responsibility or liability to any person other than to TransGrid or to such party to whom we have agreed in writing to accept a duty of care in respect of this Report, and accordingly if such other persons choose to rely upon any of the contents of this Report they do so at their own risk.

Nature and scope of our work

The scope of our work, including the basis and limitations, are detailed in our Agreement and in this Report.

Our work commenced in May 2017 and was completed on 14 July 2017. Therefore, our Report does not take account of events or circumstances arising after 14 July 2017 and we have no responsibility to update the Report for such events or circumstances.

Limitations

This modelling considers a number of combinations of input assumptions relating to future conditions, which may not necessarily represent actual or most likely future conditions. Additionally, modelling inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility for the achievement of projected outcomes, if any.

We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Our conclusions are based, in part, on the assumptions stated and on information provided by TransGrid during the course of the engagement. The modelled outcomes are contingent on the collection of assumptions as agreed with TransGrid and no consideration of other market events, announcements or other changing circumstances are reflected in this Report. Neither Ernst & Young nor any member or employee thereof undertakes responsibility in any way whatsoever to any person in respect of errors in this Report arising from incorrect information provided by TransGrid.

In the preparation of this Report we have considered and relied upon information from a range of sources believed after due enquiry to be reliable and accurate. We have no reason to believe that any information supplied to us, or obtained from public sources, was false or that any material information has been withheld from us. We do not imply and it should not be construed that we have verified any of the information provided to us, or that our enquiries could have identified any matter that a more extensive examination might disclose.

This letter should be read in conjunction with our Report, which is attached.

Thank you for the opportunity to work on this project for you. Should you wish to discuss any aspect of this Report, please do not hesitate to contact Ian Rose on 0419 729 584 or Michael Fenech on 07 3011 3333.

Yours sincerely

Ian Rose
Executive Director

Michael Fenech
Partner

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1. Executive summary

EY has been engaged by TransGrid to assess potential market benefits associated with a range of network development scenarios that strengthen the transmission network in the National Electricity Market ("NEM"). The network development scenarios proposed by TransGrid involve a combination of intra-regional and inter-regional network reinforcement with the aim to facilitate connection of additional renewable generation projects in Western Victoria whilst also providing additional market benefits.

The key objective of EY's analysis is to provide an understanding of the magnitude of market benefits that could be attributed to the different network development scenarios provided by AEMO, TransGrid and other relevant parties relative to a base case 'business-as-usual' ("BAU") scenario.

EY understands that the assessment performed here will be used by TransGrid internal management to assess network investment options that may be progressed under a future Regulatory Investment Test ("RIT-T"). EY has not been provided the capital cost estimates for the network development scenarios and has not assessed whether there may be sufficient net benefit to warrant progressing a RIT-T, or whether there is sufficient net benefit to pass a RIT-T. EY has undertaken electricity market modelling to help inform TransGrid's own internal assessment.

The modelling period extends from 2018-19 to 2049-50.

A total of nine network development scenarios (inclusive of a BAU scenario) has been provided by TransGrid which are categorised into a number of broad strategic themes, described below:

- "Do nothing, no network augmentation, business-as-usual"
- "Additional interconnection between New South Wales and Victoria"
- "Intra-regional Victorian network reinforcement"
- "Victorian network reinforcement with interconnection to South Australia or New South Wales".

A full list of the specific network augmentations associated with each theme is provided in Appendix B. These augmentations may include construction of additional bulk transmission line circuits, bulk transformers at key supply points and inter-regional ac interconnectors. The network development scenarios provided by TransGrid are planned to be commissioned in either 2021 or 2023 based on estimated lead times.

The key outcome of this analysis is shown in Table 1 (following page). Table 1 shows the Net Present Value ("NPV") of market benefits[1] compared to the BAU scenario for each network development scenario. The values represent the potential market benefits that may be released in the NEM as a result of undertaking the network augmentation options. The benefits are discounted to 1 July 2018 using a 7.5% discount rate. The values presented in Table 1 do not include consideration of the capital costs associated with the network reinforcement.

All outcomes are based on the assumptions stated and on information provided by TransGrid and from other third party sources. The modelled outcomes are forecasts contingent on the collection of assumptions as agreed with TransGrid and no consideration of other market events, announcements or other changing circumstances are reflected in this Report.

[1] Market benefits represent the change in fuel, operations and maintenance, fixed, capital, and emissions costs between each interconnection option and the business-as-usual scenario. NPVs are calculated using an indicative 7.5% discount rate.

Table 1: Summary of outcomes

Scenario[2] Reference	Strategic Theme	Brief Description	NPV of market benefits including carbon ($m)	NPV of market benefits excluding carbon ($m)
Scenario 1	Business-as-usual	No network augmentation Do Nothing	-	-
Scenario 2	Additional interconnection between New South Wales and Victoria	Victoria to New South Wales 330 kV Single Circuit Reinforcement	193	191
Scenario 3		Victoria to New South Wales 330 kV Double Circuit Reinforcement	282	270
Scenario 5		Victoria to New South Wales 330 kV Double Circuit Reinforcement with Western Victoria 500 kV and 220 kV reinforcement	617	593
Scenario 6		Snowy to South Morang 330 kV Reinforcement	282	269
Scenario 4	Intra-regional Victoria network reinforcement	Western Victoria 500 kV, 220 kV Reinforcement	602	563
Scenario 9		Subset of Scenario 4	539	487
Scenario 7	Victoria network reinforcement with interconnection to South Australia and New South Wales	Scenario 5 plus NSW-SA Interconnector	923	928
Scenario 8		Scenario 5 plus VIC-SA Interconnector	909	905

The following key findings are made as a result of this work[3].

Finding 1: Options that involved interconnection to other states whilst still augmenting the intra-regional Victorian network showed highest potential for market benefits

Options that involve additional interconnection from Victoria to South Australia or New South Wales, together with intra-regional network reinforcement in Victoria, produced the highest market benefits. Each of these showed market benefits in excess of $900 M, driven by potential reductions in capital costs. The additional inter-regional power flows and the ability to share cheap generation across regions resulted in less generation capacity being built across the NEM. However, whilst EY has not been provided with network capital cost estimates, it is likely that network development scenarios under these themes will be the most expensive from a capital cost perspective.

Finding 2: All network development scenarios have potential for benefit in excess of $200 M

The analysis showed that all of the network development scenarios provided by TransGrid have the potential for market benefits in the order of $200 M and more[4]. These benefits are driven mainly by potential capital cost reductions derived from the installation of less generation capacity to meet the Victorian renewable energy target[5] ("VRET"). The additional network capacity reduces transmission network congestion, increasing the amount of renewable energy able to be dispatched from this region. This results in less generation required to meet the VRET. Second order benefits were

[2] The network option reference refers to original options provided by TransGrid. They have been included for ease of referencing and kept to the original convention. This means that options are not categorised in a sequential manner.

[3] It should be noted that this scope of work has not considered the impact of Snowy 2.0. Further work would be needed to assess the potential for additional benefits as a result of its inclusion in the generation development plan.

[4] Scenario 2 has estimated market benefit of $193 M, but may exceed $200 M after the inclusion of other potential classes of market benefts. Other scenarios may also result in increased benefit as a result of additional classes.

[5] For the purposes of this modelling, it has been assumed that the renewable energy target is defined as an energy production target (as opposed to an installed capacity target), as agreed with TransGrid.

derived from fuel cost savings as well as reduced fixed operational and maintenance costs as a result of less generation installed.

Finding 3: The network augmentations based on AEMO's PSCR broadly align with initial modelling performed by AEMO

The network development plans provided by TransGrid in Scenario 4 and 9 were based on options discussed in AEMO's Western Victoria Renewable Integration Project Specification Consultation Report ("PSCR"). These options focused on intra-regional network upgrades of the 500 kV and 220 kV networks in Victoria. No inter-regional network reinforcements were proposed in these scenarios.

AEMO's PSCR states the potential for market benefits in the range of $300-$500 M driven solely from a reduction in variable generation costs. EY's modelling, which takes into account more than just variable cost savings, indicates network augmentations similar to those provided in AEMO's PSCR, may provide market benefits exceeding $500 M. Whilst AEMO's modelling is centred on variable cost savings, EY's modelling considers total system costs and shows there is potential for benefits associated with reductions in capital costs as well.

Finding 4: Network development scenarios that focused solely on additional interconnection between north-west Victoria and south-west New South Wales (Scenario 2 and Scenario 3) resulted in less market benefits

Network development scenarios that did not include any upgrades to the Western Victorian 220 kV network showed less potential for market benefits. Potential for market benefits for these options were in the order of $200-$300 M. The intention of these reinforcements is to provide an export point from the 220 kV network from Western Victoria into the New South Wales region through a new Kerang 330/220 kV transformer. However, without some upgrades in the Western Victorian network as well, the power flows onto the new interconnector are limited by the 220 kV transmission network. It is noted that these scenarios may still provide net market benefits depending on the capital cost of the network development, and may facilitate a staged development approach which leads to a more complete network solution as modelled in Scenarios 5, 7 and 8.

Finding 5: The benefits associated with reinforcing the 330 kV network between Snowy and South Morang are derived from variable cost savings

Reinforcing the 330 kV network between Snowy and South Morang did not alter the generation planting in Victoria significantly. Rather, the market benefit for this option was driven by providing New South Wales with strong access to cheaper Victorian generation as well as reductions in Victorian OCGT generation. This resulted in large fuel cost savings as a result of cheaper Victorian generation displacing New South Wales generation and reduced gas usage. Reinforcing the 330 kV network between Snowy and South Morang alone did not alter the generation planting in Victoria as no network augmentation was performed on the 220 kV network resulting in congestion still remaining in that region. As such, capital cost savings were not identified. It should be noted that Snowy 2.0 was not included in the generation development plan under this scenario. Additional work to determine the impact of Snowy 2.0 on the potential for market benefits may be part of further detailed investigations.

Modelling Considerations

Capital investment in the BAU scenario is essentially driven by market signals, taking into consideration profitability and system reliability. Market benefits associated with the network development scenarios are calculated relative to the BAU scenario.

It is recognised that investment decisions are not exclusively based on economic market theory. In reality, market signals may not always be timely and clear enough for the market to respond in an orderly, controlled and efficient manner. Regulatory uncertainty and government intervention are complicating factors. As such, the modelling may understate potential future congestion and thus the economic benefit that might be realised from the network augmentation.

Additionally, RIT-T assessments typically involve the assessment of network investment across multiple market scenarios. This provides demonstrable justification that the network investment produces sufficient net benefit against a wide variety of potential prevailing market outcomes. These scenarios may typically include the assessment of high impact low probability (“HILP”) events (e.g. “N-2”, interconnector outages) in addition to other modelling sensitivities to capture market volatility and extreme pricing periods. This assessment has not been performed here.

The assessment performed here is broader in scope, modelling nine different network development scenarios under a single set of market assumptions. As such, the modelling performed here may result in different market benefits being captured compared to the detailed assessments performed during the preparation of the Project Assessment Draft Report in the RIT-T Process.

2. Introduction

EY has been engaged by TransGrid to assess potential market benefits associated with a range of network development scenarios that strengthen the transmission network in the National Electricity Market ("NEM"). The network development scenarios proposed by TransGrid involve a combination of intra-regional and inter-regional network reinforcement with the aim to facilitate connection of additional renewable generation projects in Western Victoria whilst providing additional market benefits.

EY understands that the assessment performed here will be used by TransGrid internal management to assess network investment options that may be progressed under a future Regulatory Investment Test ("RIT-T"). In performing this assessment, EY has not considered the relative capital cost component of each network augmentation option and specifically whether there may be sufficient net benefit to justify a RIT-T under the National Electricity Rules ("NER").

This analysis may also be used by TransGrid to assist in a submission to the Australian Energy Market Operator's ("AEMO") public consultation on its Western Victoria Project Specification Consultation Report (the "PSCR")[6], which is seeking feedback on credible network and non-network options in response to potential 220 kV network congestion.

2.1 AEMO's Western Victoria PSCR

AEMO have a delegated responsibility for the transmission network planner role in Victoria. AEMO's 2017 Victorian Annual Planning Report[7] discusses the potential for new renewable generation capacity to connect driven by the Victorian renewable energy target ("VRET").

In June 2016, the Victorian Government committed to achieving a state based renewable energy target of 25% by 2020 and 40% by 2025[8]. The scheme is specifically designed to connect 5400 MW of large scale renewable energy capacity by 2025[8]. This has resulted in significant interest in the connection of renewable projects in Victoria.

AEMO states that more than 5000 MW of connection applications and enquiries have been received for the Western Victorian region, with approximately 80% of this capacity seeking to connect to the 220 KV and 66 kV networks, with the remaining 20% seeking connection at 500 kV[6].

The amount of renewable capacity seeking connection into the transmission network is likely to cause network congestion as a result of network constraints on the 500 kV, 220 kV and 66 kV transmission networks. The majority of congestion is likely to be on the 220 kV[9].

AEMO states that these network limitations may have the impact of constraining off cheaper renewable generation resulting in inefficient dispatch outcomes and ultimately leading to increased wholesale electricity prices and increased prices for consumers in the long term. Relieving network congestion (by building additional network capacity) may result in relieving these limitations and release cheaper renewable generation to be dispatched[9].

TransGrid is seeking to understand the potential for market benefits as a result of additional interconnection between New South Wales and Victoria and how the VRET may impact these outcomes.

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[6] Western Victoria Renewable Inetegration – Project Specification Consultation Report – April 2017, Pg.7

[7] AEMO Victorian Annual Planning Report 2017, Pg.36

[8] https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets

[9] Western Victoria Renewable Inetegration – Project Specification Consultation Report – April 2017

2.2 Report structure

This Report outlines the methodology and key input assumptions that have been applied in this modelling, including the approach taken to assessing market benefits under the RIT-T framework.

This Report also presents the outcomes of the modelling and provides an analysis of the drivers of market benefits across the range of network development scenarios considered.

All outcomes are based on the assumptions stated and on information provided by AEMO, TransGrid and from other third party sources. The modelled outcomes are forecasts contingent on the collection of assumptions as agreed with TransGrid and no consideration of other market events, announcements or other changing circumstances are reflected in this Report.

The Report is structured as follows:

- Section 3 outlines the methodology and input assumptions applied in the modelling.
- Section 4 provides an analysis of the modelling outcomes.
- Section 5 summarises the categories of market benefit that have not been assessed through market modelling.

All dollar values in this Report are June 2018 real Australian dollars, rounded to the nearest whole dollar, unless otherwise stated.

3. Methodology and input assumptions

3.1 Input assumptions

The following assumptions were used in our modelling:

- Annual energy and peak demand forecasts from the AEMO National Electricity Forecasting Report 2016 Neutral scenario[10], extrapolated linearly to 2049-50.
- Capital costs from the NTNDP 2016, originally based on the CO2CRC Australian Power Generation Technology Report[11], extrapolated linearly to 2049-50.
- Fuel costs from the AEMO Planning assumptions and NTNDP 2016[12,13]. Beyond the timeframe of the costs provided, fuel costs are held constant.
- The introduction of renewable generation in Victoria required to meet the targets specified by the Victorian State Government[14].
- Network development is based on the scenarios provided by TransGrid and assumed in-service based on specified timings. No other network options are modelled beyond those specified by TransGrid.

These assumptions were selected by TransGrid and sourced from the public sources published by third parties as indicated above. Different assumptions would lead to different forecast outcomes.

Emissions abatement

The Australian Government has committed to reducing emissions by between 26-28% below 2005 levels by 2030[15]. The modelling in this report assumes that the electricity generation sector contributes to this target. There are many policy options that could drive the achievement of this target. Our initial modelling assumed[16] that the application of some form of pricing on carbon emissions assists in driving the planning and operational decisions required for the electricity sector to meet its share of the 2030 reduction requirement.

A carbon price of $30/t CO_2-e was introduced into the modelling from the 2030 study year.

Variation of input assumptions could vary the carbon price required to achieve the target emissions reduction and drive different modelled outcomes. Alternative mechanisms of achieving Australia's emissions reduction target or a variation in the target or the electricity sector's share of the target would also drive different outcomes.

The modelling values differences in carbon emissions relative to the BAU scenario at the price of carbon applied in that year. For the purpose of assessing the market benefit of reduced emissions there are two applicable methodologies:

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10 Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report

11 Available at: http://www.co2crc.com.au/wp-content/uploads/2016/04/LCOE_Report_final_web.pdf

12 *February 2016 Gas Pricing Consultancy Databook (Core Energy Group)*. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

13 *2016 Coal Cost Data (Wood Mackenzie)*. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

14 1,500 MW of new large-scale renewable energy capacity by 2020 and up to 5,400 MW by 2025 as described here: http://www.delwp.vic.gov.au/energy/renewable-energy/victorias-renewable-energy-targets

15 https://www.environment.gov.au/climate-change/publications/factsheet-australias-2030-climate-change-target

16 As agreed with TransGrid in base assumptions

- Determine the difference in carbon emissions between scenarios and value these differences at the applicable price of carbon. This is most relevant if a carbon price is applied in the market.
- Ensure that emissions are consistent between the BAU scenario and the scenarios with network development options. Any effect of network development in reducing emissions directly (such as allowing additional wind generation to avoid curtailment) will therefore result in capital and variable cost savings.

Our modelling is based on profitability-based generation development (discussed further in Section 3.2). Given this, the former of these approaches has been applied.

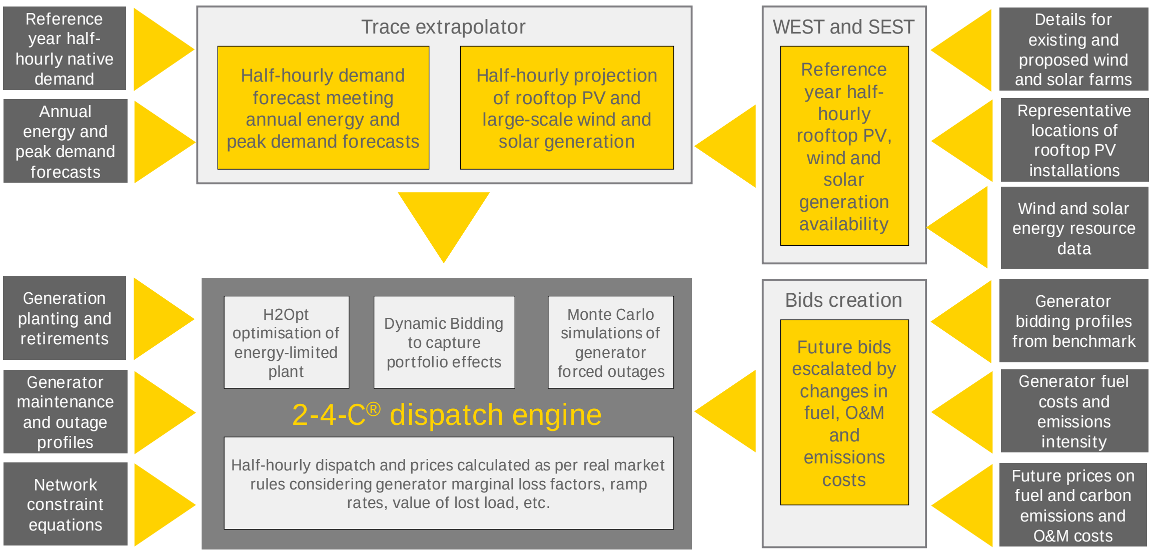
3.2 Market dispatch modelling methodology

3.2.1 Time-sequential modelling

3.2.1.1 2-4-C®

We performed time-sequential dispatch simulations of the NEM on a half-hourly basis for the period 2018–19 to 2049–50. The simulations use EY's electricity market dispatch engine 2-4-C® which emulates the dispatch engines used by power system operators. It dispatches generators (and bidding interconnectors and loads) according to their merit order, which is determined by their bids and transmission loss factors. Available generators in each half hour (those not on planned or unplanned outages) are dispatched in order from the lowest bid to the highest bid to meet half-hourly demand in each region, subject to network limitations and energy constraints. Each half hour is referred to as a trading interval (TI). Figure 1 shows a flow diagram summarising the various inputs and tools used with 2-4-C®.

Figure 1: Market dispatch and pricing with 2-4-C®



We modelled a single demand trajectory based on the 50% probability of exceedance (POE) peak demand. This was a modelling compromise driven directly by the significantly increased simulation times as a result of implementing a full nodal model for all transmission network nodes in New South Wales, South Australia and Victoria. Whilst this is not ideal, it was observed that the 10% and 50% POE scenarios showed minimal divergence in generation scarcity and price volatility, with these being driven more by variability in renewable traces than peak demand. It is also noted that in preparing the PSCR, AEMO has only modelled a 50% POE scenario, stating that a 10% POE scenario has not been considered in the PSCR due to only minor increases in constraint binding hours from the 50% POE scenario[17].

[17] Appendix B.1 Demand Assumptions – Western Victoria Renewable Integration PSCR

EY has modelled five Monte Carlo iterations of forced outages for the 50% POE demand profile with annual results presented in this Report as the average of all iterations. Further detailed modelling would incorporate modelling a 10% POE demand trace, with appropriate weightings across the scenarios for reporting purposes.

3.2.2 Generation development plan

Our modelling uses an iterative approach to determine the timings of generation investment and retirements. In addition, a number of generation retirements are fixed due to company announcements and assumptions related to end of technical life. EY has applied the same fixed retirements as those applied in the AEMO NTNDP 2016.

During the LRET, renewable generation is developed to meet the national target, with consideration of the contribution by Western Australia and other non-NEM generation, GreenPower schemes, etc. The choice of where renewable generation is developed in the NEM is informed by consideration of regional resource quality and the wholesale revenue forecasts for renewable generation in each region.

The VRET has been explicitly modelled in Victoria with 'forced planting' to achieve an initial target of 25% of energy production met by renewables by 2020 increasing to 40% by 2025 in the BAU scenario, whilst taking into account the impact of network congestion on generator curtailment. The majority of generation installed in Western Victoria has been assumed to connect to the 220 kV network, consistent with the connection enquiries received by AEMO to date. Despite some connection enquiries received specifying a 66 KV connection, this has not been modelled for the purpose of this study, which focuses on 220 kV and 500 kV network augmentation.

In addition to the committed and announced retirement of thermal assets, additional retirement and the addition of new entrant generation other than those planted to meet the VRET is informed by wholesale market profitability outcomes and market signals. Generators are retired when they are consistently unable to recover their fuel and operations and maintenance (O&M) costs. Similarly, new entrant generators are installed if they are able to recover their capital, fuel and O&M costs.

Notwithstanding the above, it is recognised that investment decisions are not purely based on market forecasts. In reality, market signals may not always be timely and clear enough for the market to respond in an orderly, controlled and efficient manner. Regulatory uncertainty and manual policy intervention introduces a complicating factor. As such, the market benefit modelling presented here may understate the benefits that might be realised from the network development scenarios.

Additionally, this scope of work has not considered the inclusion of Snowy 2.0 in the generation development plan. Further work would be needed to assess the potential for additional benefits as a result of its inclusion in the generation development plan.

3.2.3 Generator connection costs

Each generator in Victoria is assumed to have an indicative relative transmission connection cost component based on information published by AEMO[18]. Connection costs are typically driven by the connection voltage, type of connection (i.e. single circuit or double circuit) and distance of the site from the connection point. Generator connections in Western Victoria are centred on the 220 kV and 500 kV networks. EY has differentiated between the cost to connect a generator at the 220 kV and the 500 kV, which contributes to the total system capital costs. Based on information published by AEMO[18], a connection cost multiplier of x2.3 was applied to generators connecting at the 500 kV compared to connection at 220 kV, representing the additional cost of 500 kV plant assets

[18] https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/Victoria-transmission-connections---process-overview/-/media/50EFAD2F3CFC4B30884864A8C528B627.ashx

compared with similar 220 kV plant. Connection costs are then factored into the whole of system cost calculation described in Section 3.4.1.

3.2.4 South Australian Energy Plan

In response to widely reported energy security issues in South Australia, the South Australian Energy Plan was released which included a request for expressions of interest for the installation of a 250 MW OCGT and 100 MW of battery storage. These developments have been modelled in this assessment with the required plant installed by 1 July 2021. Battery storage is assumed to be connected July 2018[19].

A further requirement in South Australia is that at least two synchronous units must be spinning at all times. This requirement is linked with the ROCOF constraint as the operation of synchronous units allows more Heywood capacity to be used. This has been implemented through bidding, whereby some units bid at the market floor price (-$1,000/MWh) such that at least two units in SA are operational at all times. The ROCOF constraint is also explicitly modelled.

3.3 Proposed network development scenarios

The network augmentation options modelled are summarised in Table 2. Further information is provided in Appendix B. These options were provided to EY by TransGrid for this Report. Modelling extends from 2018-19 to 2049-50. The timing for each network option is specified in Table 2.

Table 2: Network development scenarios modelled

<table>
<tr><th>Scenario Reference</th><th>Strategic Theme</th><th>Brief Description</th></tr>
<tr><td>Scenario 1</td><td>Business-as-usual</td><td>No network augmentation
Do Nothing</td></tr>
<tr><td>Scenario 2</td><td rowspan="4">Additional interconnection between New South Wales and Victoria</td><td>Victoria to New South Wales 330 kV Single Circuit Reinforcement</td></tr>
<tr><td>Scenario 3</td><td>Victoria to New South Wales 330 kV Double Circuit Reinforcement</td></tr>
<tr><td>Scenario 5</td><td>Victoria to New South Wales 330 kV Double Circuit Reinforcement with Western Victoria 500 kV and 220 kV reinforcement</td></tr>
<tr><td>Scenario 6</td><td>Snowy to South Morang 330 kV Reinforcement</td></tr>
<tr><td>Scenario 4</td><td rowspan="2">Intra-regional Victoria network reinforcement</td><td>Western Victoria 500 kV, 220 kV Reinforcement</td></tr>
<tr><td>Scenario 9</td><td>Subset of Scenario 4</td></tr>
<tr><td>Scenario 7</td><td rowspan="2">Victoria network reinforcement with interconnection to South Australia and New South Wales</td><td>Scenario 5 plus NSW-SA Interconnector</td></tr>
<tr><td>Scenario 8</td><td>Scenario 5 plus VIC-SA Interconnector</td></tr>
</table>

3.4 Inter-regional loss factors

AEMO calculate inter-regional loss factor equations that are applied in the dispatch process. The methodology for this calculation is described in AEMO's *Methodology for Calculating Forward-Looking Transmission Loss Factors*[20]. This methodology is problematic for parallel interconnectors that share the same network elements (as power flow on one interconnector becomes an important

[19] http://ourenergyplan.sa.gov.au/assets/our-energy-plan-sa-web.pdf

[20] Available at: https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries

variable for losses on the other). AEMO's methodology has not been implemented in the modelling performed here.

Instead losses are implemented using a full nodal model that calculates losses on every branch element as part of the dispatch process. Any benefits resulting from reduced losses are therefore incorporated into the variable cost differences between scenarios.

In addition to modelling the transmission system on a nodal basis that is fully equivalent to the regional basis implemented for the NEM at present, EY has included the stability constraints that apply between regions, based on information provided by TransGrid as to the increased inter-regional capacity provided by the expanded inter-regional interconnectors.

3.5 Comparison with network options in AEMO's PSCR

A number of TransGrid's proposed network augmentations considered in this Report are equivalent to those discussed in AEMO's PSCR. The PSCR discusses credible network augmentation options that could be implemented to address the network congestion issues. The options discussed are centred around intra-regional network reinforcement in Victoria involving the installation of additional network capacity on the 220 kV, 275 kV, 330 kV or the 500 kV networks. The PSCR states that the recommended option will likely be a combination of several options listed[21]. This broadly aligns with the options proposed by TransGrid which fall under the "Intra-regional Victorian network reinforcement" theme. TransGrid also consider the benefits of inter-regional network connection coupled with network reinforcement in Victoria, which AEMO may also consider in the later stages of the RIT-T consultation process.

3.6 Cost-benefit assessment

3.6.1 Cost-benefit outputs from market modelling

The key objective of this analysis is to determine the reduction in total system cost that occurs as a result of the different network scenarios proposed relative to a BAU scenario where there is no new network augmentation.

In each scenario we compute the following market cost and benefit components[22]. The sum of the following components is referred to as the total system cost, which includes:

- Capital costs of new generation capacity installed in each scenario (taking into account whether that generation may be installed on the 220 kV or 500 kV for the Western Victorian region).
- Total fixed O&M costs of all generation capacity.
- Total variable costs (fuel costs + variable O&M costs) but not including carbon costs.
- Reliability cost comprising cost of Unserved Energy ("USE") and Demand Side Participation ("DSP").
- Carbon costs (representing the cost of emissions), which are included as a separate line item.

From the half-hourly time-sequential modelling we computed each component of annual cost in each scenario. We then computed the difference between each network augmentation option and the BAU scenario – this is the annual market benefits. The discounted NPVs of annual market benefits are referred to as market benefits.

The annual market benefits include many of the categories of market benefits specified in the RIT-T. This includes all generator specific costs (fuel, direct costs such as capital, O&M) and the cost of voluntary and involuntary load shedding (valued at DSP price as bid and the Value of Customer

[21] Western Victoria Renewable Inetegration – Project Specification Consultation Report – April 2017; Pg 22
[22] Based on the principles outlined in the AER's "Regulatory investment test for transmission application guidelines"

Reliability ("VCR") respectively). Carbon price is included in the calculation of market benefits as a specific line item.

The VCR used is based on AEMO's 2016 review which provides a NEM wide value of $25,950 per MWh[23] based on the residential value. This represents a simplification of the differing customer base as it does not specifically consider the different VCR values across regions, as well as differing VCR values across customer segments (i.e. residential, business, large customers). Consideration of business and large customer VCR values would result in additional market benefit, as residential VCR values are lower than other customer segments.

Market benefits also capture some of the impact on transmission losses to the extent that network losses affect the generation that is needed to be dispatched in each trading interval. Therefore, the modelling accounts for the impact of reduced losses as a result of parallel network reinforcement and reduced network impedances by reductions in the "gross" demand required in each period. The impact of higher losses will therefore be evident through subsequent increases in variable costs required to meet higher demand and vice versa.

Other market benefits excluded from this assessment include changes in ancillary service costs, competition benefits and timing of deferred transmission network investment as a result of these network development scenarios. Also, consideration of market benefits associated with high impact low probability events such as "N-2", multiple interconnector outages and common mode terminal station failures have not been factored into results at this stage. This is discussed further in Section 5.

3.6.2 Calculating the NPV of market benefits

Each component of market benefits is computed annually for each year of the study period. In this Report, we summarise these revenue and cost streams using a single value computed as the NPV of each stream, discounted to 1 July 2018 at a specified discount rate.

We present outcomes using a 7.5% real pre-tax discount rate. This value has been applied to all network option scenarios. For consideration of whether a network augmentation option results in market benefits that exceed its cost, a more detailed analysis of discount rate may be required. The 7.5% discount rate is broadly consistent[24] with the rates applied for this type of investment. There has not been a detailed consideration of this value and use of this value in this Report does not indicate a suggestion from EY that this is the most appropriate value to be used in a RIT-T.

3.6.3 Network augmentation costs

EY has not been provided with the capital cost estimates for each of the proposed network augmentations. The differences in the capital costs of each network augmentation option will need to be considered when evaluating the relative net benefits of each option. Given that market benefits are provided on a discounted basis, the costs of the augmentation will need to be discounted on the same basis.

[23] Value of customer reliability. We have applied a value of $25,950/MWh. Sourced from: http://www.aemo.com.au/-/media/Files/PDF/VCR-Application-Guide--Final-report.pdf

[24] As agreed with TransGrid. Note that AEMO's NTNDP 2016 uses a discount rate of 7.0%.

4. Outcomes

4.1 Additional Interconnection Between NSW and VIC

4.1.1 Market benefits

Table 3 shows the market benefits associated with the network development scenarios centred on additional interconnection between New South Wales and Victoria. Four options were provided by TransGrid, summarised below.

- Scenario 2 – Victoria to New South Wales 330 kV Single Circuit Reinforcement
- Scenario 3 – Victoria to New South Wales 330 kV Double Circuit Reinforcement
- Scenario 5 – Victoria to New South Wales 330 kV Double Circuit Reinforcement, with Western Victoria 500 kV and 220 kV reinforcement
- Scenario 6 – Snowy Hydro to South Morang 330 kV Reinforcement

Table 3: Market benefits additional interconnection between NSW and VIC

	Scenario 2	Scenario 3	Scenario 5	Scenario 6
NPV of reliability benefits ($m)	0	1	0	1
NPV of variable cost ($m)	3	59	48	268
NPV of fixed O&M cost ($m)	41	46	122	0
NPV of capital cost ($m)	147	164	423	0
NPV of carbon ($m)	2	12	24	13
Total NPV including carbon ($m)	193	282	617	282
Total NPV excluding carbon ($m)	191	270	593	269

The table above outlines the components of market benefits relative to the BAU scenario. It should be noted that consideration of a single category of market benefit can be deceptive given the categories are highly related. For example, additional investment in renewable generation will tend to increase capital costs but reduce variable costs. Similarly, the impact of additional network augmentation may relieve network congestion and increase reliability (i.e. through lower observed levels of voluntary and involuntary load shedding) or through deferral of capital cost, or both. However, for the studies conducted for this report, the values of unserved energy are extremely low, and make no material difference to the outcomes, due to the significant additional capacity and energy delivered by the RET and VRET schemes.

The key outcomes are described below:

- The main driver for market benefits for scenarios 2, 3 and 5 were capital cost deferrals as a result of less renewable plant required to meet the VRET.
- Scenario 2 and Scenario 3 did not include any upgrades to the Western Victorian 220 kV network and showed lower market benefits than Scenario 5. The intention of these reinforcements is to provide an export point from the 220 kV network from Western Victoria into the New South Wales region through a new Kerang 330/220 kV transformer. However, the power flows onto the new 330 kV circuit were still limited by 220 kV transmission network supplying the transformer. The lack of 220 kV network augmentation resulted in 220 kV congestion still being present. It is noted that these scenarios may still provide net market benefits depending on the capital cost of the network development, and may facilitate a staged development approach which leads to a more complete network solution as modelled in Scenarios 5, 7 and 8.

- Market benefits associated with reinforcing the 330 kV network between Snowy Hydro and South Morang (Scenario 6) were driven by providing New South Wales with strong access to cheaper Victorian generation as well as reductions in Victorian OCGT generation. This resulted in large fuel cost savings as a result of cheaper Victorian generation displacing New South Wales generation and reduced gas usage.
- Reinforcing the 330 kV network between Snowy Hydro and South Morang (Scenario 6) did not alter the generation planting in Victoria as no network augmentation was performed on the 220 kV network resulting in congestion still remaining in that region. As such, capital cost savings were not identified.
- Additional network capacity between New South Wales and Victoria results in second order fuel cost savings which were associated with increased brown coal and renewable generation in Victoria displacing more expensive New South Wales coal generation. As a result, the total variable cost of the system is reduced.
- It should be noted that Snowy 2.0 was not included in the generation development plan under Scenario 6. Additional work to determine the impact of Snowy 2.0 on the potential for market benefits may be part of further detailed investigations.

4.2 Intra-regional Victorian network reinforcement

4.2.1 Market benefits

Table 4 shows the market benefits associated with the network development scenarios centred on intra-regional network reinforcement in Victoria. Two options were provided by TransGrid, based on network development options discussed in AEMO's PSCR. The two network development scenarios consider full network augmentation of the 220 kV and 500 kV networks. Scenario 9 represents a subset of augmentations in Scenario 4. The market benefits are summarised below.

- Scenario 4 – Western Victoria 500 kV, 220 kV Reinforcement
- Scenario 9 – A subset of the Western Victoria 500 kV, 220 kV Reinforcement

Table 4: Market benefits associated with intra-regional Victorian network reinforcement

	Scenario 4	Scenario 9
NPV of reliability benefits ($m)	0	0
NPV of variable cost ($m)	28	71
NPV of fixed O&M cost ($m)	121	94
NPV of capital cost ($m)	414	322
NPV of carbon ($m)	39	52
Total NPV including carbon ($m)	602	539
Total NPV excluding carbon ($m)	563	487

The key outcomes are described below:

- The main driver for market benefits for Scenario 4 and Scenario 9 are capital cost deferrals as a result of less renewable plant to meet the VRET. The benefits associated with relieving intra-regional 220 kV network congestion allowed improved export from the Western Victorian generation centre to load centres in Victoria and New South Wales. Achieved capacity factors from renewable plant in the Western Victorian region improved by more than 10% in some instances.
- The analysis indicates network augmentations similar to those provided in AEMO's PSCR may provide market benefits in the order of $500-$600 M. Whilst AEMO's modelling is centred on variable cost savings, EY's modelling shows there is potential for benefits associated with reductions in capital costs as well. This may be compared with AEMO's PSCR which states the

potential for market benefits to be in the range of $300-$500 M driven solely from a reduction in variable generation costs. These are broadly aligned given AEMO's modelling does not yet consider whole of system costs.

- Second order benefits were found as a result of less generation capacity being installed in the region. This resulted in lower fixed operational and maintenance costs required to service the generation fleet across the study period.
- Carbon benefits were also identified, resulting from increased renewable energy production compared to the BAU scenario, as a result of less network congestion and therefore better achieved capacity factors for renewables in the region.

4.3 Intra-regional Victorian network reinforcement with interconnection

4.3.1 Market benefits

Table 5 shows the market benefits associated with the network development scenarios centred on network reinforcement in Victoria (both intra-regional and with additional interconnection to New South Wales), coupled with additional interconnection to South Australia. Two options were provided by TransGrid, one involving additional interconnection between New South Wales and South Australia, and the other involving interconnection between Victoria and South Australia.

- Scenario 7 – Western Victoria 500 kV, 220 kV Reinforcement with the NSW-SA Interconnector
- Scenario 8 – Western Victoria 500 kV, 220 kV Reinforcement with the VIC-SA Interconnector

Table 5: Market benefits associated with Inter- and Intra-regional Network Reinforcement

	Scenario 7	Scenario 8
NPV of reliability benefits ($m)	2	2
NPV of variable cost ($m)	-21	9
NPV of fixed O&M cost ($m)	195	181
NPV of capital cost ($m)	752	713
NPV of carbon ($m)	-5	4
Total NPV including carbon ($m)	923	909
Total NPV excluding carbon ($m)	928	905

The key outcomes are described below:

- The options that involved additional interconnection from Victoria to South Australia and New South Wales, with intra-regional network reinforcement in Victoria, produced the highest market benefits. These showed potential market benefits in excess of $900 M, driven primarily by reductions in capital and O&M costs.
- The additional inter-regional power flows and the ability to share cheap generation across regions resulted in less generation capacity being built across the NEM.
- Whilst EY has not been provided with capital cost estimates, it is likely that network development scenarios under these themes will be more expensive from a capital cost perspective.
- Second order benefits were found as a result of less generation capacity being installed in the region. This resulted in lower fixed operational and maintenance costs required to service the generation fleet across the study period. This conversely had an impact on carbon benefits, as less installed renewable capacity resulted in lower carbon benefits in comparison to other scenarios.

5. Discussion of market benefits and costs

There are several sources of additional benefits that may result from the network augmentation that are not captured in the market benefits presented in this Report.

5.1 Energy security in South Australia due to system separation

Our modelling incorporates some elements of South Australian energy security, however a proportion of the potential benefits that could have been realised are likely to be addressed by the South Australian Energy Plan pending commissioning and required funding approvals. It is assumed in this modelling that this plan is constructed within the required time frame. As such, our modelling does not incorporate the potential benefits that may result from an event such as a system blackout occurring in the years prior.

Since the September blackout AEMO have taken measures to reduce the likelihood that system separation will lead to a blackout. This includes the introduction of regulations to limit ROCOF to 3 Hz/s as well as the potential installation of special protection schemes to trip load in the event of system security risks.

Additionally, AEMO have since requested wind farms to update voltage ride through settings, and are likely to exhibit a renewed focus on generator connection agreements, performance standards and generator compliance programs.

Since these measures are intended to greatly reduce the risk of blackouts, the potential market benefits are offset by arguably significantly lower probabilities of the system separation events occurring. We accept that there will be additional benefits from interconnection above our estimates, which do not take into account blackouts, but do allow for multiple generation contingencies.

5.2 Frequency Control Ancillary Services (FCAS)

The cost of ancillary services is skewed to SA. This is due to the implementation of a 35 MW local regulation FCAS requirement at times of system separation risk, to assist in managing the frequency in the event of a contingency. The cost of regulation FCAS in SA was 67% of the total cost of regulation FCAS in the NEM in 2016, primarily due to the risk of system separation.

The risk of system separation has been unusually high in recent years. This is due to scheduled temporary line outages during the implementation of the Heywood upgrade which has resulted in an increased incidence of a Heywood outage being classified as a credible contingency. However, even when this upgrade is complete, the risk of system separation is likely to continue to be material without additional interconnection. When system separation is a credible contingency, regulation FCAS prices would likely be high.

The cost of regulation FCAS in SA will reduce in the event of interconnector augmentation to a level proportional to the size of SA relative to the remainder of the NEM. This value has not been estimated. The *South Australian Energy Transformation: RIT-T Market Modelling Approach and Assumptions Report* by ElectraNet has further discussion of this issue[25].

5.3 Other modelling limitations

Our modelling does not consider the impact of the additional interconnection and network reinforcement on transmission development across the NEM. The cost of the interconnector assumed in the modelling considers only the direct costs of additional interconnection.

[25] Available here: https://www.electranet.com.au/projects/south-australian-energy-transformation/

The modelling has not attempted to quantify competition benefits. Given the long timeframe of the modelling, the competitive dynamics in the wholesale market are highly uncertain. Furthermore, a number of existing coal assets are retired in the modelling such that the existing generation portfolios would be very different during the study period. Therefore any assessment of the impact of additional interconnection on competition would be highly speculative and heavily dependent on assumptions such as contracting positions and the concentration of ownership in new generation assets. In addition, the development of the interconnector reduces investment in new thermal capacity, which could itself affect competitive dynamics.

The modelling does not consider benefits associated with high impact low probability events ("HILP") such as N-2, multiple interconnector outages or common node failures at terminal stations. These benefits may result in additional market benefits which are not captured here. These may be modelled in the Project Assessment Draft Report phase of the RIT-T, with suitable assigned probabilities and market scenarios that capture these events.

Appendix A List of acronyms

Acronym	Expanded name
AEMO	Australian Energy Market Operator
BAU	Business as Usual
DSP	Demand Side Participation
FCAS	Frequency control ancillary services
LCOE	Levelised Cost of Energy
LRET	Large-scale Renewable Energy Target
LRMC	Long-run marginal cost
NEM	National Electricity Market
NPV	Net present value
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
O&M	Operations and maintenance
POE	Probability of exceedance
PSCR	Project Specification Consultation Report
RIS	Required in service
ROCOF	Rate of change of frequency
SA	South Australia
SPS	Special Protection Scheme
SRMC	Short-run marginal cost
USE	Unserved Energy

Appendix B Network augmentation options

Scenario	RIS	Network Augmentations
1	N/A	None
2	2021	Darlington Point (NSW) to Kerang (VIC) (330kV)
		400 MVA 330/220 kV transformer at Kerang (330kV)
3	2021	Double circuit Darlington Point (NSW) to Kerang (VIC) (330kV)
		400 MVA 330/220 kV transformer at Kerang (330kV)
		Darlington Point to Wagga (330kV) additional circuit
4	2021	Ballarat to Sydenham (500kV)
		Ballarat to Moorabool (500kV)
		2 x 220/500 kV 600MVA transformers at Ballarat
		Red cliffs to Wemen (220kV) additional circuit
		Red cliffs to Horsham (220kV) additional circuit
		Wemen to Kerang (220kV) additional circuit
		Kerang to Bendigo (220kV) additional circuit
		Bendigo to Ballarat (220kV) additional circuit
		Bendigo to Fosterville (220kV) additional circuit
		Fosterville to Shepparton (220kV) additional circuit
		Horsham to Ararat (220kV) additional circuit
		Double circuit Ararat to Waubra (220kV) additional circuits
		Double circuit Waubra to Ballarat (220kV) additional circuits
		Terang to Moorabool (220kV) additional circuit
		Ballarat to Terang (220kV) additional circuit
5	2023	Darlington Point to Kerang (330kV) additional circuit
		Darlington Point to Wagga (330kV) additional circuit
		Double circuit Kerang to Mid-point (330kV)
		Double circuit Mid-point to Ballarat (330kV)
		2 x 330/500 kV 500MVA transformers at Ballarat
		2 x 220/500 kV 600MVA transformers at Ballarat
		Ballarat to Sydenham (500kV)
		Ballarat to Moorabool (500kV)
		Double circuit Ararat to Ballarat (via Waubra) (220kV) additional circuits [Ararat to Waubra Component]
		Double circuit Ararat to Ballarat (via Waubra) (220kV) additional circuits [Waubra to Ballarat Component]
6	2023	Double circuit Lower Tumut (NSW) to Murray (VIC) (330kV) additional circuits
		Double circuit Murray to Dederang (330kV) additional circuits
		Double circuit Dederang to South Morang additional circuits

Scenario	RIS	Network Augmentations
7	2023	Everything included in option 5
		Double circuit Buronga (NSW) to Robertstown (SA) (275kV)
		Buronga to Darlington point (275kV)
		Darlington point to Wagga (330kV) Additional circuit
		Phase shifting transformers at Buronga
		275/330kV transformer at Darlington point
		220/275kV transformer at Buronga
8	2023	Everything included in option 5
		Double circuit Horsham(Vic) to Tungkillo(SA) (275kV)
		2 x phase shifting transformers at Horsham
		2 x 275/220 kV transformers at Horsham
		Horsham – Ararat (220kV) additional circuit
		Double circuit midpoint 330 to midpoint 220
		Double circuit mid220 to Horsham (220kV)
9	2021	Ballarat to Sydenham (500kV)
		Ballarat to Moorabool (500kV)
		2 x 220/500 kV 600MVA transformers at Ballarat
		Ararat to Waubra (220kV)
		Ararat to Waubra (220kV)
		Waubra to Ballarat (220kV)
		Waubra to Ballarat (220kV)

Source: TransGrid

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