FINAL REPORT

13 October 2008

# >> Potential Upgrade of Queensland/New South Wales Interconnector (QNI) – Assessment of Optimal Timing and Net Market Benefits

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# EXECUTIVE SUMMARY

This Report applies the methodology of the Australian Energy Regulator's (AER) Regulatory Test to five potential options to upgrade the transfer capacity of the Queensland-New South Wales Interconnector (QNI).

It concludes that the optimal timing for a capacity upgrade via the installation of series compensation equipment (which would deliver an increase to the stability limits by up to nominally 300-400MW) is 2015/16.

It also therefore concludes that, absent of any large changes in forecast load growth and generation developments compared with what has been assumed in this analysis, it is premature for TransGrid and Powerlink Queensland to recommend an augmentation option at this point in time.

As a network augmentation is not being recommended at this time, TransGrid and Powerlink Queensland are publishing this Final Report for the information of Registered Participants and interested parties. This report is therefore not a Final Report required under the National Electricity Rules when recommending a network augmentation.

Background

TransGrid and Powerlink Queensland (Powerlink) are the Transmission Network Service Providers (TNSPs) in New South Wales and Queensland respectively and are also the designated jurisdictional transmission network planning bodies appointed by their respective State Governments.

The two organisations planned and constructed the QNI, which commenced commercial operation in February 2001. In the context of the National Electricity Market (NEM), QNI was a very long interconnection (around 600km) and required extensive post-commissioning testing to ensure that it maintained stability over a range of operating conditions. Consideration of power system stability is the main factor that limits the power flow across QNI. That is, the capacity to maintain transient and oscillatory stability and ensuring appropriate voltage levels following a critical contingency, are pivotal to determining the power flow limits.

Following this testing, the transfer capacity is now determined to be up to 700MW north and up to 1,078MW south. (This compares with the original design capacity of up to 500MW north and up to 1,000MW south).

The transfer capacity of QNI has been and continues to be well utilised, with frequent periods of operation at its maximum transfer capability, particularly prior to the recent drought period (2007) which led to restricted output from some generators in southern Queensland. QNI has been widely recognised as a valuable infrastructure investment, with large annual savings in ancillary services costs as well as sharing capacity reserves, compared with the pre-interconnection costs.

TransGrid and Powerlink are cognisant of the fact that the observed levels of constrained operation of QNI would result in deviations from least cost dispatch of generation and may impact on the operation of some market participants. For this reason, TransGrid and Powerlink have conducted joint planning investigations in order to develop (and share with the market) a clear understanding of the technical and economic issues that need to be considered in order to alleviate these constraints, as well as the optimal timing and nature of any upgrade. As QNI is a regulated interconnector, any proposal to upgrade its capacity will need to undergo a process that conforms to the rules governing inter-network augmentation.

The National Electricity Rules (Rules), specifically clause 5.6.6, requires transmission businesses to carry out a Regulatory Test analysis and market consultation before they establish new large network assets. The joint planning investigations on the potential upgrade of QNI have therefore been based on the Regulatory Test. The test is a form of cost-benefits analysis for assessing alternative network and non-network options, based on whether the augmentation is required to meet minimum network performance requirements, or the augmentation can be justified in terms of the expected net market benefits. The market benefit limb of the Regulatory Test is applicable to this assessment, as the need for upgrading QNI is not driven by a requirement to meet mandatory network standards.

Summary of Analysis

TransGrid and Powerlink have identified five technically feasible options, each delivering different increments in QNI transfer capability. These options are described within Table A.

**Table A - QNI Upgrade Options**

| Option | Description | Estimated Capital Cost |
|---|---|---|
| Option 1 | Series compensation<br>This option involves the installation of series compensation across the Bulli Creek to Dumaresq and Dumaresq to Armidale 330kV circuits together with minor supporting works. | \$120M |
| Option 2 | Northern NSW SVC<br>This option involves the installation of Static VAr Compensator (SVC) at Armidale 330kV substation. | \$35M |
| Option 3 | System Protection Scheme<br>This option involves the installation of a braking resistor at Loy Yang substation in Victoria and implementation of high speed System Protection Schemes (SPS) to allow higher transfers across the existing QNI infrastructure. | \$35M |
| Option 4 | High Voltage Direct Current Back to Back System<br>This option involves the installation of a 1,500MW High Voltage Direct Current (HVDC) back to back asynchronous link located in the interconnected network between Bulli Creek and Dumaresq substations. | \$470M |
| Option 5 | Second High Voltage Alternating Current (HVAC) Connector<br>This option involves the construction of an additional 330kV double circuit transmission line and intermediate switching stations between Bulli Creek and Bayswater substations. | \$900M |

The Regulatory Test requires that the costs and benefits of options be assessed under a range of reasonable market development scenarios. The scenarios considered within this report are summarised within Table B.

**Table B - Market Development Scenarios**

| Scenario | Description |
|---|---|
| Scenario A | Medium economic growth using "realistic" generator bidding behaviour |
| Scenario B | High economic growth using "realistic" generator bidding behaviour |
| Scenario C | Low economic growth using "realistic" generator bidding behaviour |
| Scenario D | Medium economic growth using short run marginal cost (SRMC) generator bidding behaviour |

In applying the Regulatory Test, TransGrid and Powerlink have treated all scenarios as having equal weighting. However it is noted from Table B that Scenario A and D are both based on medium economic growth. While this has the practical effect of assigning a higher weighting to the medium economic growth scenario and lower weightings to each of the low and high economic growth scenarios, based on present knowledge of the NEM, medium economic growth is the most likely growth outcome to occur. TransGrid and Powerlink regard this as a reasonable approach.

The market benefits for each option were determined through the use of forward looking market simulations which are designed to model the operation of the NEM over a 13-year time frame. This simulation period allows for a ten year analysis of market costs and benefits following a notional three year lead time for project implementation and commissioning.

The optimal timing for each option was determined by calculating the Net Present Value (NPV) of the market benefits for a range of possible commissioning dates and from this, identifying the commissioning date that gives the highest market benefit NPV. The optimal timing identified for each option is shown in Table C.

**Table C - Optimal Timing for QNI Upgrade Options**

| Options | Scenarios | | | |
|---|---|---|---|---|
| | A | B | C | D |
| 1 - Series Compensation | 2015/16 | 2009/10 | 2020/21 | 2013/14 |
| 2 - Northern NSW SVC | 2016/17 | 2013/14 | ( - )[1] | 2014/15 |
| 3 - System Protection Scheme | 2018/19 | n/a[2] | n/a | n/a |
| 4 - HVDC Back to Back System | ( - )[1] | n/a | n/a | n/a |
| 5 - Second HVAC Connector | ( - )[1] | n/a | n/a | n/a |

[1] No optimal timing could be established as annual market benefits never exceeded annualised costs of the augmentation.
[2] n/a in Table C represents where market simulations were not carried out.

It is noted that detailed market analyses (and therefore optimal timing determinations) were not undertaken for options which were clearly inferior in terms of net market benefits (i.e. which had no chance of satisfying a Regulatory Test). This decision was taken in the interests of cost efficiency of conducting the market analysis study.
It can be seen that for the most likely (medium growth) scenarios, the optimal timing for Option 1 - Series Compensation is 2015/16 (realistic generator bidding) or 2013/14 (SRMC bidding). Unsurprisingly, the high load growth Scenario B results in an earlier optimal timing of 2009/10 whereas the low growth Scenario C results in a later optimal timing of 2020/21.

The optimal timing for Option 2 - Northern NSW SVC is about one year later than for Option 1 - Series Compensation in the medium growth scenarios.

The Regulatory Test requires that the preferred option must be shown to maximise the expected NPV of the market benefits (i.e. present value of market benefit less the present value of costs) compared with a number of alternative options and timings in the majority (but not necessarily all) of the scenarios studied.

The economic assessment of each upgrade option carried out was based on a 30-year period from 2007/08 to 2037/38. As the market simulation results used in the economic assessment were based on a 13-year modelling period, the market benefits for the balance of the 30-year analysis period were assumed to continue at the same rate as the average of the last three years of the market simulation.

The NPV of market benefits for each option are summarised in Table D. The economic assessment shows that the NPV of market benefits for options 3, 4 and 5 are marginal to negative under Scenario A - medium economic growth using "realistic" generator bidding behaviour. Consequently, further market simulations were not carried out for these options under the other scenarios.

**Table D – Net Present Value (to 2037/38) of Market Benefits[3]**

| Options | Scenarios | | | |
|---|---|---|---|---|
| | A NPV ($M) | B NPV ($M) | C NPV ($M) | D NPV ($M) |
| 1 - Series Compensation | $35 | $288 | - $35 | $270 |
| 2 - Northern NSW SVC | $102 | $174 | - $32 | $196 |
| 3 - System Protection Scheme | $5 | n/a[4] | n/a | n/a |
| 4 - HVDC Back to Back System | - $206 | n/a | n/a | n/a |
| 5 - Second HVAC Connector | - $276 | n/a | n/a | n/a |

[3] The NPV values are rounded to the nearest million dollars.
[4] n/a in Table D represents where market simulations were not carried out.

The results in Table D above indicate that Option 1 - Series Compensation has the highest net present value in two scenarios (B and D), whereas Option 2 - Northern NSW SVC has the highest net present value in one scenario (A). Under Scenario C, the present value of costs for Options 1 and 2 exceed the present value of benefits and consequently the options do not return a positive net market benefit. As Option 1 maximises the expected NPV of the net market benefits in the majority of scenarios studied, it would therefore "win" a Regulatory Test.

The optimum timing for Option 1 - Series Compensation under Scenario A (medium economic growth and realistic bidding behaviour) is 2015/16, whereas it is a year later (2016/17) for Option 2 - Northern NSW SVC.

Whilst TransGrid and Powerlink are inclined to regard the "realistic" generator bidding (Scenario A) as more plausible than SRMC bidding (Scenario D), it is noted that the latter produces optimal timings which are two years earlier than Scenario A.

TransGrid and Powerlink note that this analysis does not take account of any impacts of the Commonwealth Government's proposed emissions trading scheme. Such a scheme can be expected to result in, over time, changes to generator bidding behaviour and new generation investment that are likely to affect the market simulations. These effects are quite uncertain at this point in time, given that the formulation of an emissions trading regime is a body of work in progress.

It is also noted that since the publication of the Interim Report, TransGrid and Powerlink have published revised load forecasts in their respective 2008 *Annual Planning Reports* (APRs). The market benefits modelling used in this Final Report has not been updated for the revised load forecasts. The impact of the revised load forecasts is not considered material to the conclusions of this report.

Evaluation and Conclusions

Based on the optimum timing for Option 1 of 2015/16 under Scenario A and 2013/14 under Scenario D and the later optimal timing for Option 2, TransGrid and Powerlink consider that it is premature to recommend an augmentation option at this time. Whilst the analysis undertaken is sufficient to progress an Application Notice required under the Rules, TransGrid and Powerlink are not recommending that a network augmentation be implemented.

TransGrid and Powerlink published an Interim Report for Market Consultation in March 2008 inviting submissions from Registered Participants and interested parties on the outcomes of these detailed technical and economic studies. Three submission were received from Delta Electricity, Energy Users Association of Australia, and the Queensland Government Department of Mines and Energy.

TransGrid and Powerlink have reviewed these submissions and consider that these do not change the recommendations contained within the Interim Report published earlier this year.

However, both organisations will continue to monitor market developments which could materially impact on the timing of a potential upgrade. Triggers for conducting further analysis may include a consistent "above medium" load growth totalling 2,000MW across all regions in the NEM over several years that would indicate a high economic growth scenario is emerging, or where the optimal timing may be advanced due to the entry of as-yet uncommitted new generation scheduled for commissioning from 2012 onwards, which was not included in the market modelling. Any updates will be communicated through TransGrid's and Powerlink's *Annual Planning Reports*.

# 1. INTRODUCTION

TransGrid and Powerlink Queensland (Powerlink) are the electricity transmission network owners and Transmission Network Service Providers (TNSPs) within New South Wales and Queensland respectively. These two organisations planned and constructed the existing Queensland to New South Wales Interconnector (QNI) which commenced commercial operation in early 2001.

The transfer capacity of QNI has been well utilised. QNI was constrained in excess of 2,000 hours for the 2006 calendar year and 900 hours for the 2007 calendar year (in which the drought caused significant output reductions in generators in southern Queensland).

TransGrid and Powerlink are well aware of the importance of minimising constraints for realising competitive inter-regional trade within the National Electricity Market (NEM). For this reason, TransGrid and Powerlink have previously carried out pre-feasibility studies to examine the technical and economic feasibility of upgrading the transfer capacity of the existing interconnection.

TransGrid and Powerlink have jointly undertaken a program of detailed technical and market studies, using the Australian Energy Regulator's (AER) Regulatory Test methodology, to assess the feasibility of five potential upgrade options of QNI. The outcomes of these studies are published within this report for the information of Registered Participants and interested parties.

## 1.1 Prior Investigations

During 2003, TransGrid and Powerlink carried out pre-feasibility studies of the net market benefits of a QNI upgrade under the Australian Competition and Consumer Commission (ACCC) Regulatory Test (now referred to as Regulatory Test version 1).

The main conclusion from this study is that no major upgrade of QNI could be justified under the regulatory framework existing at the time. However, the studies indicated that a relatively small intra-regional augmentation to alleviate thermal limitations within the northern New South Wales 132kV network at modest cost could be economic. This augmentation is currently under construction by TransGrid.

The results of these studies were publicly released on 19 March 2004 through Powerlink's and TransGrid's web-sites[5].

TransGrid and Powerlink also advised the market that the economic viability of upgrading QNI would be reassessed should there be a material change to the Regulatory Test or where the emerging generation pattern is different to that assumed within the studies.

Since 2002, the Australian Competition and Consumer Commission (ACCC)[6] commenced processes to review the Regulatory Test in response to views from interested parties. In August 2004, the ACCC published a revised version of the Regulatory Test (referred to as Regulatory Test version 2) which included minor amendments and clarification of competition benefits that could be taken into account when assessing the net market benefits of a network project.

[5] *Benefits of Upgrading the Capacity of the Queensland - New South Wales Interconnector (QNI) - A Preliminary Assessment*, TransGrid and Powerlink, 19 March 2004.
[6] Now the role of the Australian Energy Regulator (AER).

On 20 May 2004, CS Energy announced its commitment to construct the Kogan Creek 750MW coal fired plant for commercial operation by late 2007. The inclusion of competition benefits within the revised Regulatory Test and the commitment of a major base load power generator within Queensland were the primary triggers for reassessment of the economic viability for the upgrade of QNI.

During 2005, TransGrid and Powerlink carried out pre-feasibility studies to assess the economic viability of a QNI upgrade under the revised Regulatory Test framework. The studies indicated that an investment of around $120M (providing an increase in QNI transfer capability of around 150-200MW) might be able to deliver sufficient market benefits to satisfy the revised AER Regulatory Test with an optimum timing of late 2009.

The results of these studies were released to the market on 7 October 2005 through Powerlink's and TransGrid's web-sites[7]. TransGrid and Powerlink also held public forums in Brisbane and Sydney respectively to convey further information regarding the studies and field queries from the market.

However, as TransGrid and Powerlink commenced the program of detailed technical and market studies which are required to underpin a formal Regulatory Test analysis, a committed generation development in the New South Wales region was announced (Tallawarra). This development was subsequently followed by other generation commitments. The following commitments have been included in the market models:

- Tallawarra Combined Cycle Gas Turbine (420MW) for operation by July 2008;
- Uranquinty Open Cycle Gas Turbine (630MW) for operation by October 2008; and
- Colongra Open Cycle Gas Turbine (660MW) for operation by October 2009.

Committed generation developments do have an impact on the Regulatory test analysis of market benefits given that the largest market benefit is often the deferral of new generation investment.

## 1.2 NEMMCO ANTS

The *Annual National Transmission Statement* (ANTS) is the outcome of the National Electricity Market Management Company's (NEMMCO) annual national transmission review. It provides an integrated overview of the current and potential future development of national transmission flow paths.

As part of undertaking the annual national transmission review, market simulations are used to quantify the net market benefits of conceptual augmentations for the upgrade of national transmission flow paths. Potential augmentation opportunities across the NEM are prioritised on the basis of net market benefits.

Within the 2007 ANTS, NEMMCO reported the net market benefits for upgrading QNI using series compensation ranged from -$5M to +$75M with the market benefits exceeding the annualised equivalent cost of the upgrade ranging from 2014/15 to 2015/16 depending on assumptions relating to the value of customer reliability (VCR).

[7] Queensland – New South Wales Interconnector (QNI) Upgrade Benefits – A Pre-Feasibility Study, TransGrid and Powerlink, 7 October 2005.

## 1.3 Purpose of Study

Following the results from the 2005 pre-feasibility studies, TransGrid and Powerlink have jointly moved forward to conduct a detailed cost-benefit analysis of upgrading QNI using the methodology of the AER's Regulatory Test.

The scope of the studies has included:

- Determining the technical and design parameters of potential upgrade options;
- Calculating the respective improvements in the secure power transfer capability for each upgrade option;
- Conducting market simulation studies to quantify potential benefits to the market under a range of development scenarios;
- Examining the relative cost and benefits of these options to the market;
- Testing the sensitivity of key input variables; and
- Identification of the optimal timing and nature of a potential upgrade option.

TransGrid and Powerlink published an Interim Report for Market Consultation to present the outcomes of the technical and economic studies as well as related regulatory issues earlier this year. Whilst the economic analysis was conducted using the methodology of AER’s Regulatory Test, the Interim Report was not an Application Notice which would be required under the Rules if TransGrid and Powerlink were recommending that a network augmentation be implemented.

TransGrid and Powerlink invited submissions from Registered Participants and interested parties to provide feedback on the analysis and conclusions contained within the Interim Report. The purpose of this Final Report is to present the outcomes of the technical and economic studies into the upgrade of QNI taking into account issues raised within submissions to the Interim Report.

# 2. REGULATORY TEST FRAMEWORK

## 2.1 Introduction

The National Electricity Rules (Rules) require network service providers to carry out an assessment for determining whether a proposed augmentation option satisfies the Regulatory Test. The Australian Energy Regulator (AER) is responsible for promulgating the Regulatory Test, which is an economic cost-benefit test for comparing network and non-network options.

TransGrid and Powerlink have based the studies of potential Queensland to New South Wales Interconnector (QNI) upgrade options on the methodology of the Regulatory Test. While an augmentation option is not recommended at this time, use of the methodology provides opportunity to develop a clear understanding of related technical, economic and regulatory issues consistent with the Regulatory Test and for Registered Participants and interested parties to respond in this context.

## 2.2 Overview of the Regulatory Test

The Regulatory Test consists of two limbs as follows:

(a) Reliability limb which is used to assess network augmentations that are necessitated principally to meet the technical requirements set out in schedule 5.1 of the Rules or applicable regulatory instruments. Under this limb, an augmentation option satisfies the test if it minimises the present value of costs compared with the alternative options in a majority of reasonable scenarios; and

(b) Market benefits limb which is used for assessing all other network augmentations. Under this limb, an augmentation option satisfies this test where it maximises the expected net economic benefits to all those who produce, consume and transport electricity in the National Electricity Market (NEM) compared with the alternative options and timings in a majority of reasonable scenarios.

As the possible options for upgrading QNI within this report are not required to meet technical reliability standards, they are being assessed under the market benefits limb of the Regulatory Test.

## 2.3 Market Benefits Limb and Criteria

The market benefits limb of the Regulatory Test is applicable to non-reliability driven augmentations to the shared network. The recommended project must be the option where the:

(i) Present value of market benefits exceed the present value of costs; and

(ii) Option maximises the net market benefits compared with alternative options and timings in a majority of reasonable scenarios.

The Regulatory Test specifies the methodology that is to be used to identify and calculate costs and benefits. The definitions of quantities used within the Regulatory Test are as follows:

- Cost is the total cost of an option to all those who produce, distribute and consume electricity in the NEM. Costs may include construction, operating and maintenance costs and the cost of complying with existing and anticipated laws and regulations; and

- Market benefit is the total benefit of an option to all those who produce, distribute and consume electricity in the NEM. Benefits may include changes in fuel consumption, voluntary and involuntary load curtailments, deferral of market entry plant, changes in transmission losses and ancillary services and competition benefits.

## 2.4 The Applicable Rules and Regulatory Test

In November 2006, the Australian Energy Market Commission (AEMC) introduced clause 5.6.5A of the Rules in relation to principles for the market benefits limb within the Regulatory Test.

In December 2007, the AER issued a final decision for the Regulatory Test Version 3.

This assessment of the upgrade of QNI had commenced prior to the revised Regulatory Test Version 3 coming into effect. Accordingly, the earlier clause 5.6.5 of the Rules and Regulatory Test Version 2 has been applied to this consultation document[8].

TransGrid and Powerlink consider that the analysis of market costs and benefits is essentially the same under both version 2 and version 3 of the Regulatory Test. Accordingly the conclusions reached from this analysis are not expected to depend on the version of the Regulatory Test that is applied.

[8] Refer to clause 11.7 of the Rules.

# 3. QNI OPERATION

## 3.1 Past Performance

The Queensland to New South Wales Interconnector (QNI) is a high voltage transmission line linking the electricity networks within the Queensland and New South Wales regions. Since QNI commenced commercial operation in February 2001, the interconnector has been widely recognised as a valuable infrastructure investment which has enabled large annual savings in ancillary services costs as well as sharing capacity reserves, compared with pre-interconnector costs. The transfer capacity of QNI is well utilised. In fact, the interconnector has been operating at the limits of its secure transfer capability for significant periods of time. This includes periods of time prior to the current drought conditions that has led to restricted output from some generators in southern Queensland during 2007 in the interests of water conservation. The cumulative duration of constrained operation across QNI for the past five calendar years is shown in Table E below.

**Table E - Historical Constraint Times Across QNI**

| QNI | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| Northerly Direction (hrs) | 103 | 33 | 23 | 34 | 389 |
| Southerly Direction (hrs) | 529 | 346 | 1084 | 2063 | 513 |
| Total Constraint Times (hrs) | 632 | 379 | 1106 | 2096 | 902 |

In the early years of QNI operation, power flow was predominantly in a northerly direction during peak demand periods. However, in recent years, QNI power flow has been predominantly in the southerly direction as shown within the QNI flow duration curve in Figure 1 below.

**Figure 1 - QNI Flow Duration Curve 2003-2007**

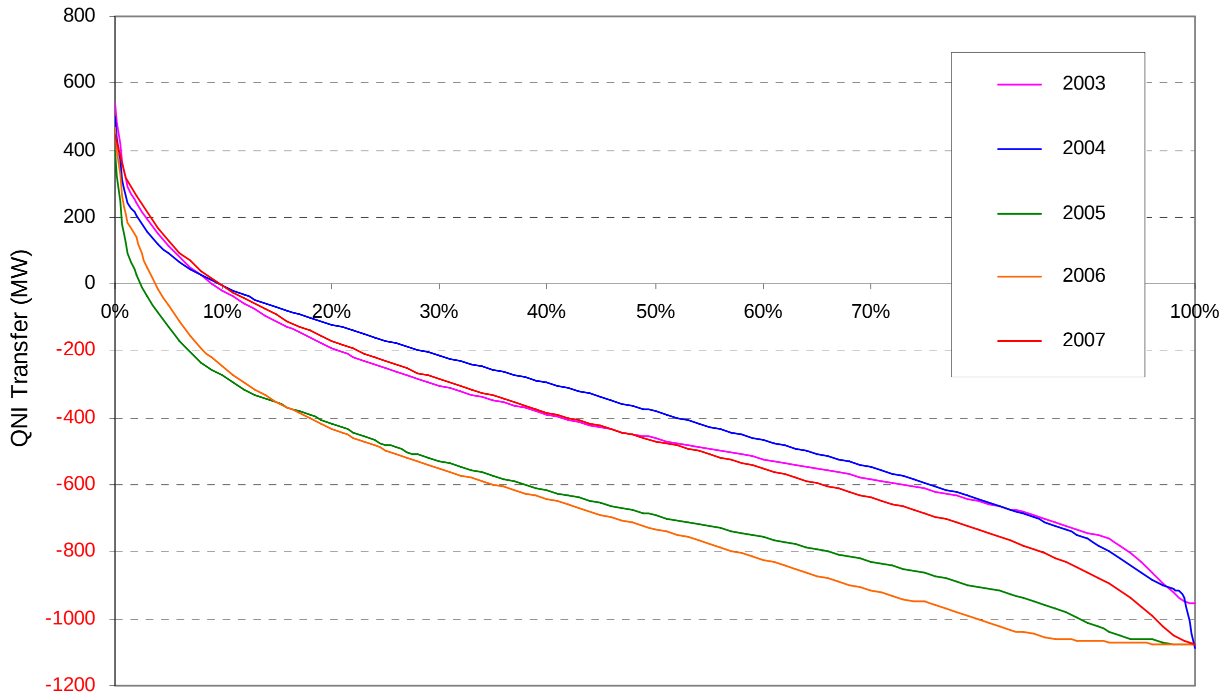
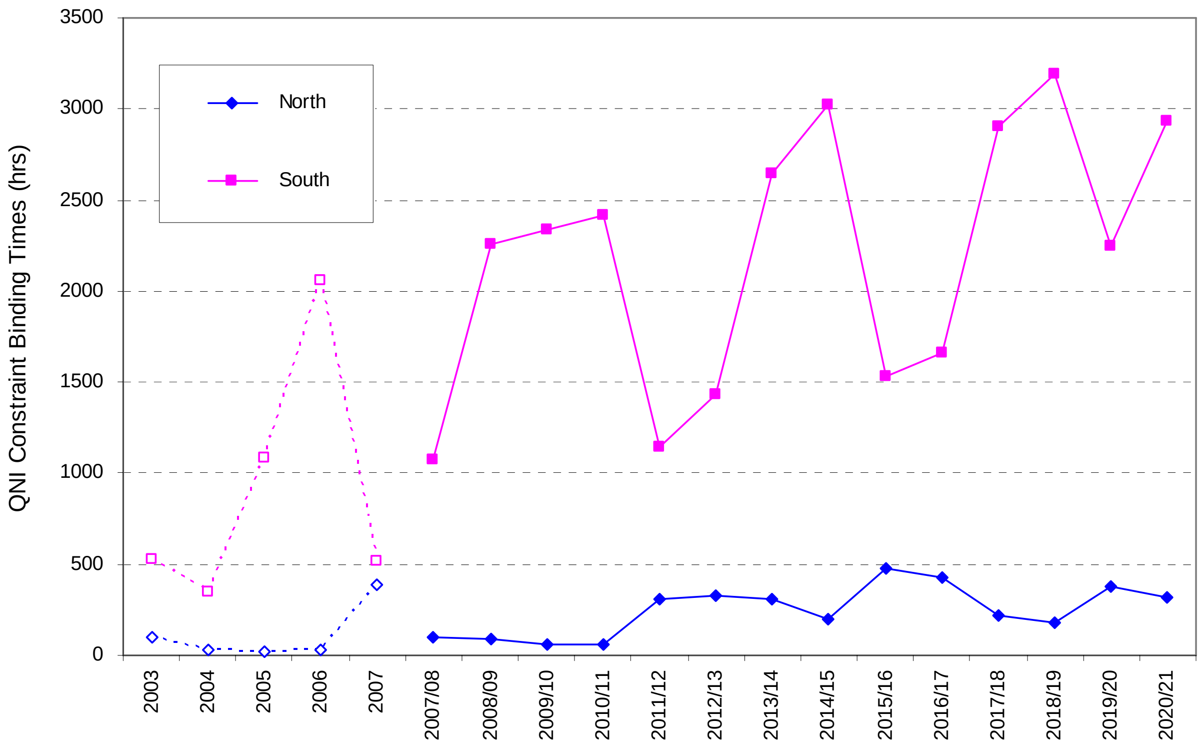


Figure 1 indicates that southerly flow across QNI occurred for around 96-97% of the time for the 2005 and 2006 calendar years and for around 90% of the time for the 2003, 2004 and 2007 calendar years.

## 3.2 Forecast Performance of QNI

The market simulations carried out as part of Regulatory Test economic assessments indicate the interconnector is forecast to be utilised at very high levels into the future. The forecast constraint times across QNI based on Scenario A (medium growth using "realistic" generator bidding behaviour) are shown within Figure 2 below.

**Figure 2 - QNI Historical and Forecast Constraint Times**




## 3.3 Transfer Capability

QNI commenced commercial operation in early 2001. To ensure that power system stability is maintained over a range of operating conditions, extensive post commissioning testing was carried out. From this testing, a transfer capacity limit equation was established which quantifies the maximum secure power transfer across QNI. The maximum power transfer may be set by transient / dynamic stability, voltage stability, or thermal plant ratings. The initial maximum transfer capacity for QNI in both directions was 300-350MW. This has been progressively increased following additional extensive testing and limit equation revisions to the present maximum transfer capacity of 700MW north and 1,078MW south. This is greater than the original design capacity of up to 500MW north and up to 1,000MW south.

The actual transfer capability across QNI varies from time to time depending on a range of conditions within the Queensland, New South Wales and Victorian networks.

In the southerly direction, QNI transfer capability is most likely to be limited by the following:

(i) Transient stability associated with loss of the largest load in Queensland;

(ii) Transient stability associated with transmission faults in Queensland;

(iii) Transient stability associated with transmission faults in the Hunter Valley (New South Wales);

(iv) Transient stability associated with a fault on the Hazelwood to South Morang 500kV line in Victoria;

(v) Thermal capacity of the 132kV transmission network between Armidale and Liddell in New South Wales; and

(vi) Oscillatory stability upper limit of 1,078MW (conditional).

In the northerly direction, the factors most likely to limit QNI transfer capability are:

(i) Transient stability associated with transmission faults in the Hunter Valley (New South Wales);

(ii) Transient and voltage stability associated with the loss of the largest generating unit in Queensland;

(iii) Transient stability associated with transmission faults in New South Wales;

(iv) Thermal capacity of the 330kV and 132kV transmission network within northern New South Wales; and

(v) Oscillatory stability upper limit of 700MW.

TransGrid and Powerlink have several committed projects which will relieve some of the above limits. For example, the committed project consisting of the installation of the phase angle regulating transformer on the Armidale to Kempsey 132kV circuit (965) will reduce the impact of limitations associated with thermal ratings across the northern New South Wales 132kV network. This project is currently under construction by TransGrid.

The impacts of committed projects within both Queensland and New South Wales have been taken into account within the economic assessment of the QNI upgrade.

# 4. OPTIONS AND COSTS CONSIDERED

TransGrid and Powerlink, in their *Annual Planning Reports (APR) 2007,* identified three primary network augmentation options for upgrading the Queensland to New South Wales Interconnector (QNI). In addition to the *APR 2007* upgrade options, TransGrid and Powerlink have investigated two other network augmentation options for increasing the transfer capability across QNI. The five feasible upgrade options with estimated costs are summarised in Table F below.

**Table F - QNI Upgrade Options**

| Option | Description | Estimated Capital Cost |
|---|---|---|
| Option 1 | Series compensation<br>This option involves the installation of series compensation across the Bulli Creek to Dumaresq and Dumaresq to Armidale 330kV circuits together with other minor supporting works. | \$120M |
| Option 2 | Northern NSW SVC<br>This option involves the installation of Static VAr Compensator (SVC) at Armidale 330kV substation. | \$35M |
| Option 3 | System Protection Schemes<br>This option involves the installation of braking resistor at Loy Yang substation in Victoria and implementation of high speed System Protection Schemes (SPS) to allow higher transfers across the existing QNI infrastructure. | \$35M |
| Option 4 | High Voltage Direct Current Back to Back System<br>This option involves the installation of a 1,500MW High Voltage Direct Current (HVDC) back to back asynchronous link located in the interconnected network between Bulli Creek and Dumaresq substations. | \$470M |
| Option 5 | Second High Voltage Alternating Current (HVAC) Connector<br>This option involves the construction of an additional 330kV double circuit transmission line and intermediate switching stations between Bulli Creek and Bayswater substations. | \$900M |

It should be noted that the five options each deliver different increments in transfer capability (refer APPENDIX 1: Transfer Capability of QNI Upgrade). Option 1 - Series Compensation would deliver an increase to QNI stability limits by up to nominally 300-400MW. In comparison, Option 2 - Northern NSW SVC and Option 3 - System Protection Scheme provide the smallest increments in QNI transfer capacity whereas Option 5 - Second HVAC Connector provides the greatest increase in transfer capacity.

Further details on each of the five options are detailed within the following sections.

## 4.1 Option 1 - Series Compensation

This option involves the installation of series capacitors across the Bulli Creek to Dumaresq 330kV double circuit line and the Dumaresq to Armidale 330kV double circuit line along with minor supporting works. The series capacitors reduce the effective reactance across the transmission lines which subsequently bring the two systems electrically closer together, thereby improving both transient and voltage stability. Series compensation, however, does not increase the thermal ratings of the circuits.

Series compensation is usually expressed as a percentage of the transmission line reactance between two reference locations. Within this report, the reference transmission circuits are between the Bulli Creek and Armidale substations.

TransGrid and Powerlink have conducted dynamic power system studies to determine the increase in power system stability for series compensation ranging from 30% to 80%. It was found that the increase in transfer capability was asymmetric. That is, the limit increase in the southerly direction was higher than in the northerly direction.

It was also found that at compensation levels around 50% the stability limit in the southerly direction reached the thermal ratings of the interconnector circuits. Hence, there was no additional gain in southerly transfer capacity for series compensation levels higher than around 50%.

A series of market simulation studies were conducted to determine the market benefits associated with compensation levels ranging from 30% to 70%. Higher levels of compensation resulted in more market benefits due to the increase in QNI transfer capability. However, higher levels of compensation are also more costly.

Power system studies showed that compensation levels above 50% required series capacitor platforms at an additional location (to meet voltage level criteria) which resulted in a significant increment in capital cost. At the same time, the increase in stability in the southerly direction could not be fully utilised due to encroachment on thermal ratings.

The comparison of market benefits against cost showed that the optimum level of series compensation was 50%.

TransGrid and Powerlink also engaged specialist consultants to examine potential impacts of sub-synchronous resonance from the installation of series capacitors. The studies found that sub-synchronous resonance could occur under certain generator and transmission system conditions across all series compensation levels.

The series compensation option therefore incorporates a component of variable thyristor controlled series compensation. This variable element allows potential sub-synchronous resonance to be “tuned out”. The variable series compensation can also improve damping of inter-area modes of oscillation by modulating the level of compensation.

The total cost of the proposed works under this option has been estimated at $120M in $07/08[9].

[9] To the accuracy of ± 25%.

## 4.2 Option 2 - Northern NSW Static VAr Compensator

Under certain system and generating conditions, the northerly transfer capability across QNI may reach very low levels due to voltage stability limitations associated with a trip of a fully dispatched large generating unit within Queensland. This limit is also impacted by increasing northern New South Wales load demands which reduces reactive reserves within the area.

This option involves the installation of a Static VAr Compensator (SVC) at Armidale substation[10] to increase the level of dynamic reactive reserves within the northern New South Wales network subsequently increasing the level of northerly QNI transfer capability.

The total cost of the proposed works under this option has been estimated at $35M in $07/08[11].

## 4.3 Option 3 - Extended Limits Using System Protection Schemes

The transfer capability across QNI is set by a series of transient stability, voltage stability and thermal ratings following transmission, generator and load contingencies. This option involves the implementation of fast acting protection schemes to mitigate large power system disturbances following contingency events.

The scheme requires pre-determined responses to be automatically taken following critical contingencies to reduce the level of disturbance on the power system. Hence, by reducing the impacts of the disturbance on the system following the contingency, the existing interconnector infrastructure can operate at higher levels prior to the contingency.

This option involves the use of control, communication and switching systems to implement the fast acting protection measures. However, in order to fully gain the benefits of this scheme, this option also requires the installation of a braking resistor at Loy Yang substation in Victoria to address QNI transient stability limitations associated with a fault within the South Morang to Hazelwood 500kV transmission system.

This option also involves entering into prior binding contractual arrangements with the owners of suitable generating units or bulk loads to instantaneously trip following the contingency event in order to mitigate the impacts of power swings and oscillations.

While this option may involve lower capital cost (and construction lead times) than other options, it also results in significantly less capacity increase than other options. The increase associated with this incremental option is predominately unidirectional. Annualised costs of the necessary ongoing non-network contractual arrangements will add to the cost of this option. In addition, TransGrid and Powerlink would need to implement duplicate schemes and backup systems to ensure equivalent levels of reliability to other options.

The total cost of the proposed works under this option, excluding amortised costs of non-network contractual arrangements, has been estimated at $35M in $07/08[12].

[10] TransGrid has commenced studies assessing the installation of a SVC at Armidale as an option to meet reliability of supply obligations in Northern NSW and has sought some funding for this in its 2009-14 revenue proposal to the AER. This project has not been included as a modelled project in this study.
[11] To the accuracy of ± 25%.
[12] To the accuracy of ± 25%.

## 4.4 Option 4 - HVDC Back to Back System

This option involves the installation of a High Voltage Direct Current (HVDC) back to back converter station which isolates the alternating current components of the Queensland and southern state transmission networks. This subsequently improves transient, voltage and oscillatory stability to the point where thermal ratings become the limiting elements impacting on QNI transfer capability.

The HVDC back to back scheme will be required to be located within the Bulli Creek to Dumaresq 330kV part of the interconnected system. Locating the HVDC link in this area will separate the entire Queensland and far northern New South Wales (Tweed) network from the southern system.

TransGrid and Powerlink have examined the short circuit levels of the transmission systems following installation of the HVDC back to back system. The studies indicate that the strength of the power system on the New South Wales side is insufficient to support conventional thyristor based switching technology within the HVDC system, and require the newer technology insulated gate bipolar transistor switching devices.

The total cost of the proposed works under this option has been estimated at $470M in $07/08[13].

## 4.5 Option 5 - Second HVAC Connector

This option involves the construction of a second High Voltage Alternating Current (HVAC) interconnection between Queensland and New South Wales. The scope of works includes the construction of a new 330kV double circuit high capacity transmission line from Bulli Creek substation (in Queensland) to Bayswater substation (in New South Wales) and the provision of intermediate switching stations, switchgear, shunt reactors, shunt compensation, protection and control equipment.

This option will deliver a substantial increase in the transfer capability between Queensland and New South Wales. As with the existing interconnection, the transfer capability will be set by transient, oscillatory and voltage stability.

At this point in time, TransGrid and Powerlink have not secured transmission line easements required for this option.

The total cost of the proposed new 330kV double circuit high capacity transmission line has been estimated at $900M in $07/08[14].

[13] To the accuracy of ± 25%.
[14] To the accuracy of ± 25%.

# 5. SCENARIOS CONSIDERED

The Regulatory Test requires the cost and benefits of options to be assessed under a range of reasonable market development scenarios. The scenarios are required to consider:

- Existing and future transmission developments;
- Variations in demand growth;
- Potential generation and demand side developments; and
- Generator bidding strategies.

## 5.1 Existing and Future Transmission Developments

Existing and future transmission developments to meet forecast demand growth are assumed to occur independently of an upgrade of the Queensland to New South Wales Interconnector (QNI). The modelled transmission projects are consistent with committed and routine projects detailed within the National Electricity Market Management Company's (NEMMCO) 2007 *Annual National Transmission Statement*.

## 5.2 Variations in Demand Growth

The economic assessment was carried out against low, medium and high economic growth scenarios under typical 50% Probability of Exceedance (PoE) temperature forecasts.

## 5.3 Existing and Future Generation Projects

The market modelling used for the economic assessments incorporated existing and committed generation projects as detailed within NEMMCO's 2007 Statement of Opportunities. In addition, new entrant generation was incorporated to meet forecast demand growth across the simulation time frame.

New generator entry has been based on a market driven commercial viability basis and using information from the ACIL Tasman "Report on NEM Generator Costs 2007".

## 5.4 Generator Bidding Strategies

The market modelling incorporated both Short Run Marginal Cost (SRMC) and "realistic" generator bidding behaviour consistent with the Regulatory Test. Realistic bidding was based on supply side equilibrium where generating portfolios attempt to bid into the market to maximise profits assuming a highly inelastic demand response[15].

The SRMC bidding assumes that generating plant bids at the cost of production and represents highly competitive bidding behaviour.

[15] Demand elasticity was modelled using price sensitivity load blocks consistent with data included in NEMMCO's 2007 *SOO.*

## 5.5 Summary of Scenarios

The scenarios used within the economic assessment are summarised within Table G below.

**Table G - Market Development Scenarios**

| Scenario | Description |
|---|---|
| Scenario A | Medium economic growth using “realistic” generator bidding behaviour. |
| Scenario B | High economic growth using “realistic” generator bidding behaviour. |
| Scenario C | Low economic growth using “realistic” generator bidding behaviour. |
| Scenario D | Medium economic growth using short run marginal cost (SRMC) generator bidding behaviour. |

The Regulatory Test states that for an option to satisfy the market benefits limb of Regulatory Test, it must maximise the Net Present Value of market benefit compared with alternative options and timings in a majority (but not necessarily all) of reasonable scenarios. In applying the Regulatory Test, TransGrid and Powerlink have treated all scenarios as having equal weighting.

However, it is noted from Table G that Scenarios A and D are both based on medium economic growth. While this has the practical effect of assigning a higher weighting to the medium economic growth scenario and lower weightings to each of the low and high economic growth scenarios, medium economic growth is the most likely expected growth outcome based on present knowledge of the National Electricity Market. TransGrid and Powerlink regard this as a reasonable approach.

# 6. MARKET BENEFITS

## 6.1 Types of Market Benefits

The Regulatory Test defines market benefit as the total benefits of an option to all those who produce, distribute and consume electricity in the National Electricity Market (NEM). Market benefits include the change in consumer and producer surplus, but specifically exclude the transfer of surplus between consumers and producers.

The market benefits consist of the following components:

(i) Reduction in Generation Dispatch Costs

An interconnector upgrade may result in more efficient generation dispatch outcomes if the increase in transfer capability alleviates constrained operation. For example, the increase in capacity could result in higher generation levels from lower cost coal fired plant operating in lieu of more costly open cycle gas fired generation, which subsequently translates to an overall economic benefit.

The reduction in generation dispatch costs within the market simulations are determined by calculating the difference between the total dispatch cost within the NEM (i.e. product of the dispatch energy and the short run marginal cost for each generating unit) between the base case (i.e. do nothing) and upgrade options. The cost of production also includes operation and maintenance costs.

For hydro plant, the dispatch costs were determined using water volume price curves which allowed the value of water for generating electricity to be calculated as a function of water storage levels.

(ii) Reduction in Voluntary Load Curtailment

Demand side participation is modeled within the market simulations in accordance with information published within the National Electricity Market Management Company's Annual National Transmission Statement Data and Assumptions document.

Demand side participation represents the price at which electricity consumers (residential, commercial and industrial) are prepared to have nominated quantities of load curtailed. This represents the value of energy for these consumers.

An interconnector upgrade which results in lower electricity prices may reduce the level of voluntary load curtailment and increase the output of higher value product. This translates into an overall economic benefit to the market.

(iii) Reduction in Involuntary Load Shedding

An interconnector upgrade which results in lower levels of unserved energy (through the sharing of generator reserves) provides an economic benefit through increasing the output of higher value product. The value of unserved energy may be assumed to be the market Value of Lost Load ($10,000/MWh) or another value determined through customer surveys.

Within this report, sensitivities to unserved energy across the range $10,000/MWh to $30,000/MWh were carried out.

(iv) Deferral of new generation entry

An interconnector upgrade may defer the need for additional generating capacity through the sharing of generation reserves. The deferment of generation resulting from higher levels of interconnector capacity between regions is an economic benefit to the market.

(v) Competition Benefits

Competition benefits are the benefits resulting from an increase in competition between generators delivering lower prices across the NEM. The competition benefits are integrated within the calculation of the market benefits mentioned above and have not been reported separately within this document.

## 6.2 Total Market Benefits

The total market benefits are the summation of all the market benefit categories mentioned within the sections above.

# 7. MODELLING AND ASSUMPTIONS

## 7.1 Methodology

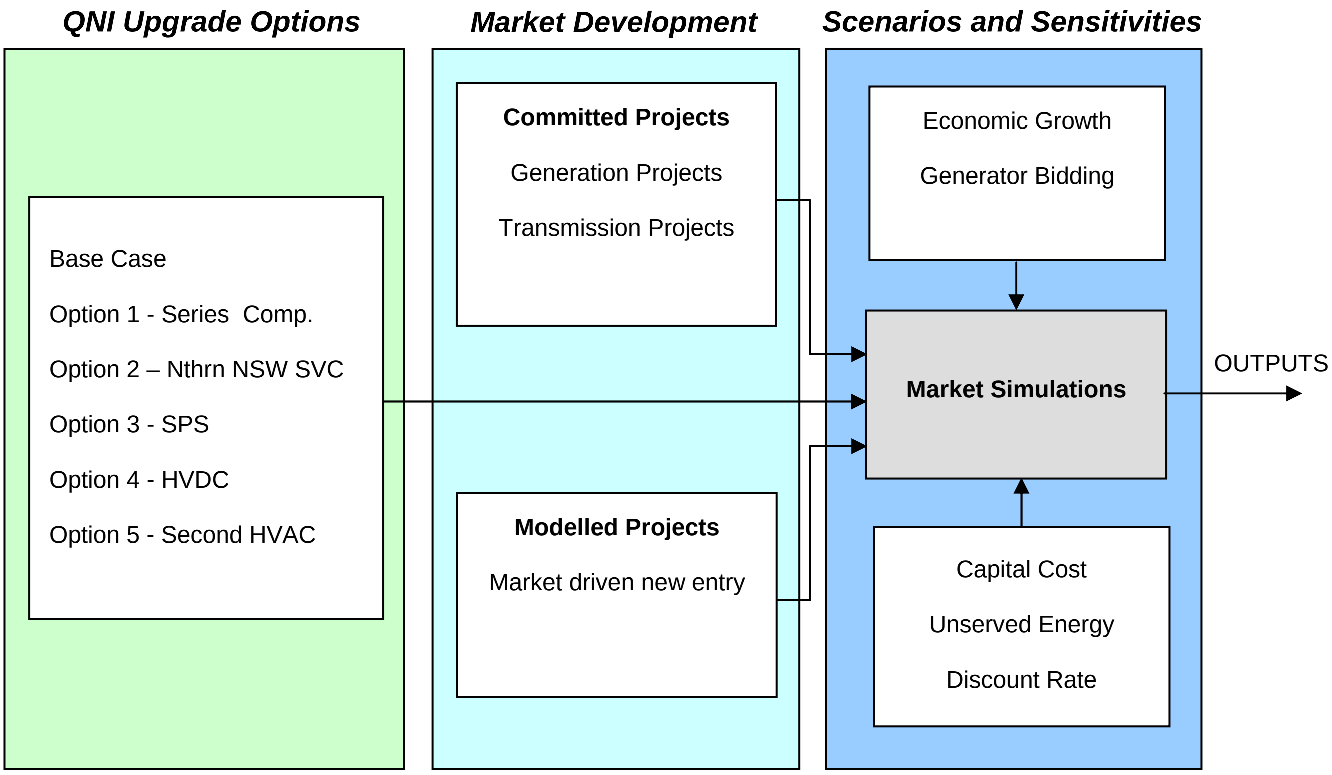
The Regulatory Test contains guidance relating to the extent of studies and sensitivities that are required to be carried out to demonstrate that the proposed augmentation maximises the net market benefits.

TransGrid and Powerlink consider that the most effective means of analysing net market benefits to meet the requirements of the Regulatory Test is through the use of forward looking market simulations.

The market model used for carrying out the market simulations incorporates a generation dispatch and market clearing process to replicate the operation of the National Electricity Market (NEM). The data and assumptions used within the market simulation process are detailed within this section.

The methodology used to calculate the market benefits is shown within Figure 3 .

**Figure 3 - Market Benefit Calculation Methodology**




### 7.1.1 Base Case

The "base case" represents the current and future operation of the electricity market in the absence of upgrading the Queensland to New South Wales Interconnector (QNI). The base case was used as a reference point to determine the relative benefits of the QNI upgrade options.

### 7.1.2 Modelled Projects

The market simulation process includes new entry generation (in addition to committed projects) to meet forecast demand growth. These new generator entrants were determined using a market driven model development approach in accordance with Clause 14(b) of the Regulatory Test.

### 7.1.3 Market Model

The calculation of market benefits uses the process of forward looking market simulations. The market simulations were carried out by specialist consultants using advanced software which models the operation of the NEM.

### 7.1.4 Generator Bidding

Both realistic and Short Run Marginal Cost (SRMC) bidding behaviour of generators were modelled in the market development scenarios. Realistic bidding emulates the imperfect competitive nature of the market and the generator's behaviour as they adjust their bids to maximise profits.

Indirect impacts of the Commonwealth Government's proposed emissions trading scheme and revised Mandatory Renewable Energy Targets which may result in material changes to generator bidding behaviour and new generation investment have not been included in the model. While emission trading and mandated renewable energy impacts are likely to affect the market simulations, these schemes are not firm at this point in time.

### 7.1.5 Simulation Time Frame

The market simulations were carried out across a 13-year time frame commencing with the 2007/08 financial year. The 13-year time frame allows for a ten year analysis of market costs and benefits following a notional three year lead time for project implementation and commissioning.

### 7.1.6 Sensitivities

Sensitivity of the net market benefits to the upgrade option capital cost, discount rate and cost of unserved energy were carried out.

## 7.2 Model Inputs

### 7.2.1 Network Topology

The network topology used in the QNI upgrade studies was based on a multi-zonal network model for the interconnected NEM system. The market model incorporated a Direct Current load flow which allowed the calculation of power transfers between nodes. This enabled forecast power transfers to be more effectively compared against transfer limits in order to determine the level of constraints.

The impedances for the load flow model were calculated by reducing and benchmarking the full Alternating Current transmission network to an equivalent reduced model.

### 7.2.2 Load Profiles

Load profiles used within the forward looking market simulation model were based on historical load traces which were scaled up to match the forecast maximum demand and energy.

The energy and demand forecasts used within the modelling were based on data contained within the National Electricity Market Management Company's (NEMMCO) 2006 Statement Of Opportunity (SOO). This was the latest forecast data at the time of testing and carrying out the market simulations. A comparison of the forecasts within NEMMCO's 2007 SOO was carried out and it was found that there would be no material change to the results.

The market simulations were carried out over a 13-year time frame. The forecasts for the additional three years were calculated by linearly extrapolating the 10-year forecasts.

### 7.2.3 Generation Projects

The market simulations included the following generation projects within the Queensland and New South Wales regions:

Queensland:

- Condamine Combined Cycle Gas Turbine (160MW) for July 2009;
- Braemar Stage 2 Combined Cycle Gas Turbine (450MW) by October 2009; and
- Darling Downs Combined Cycle Gas Turbine (630MW) by April 2010.

New South Wales:

- Tallawarra Combined Cycle Gas Turbine (420MW) for July 2008;
- Uranquinty Open Cycle Gas Turbine (630MW) by October 2008; and
- Colongra Open Cycle Gas Turbine (660MW) by October 2009.

### 7.2.4 Generation Data

The generation data assumed within the studies was consistent with information published within the NEMMCO's *Annual National Transmission Statement* 2007 Data and Assumptions document.

# 8. RESULTS

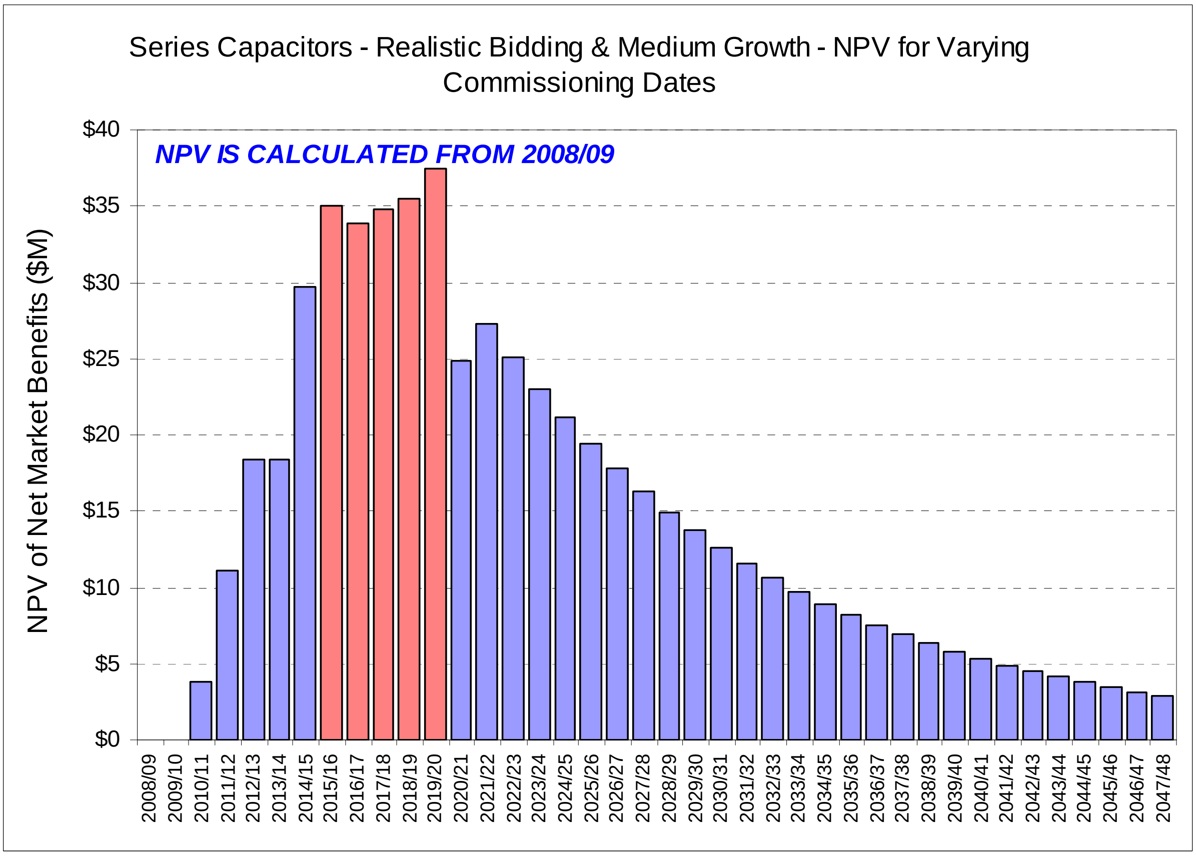
The economic cost-benefit analysis undertaken considered the optimal timing and Net Present Value (NPV) of the market benefits (i.e. present value of market benefits minus present value of augmentation costs) derived from the market simulation for each augmentation option. The analysis was based on a 30-year assessment from 2007/08 to 2037/38 and the assumption that the market benefits following the 13-year market simulation timeframe continue at the same rate as the average of the last three years of the simulation.

The results of this analysis are explained and summarised in the sections below. Full details of the cost-benefit analysis are contained in APPENDIX 2: Economic Analysis.

## 8.1 Optimal Timing

The optimal economic timing for the commissioning of each upgrade option for each of the studied scenarios was evaluated. The optimal timing was determined by calculating the Present Value (PV) of the net market benefits for a range of possible commissioning dates. Where there was a range of commissioning dates that could maximise the PV of the net market benefits, then the earliest commissioning date of the range has been used for the purpose of the study. As an example, Figure 4 illustrates the optimal economic timing for Option 1 under Scenario A. As shown within this figure, the net market benefit is maximised between 2015/16 and 2019/20 following which there is a trend of declining PV of the net market benefits. In this case, the earliest optimal timing of 2015/16 has been used in the financial modelling.

**Figure 4 - Optimal Economic Timing Illustration**



For some options under certain scenarios, the annual market benefits do not exceed the annualised equivalent cost of the option in any of the market simulation study years. In these situations, these options do not have an economic timing. Consequently, further market analysis and optimal timing determinations were not undertaken for these economically "inferior" options in the interest of study cost efficiency.

The optimal timing for each Queensland to New South Wales Interconnector (QNI) upgrade option is shown within Table H. As can be seen, the options under the scenarios that did not achieve a positive net market benefit over the study period includes Option 4 - HVDC Back to Back System, Option 5 - Second HVAC Connector and Option 2 - Northern NSW SVC specifically under Scenario C. In these cases, the net present value of market benefits was calculated using timing based on a minimum lead time of three years.

**Table H - Optimum (Economic) Timing for QNI Upgrade Options**

| Options | Scenarios | | | |
|---|---|---|---|---|
| | A | B | C | D |
| 1. Series Compensation | 2015/16 | 2009/10 | 2020/21 | 2013/14 |
| 2. Northern NSW SVC | 2016/17 | 2013/14 | (-)[16] | 2014/15 |
| 3. System Protection Scheme | 2018/19 | n/a[17] | n/a | n/a |
| 4. HVDC Back to Back Station | (-)[16] | n/a | n/a | n/a |
| 5. Second HVAC Connector | (-)[16] | n/a | n/a | n/a |

From Table H, the optimal timing for Option 1 - Series Compensation under the most likely medium growth Scenarios A and D is 2015/16 and 2013/14 respectively. It is not surprising that the optimal timing for Option 1 - Series Compensation is earlier (2009/10) under the high growth Scenario B and later (2020/21) under the low growth Scenario C. In comparison to Option 1 - Series Compensation, the optimal timing for Option 2 - Northern NSW SVC is about one year later under the medium growth scenarios.

## 8.2 Cost-benefit Analysis

An economic cost-benefit analysis was carried out to calculate and compare the present value of the net market benefits (market benefits less costs) for each option to the base case (i.e. no augmentation) under the range of reasonable scenarios considered (see Table G for the scenarios).

[16] No optimal timing was established as market benefits never exceeded the equivalent annualised cost of the augmentation.
[17] n/a in Table H represents where market simulations were not carried out.

A 30-year analysis period was selected as an appropriate period for financial analysis when having regard to the variability and uncertainty of market conditions over the longer term. As the market benefit simulation results were based on a 13-year modelling period[18], the market benefits for the balance of the 30-year analysis period were assumed to continue at the same rate as the average of the last three years of the simulation.

A discount rate of 9% was selected as a relevant commercial discount rate and sensitivity analysis were conducted to test this assumption. All costs and benefits are measured in 2007/08 dollars and a 40-year asset life is assumed.

Under the Regulatory Test, an option satisfies the test where it maximises the Net Present Value (NPV) of the market benefit (i.e. present value of market benefits less the present value of costs) compared with alternative projects and timings in a majority of (but not necessarily all) reasonable scenarios.

The market cost-benefit analysis was conducted in two stages. The first stage consisted of calculating the net market benefits for all options under the most plausible scenario (i.e. Scenario A - medium economic growth and realistic generator bidding behaviour). It was found that the net market benefits of options 3, 4 and 5 were marginal or negative. The NPV of net market benefits for each option under Scenario A are provided within Table I.

**Table I - NPV of the Net Market Benefits for Scenario A[19]**

| Option | NPV ($M) |
|---|---|
| Option 1 - Series Compensation | $35 |
| Option 2 - Northern NSW SVC | $102 |
| Option 3 - System Protection Scheme | $5 |
| Option 4 - HVDC Back to Back System | - $206 |
| Option 5 - Second HVAC Connector | - $277 |

The second stage of the cost-benefit analysis consisted of evaluating the market benefits of the more viable options identified within the first stage of analysis.

The analysis indicates that the annual market benefits of some options may be several times the annualised costs of the augmentation option, however these significant benefits tend to accrue later in the study period. Figure 5 illustrates the expected market benefits measured against the expected costs for Option 1 - Series Compensation under the low, medium and high economic growth scenarios with “realistic” generator bidding.

[18] The cost-benefit analysis covering Scenario B (high economic growth) was based on a ten-year market simulation period due to the volatility in market benefits in the last three years.
[19] The NPV values are rounded to the nearest million dollars.

## Figure 5 - Benefits versus Costs Illustration [20]

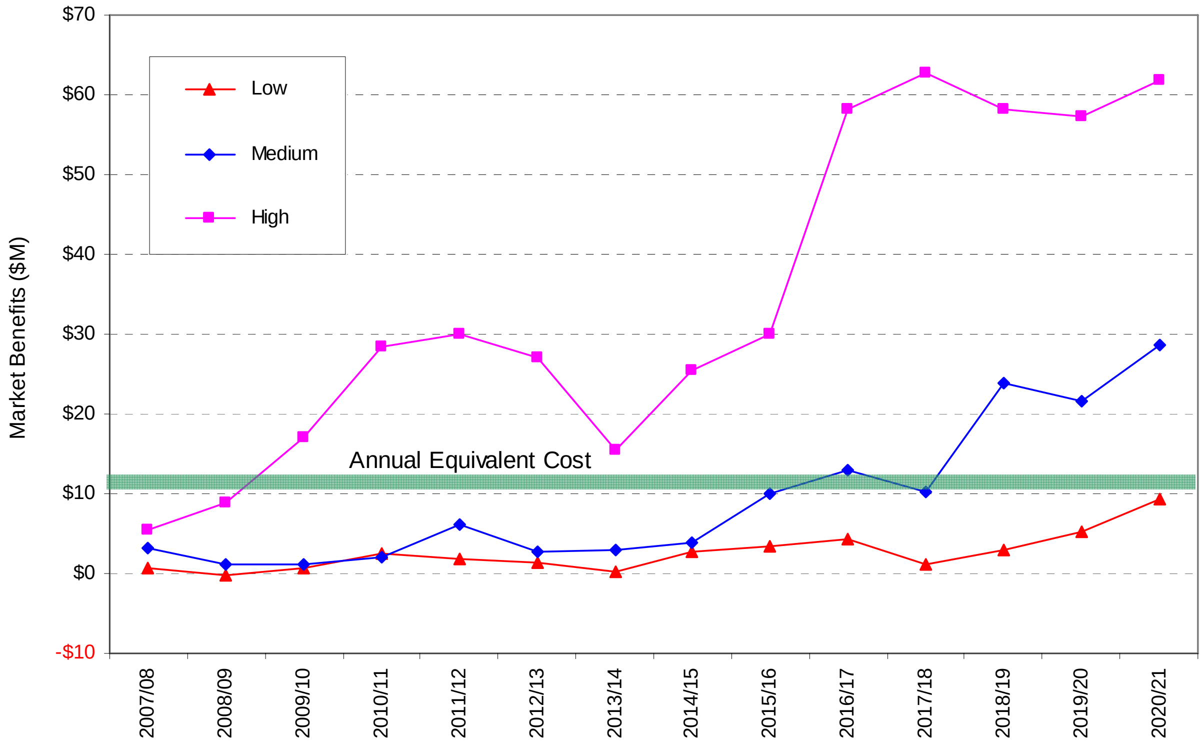



Table J summarises the economic analysis contained in APPENDIX 2: Economic Analysis and shows the NPV of market benefit for each option and identifies the best-ranked option under the range of scenarios considered.

## Table J - NPV of the Net Market Benefits for Options 1 and 2 [21]

| Option | Scenario A | | Scenario B | | Scenario C | | Scenario D | |
|---|---|---|---|---|---|---|---|---|
| | *Medium Economic Growth and "Realistic" Generator Bidding* | | *High Economic Growth and "Realistic" Generator Bidding* | | *Low Economic Growth and "Realistic" Generator Bidding* | | *Medium Economic Growth and SRMC Generator Bidding* | |
| | NPV ($M) | Rank | NPV ($M) | Rank | NPV ($M) | Rank | NPV ($M) | Rank |
| 1 - Series Compensation | $35 | 2 | $288 | 1 | - $35 | n/a | $270 | 1 |
| 2 - Northern NSW SVC | $102 | 1 | $174 | 2 | - $32 | n/a | $196 | 2 |

From Table J, Option 1 - Series Compensation delivers the highest net market benefit in two scenarios (i.e. Scenarios B and D). In comparison, Option 2 - Northern NSW SVC has the highest net market benefit under one scenario (i.e. Scenario A). Under Scenario C, the present value of costs for Options 1 and 2 do not return a positive net market benefit and therefore market benefits are maximised without augmentation (i.e. Base Case).

The optimum timing for Option 1 - Series Compensation under Scenario A - medium economic growth and "realistic" bidding behaviour is 2015/16. The optimum timing for Option 2 - Northern NSW SVC is a year later in 2016/17.

[20] Benefits are shown as a 3-year moving average.
[21] The NPVs are rounded to the nearest million dollars.

Whilst TransGrid and Powerlink are inclined to regard the "realistic" generator bidding under Scenario A as more plausible than Short Run Marginal Cost bidding under Scenario D, it is noted that the latter produces optimal timings which are two years earlier than Scenario A.

Based on the optimum timing for Option 1 - Series Compensation of 2015/16 and 2013/14 under Scenarios A and D respectively, as well as the later timing of Option 2 - Northern NSW SVC in 2016/17, TransGrid and Powerlink consider that it is premature to recommend an augmentation option at this time. However, both organisations will continue to monitor market developments which could materially impact on the timing of a potential upgrade. Triggers for conducting further analysis may include a consistent above average load growth totalling 2,000MW across all regions in the National Electricity Market over several years, or where the optimal timing may be advanced due to the entry of as yet uncommitted new generation scheduled for commissioning from 2012 onwards which was not included in the market modelling.

Any updates will be communicated through Powerlink's and TransGrid's *Annual Planning Reports*.

## 8.3 Sensitivity Analysis

In addition to examining the net market benefits of upgrade options across a range of reasonable scenarios, the sensitivity of the option ranking to other critical parameters was examined. The sensitivity was carried out by examining the ranking under random variation of parameters using Monte-Carlo techniques[22].

The parameters, distribution and range of values used within the sensitivity study are shown in Table K.

**Table K - Distribution and Range of Parameters used within the Sensitivity Analysis**

| Parameter | Range |
|---|---|
| Capital Cost | The capital cost of the proposed augmentations was tested for sensitivity to variations of plus or minus 25% from the expected value. The variation in each cost was modelled as a triangular distribution with the assumption that the costs are statistically independent. This means that the cost of each network augmentation option is allowed to vary within plus and minus 25% independently of the over or underspend of the other components. |
| Cost of Unserved Energy | The sensitivity to the average cost of unserved energy was tested by allowing this parameter to vary randomly between $10,000/MWh and $30,000/MWh using a triangular distribution with a mean of $20,000/MWh. |

[22] @Risk add-in tool for Microsoft Excel.

The Monte-Carlo analysis assigns a value to each of the parameters in Table K according to its distribution and then ranks the options. This simulation is done many times (in this case 10,000 times) to cover a large number of parameter combinations. The analysis identifies which option is best-ranked (i.e. the option that has the highest net market benefits for the largest number of samples) and gives the frequency for which this option 'wins'.

In addition to the above, the sensitivity of the ranking of options to the discount rate assumption was also investigated by repeating the above analysis with discount rates of 7%, 9% and 11%.

The sensitivity study was limited to Option 1 - Series Compensation and Option 2 - Northern NSW SVC across the range of scenarios considered. These options were considered because the net market benefits of options 3, 4 and 5 were found to be marginal or negative under Scenario A (being the most plausible market development scenario).

The 'winning option' and frequency for which it 'wins' within the Monte-Carlo analysis for each scenario and discount rate is shown within Table L.

**Table L – Sensitivity Analysis of Options 1 and 2**

| Scenario | Discount Rate | | |
|---|---|---|---|
| | 7% | 9% | 11% |
| Scenario A - Medium Economic Growth and “Realistic” Bidding | Option 2 (100%) | Option 2 (100%) | Option 2 (100%) |
| Scenario B - High Economic Growth and “Realistic” Bidding | Option 1 (100%) | Option 1 (100%) | Option 1 (100%) |
| Scenario C - Low Economic Growth and “Realistic” Bidding | Base Case (100%) | Base Case (100%) | Base Case (100%) |
| Scenario D - Medium Economic Growth and SRMC Bidding | Option 1 (100%) | Option 1 (100%) | Option 1 (100%) |

Table L above shows Option 1 - Series Compensation as the 'winning option' under the majority of scenarios and discount rates across the range of parameters assessed (except for Scenario C where the market benefits are maximised without the augmentation). As can be seen in this table, the sensitivity analysis indicates that the results are robust to variations in capital cost, unserved energy and discount rate.

## 8.4 Results Summary

On the basis of the cost-benefit and sensitivity analysis, Option 1 - Series Compensation would satisfy the Regulatory Test with an optimal economic timing of 2015/16.

As previously indicated, the Interim Report was not a formal Application Notice required under the Rules. TransGrid and Powerlink believe that the analysis which underpins this report is sufficient to support an Application Notice, but that it is premature to proceed to that step at this point in time given that the optimal timing is 2015/16.

# 9. CONSULTATION SUBMISSIONS

TransGrid and Powerlink published an Interim Report for Public Consultation on the outcomes of the detailed technical and economic studies into the upgrade of QNI in March this year, and invited submissions from Registered Participants and interested parties to provide feedback on the analysis and conclusions detailed within the Report.

TransGrid and Powerlink have received submissions from three parties as follows:

- Delta Electricity;
- Energy Users Association of Australia; and
- Queensland Government Department of Mines and Energy.

TransGrid and Powerlink have summarised the issues raised within the submissions, and grouped them into the following categories as follows:

<u>The AER Regulatory Test</u>

*The existing Regulatory Test does not deliver efficient outcomes to end users within the NEM and has restricted the development of a truly national market.*

*The market benefits limb of the Regulatory Test has proved to be problematic and the failure of the test to provide support for the construction of a single interconnector (or upgrade) is a cause of major concern.*

*The shortcomings within the Regulatory Test have prevented the timely construction of much needed interconnectors within the NEM.*

*Wealth transfers must be considered as part of the application of the Regulatory Test since one of the key principles of the NEM is about delivering maximum benefits to end users and to focus on the long term interests of consumers of electricity.*

Response:

It is a requirement of the National Electricity Rules (Clause 5.6.6) that an Application for a new large transmission network asset be demonstrated to satisfy the AER Regulatory Test. While not proposing to establish a new large network asset, Powerlink and TransGrid have conducted analysis to meet the requirements of the Regulatory Test. An upgrade of QNI has been assessed under the market benefits limb of the Regulatory Test because the project is not necessitated solely by the inability to meet mandated reliability standards.

TransGrid and Powerlink are obliged to apply the AER Regulatory Test as it exists.

The AER Regulatory Test (Clause 5) specifically excludes the transfer of surplus between consumers and producers (i.e. wealth transfers) in the evaluation of market benefits of an upgrade option. Accordingly, wealth transfers are not permitted, and have not been included, in the evaluation of the net market benefits of an upgrade to QNI.

The AER Regulatory Test also requires the optimal timing of an upgrade to be in the year in which the net market benefits are maximised. It is noted that the analysis indicates an earlier commissioning date would still provide net market benefits but these are less than the maximum benefits. It is understood that the AER will be required, as part of the AEMC's recommendations on the national transmission planner, to review its guidelines for the Regulatory Test. This represents an opportunity for interested parties to raise with the AER any perceived shortcomings in the Regulatory Test.

<u>Application of the Regulatory Test</u>

*The methodology employed in determining the timing and defining the nature of the most suitable QNI upgrade is for the most part sound and well-reasoned.*

*The growth scenarios applied seem to be relevant and reasonable to use in an assessment of a QNI upgrade.*

*The emphasis on the medium growth economic scenario seems to be prudent under the circumstances.*

*The report is a good example of two transmission network owners undertaking work in collaboration on significant inter-regional issues.*

Response:

While the Interim Report for Market Consultation is not an Application Notice under the National Electricity Rules, TransGrid and Powerlink have carried out the detailed studies in a manner such that the project assessment complies with the provisions of the Regulatory Test.

TransGrid and Powerlink agree that an emphasis on the medium economic growth scenario is a reasonable approach based on presently available information within the NEM.

Powerlink and TransGrid have worked together closely on this project with significant exchange of expertise and sharing of information occurring during all phases of the study. The two network service providers have also collaborated with other planning bodies within the NEM on this study.

<u>Assessment of an Optimum Upgrade Timing</u>

*Successive examinations of an upgrade to QNI seem to push back the optimal timing every time new generation is committed resulting in the project timing always falling outside the window of commitment.*

*The comparatively shorter lead times for building new generation versus a major new interconnector upgrade seem to result in generation investment crowding out significant inter-regional transmission projects.*

*The approach to maximising the present value of the net market benefits seems reasonable although there is concern regarding the impact this has in delaying the upgrade of QNI.*

*There are no regulatory impediments to committing to a project now although it can be seen that uncertainties such as emission trading and future generation developments have led to the decision not to proceed with a commitment for the upgrade at this time.*

*An appropriate balance is needed between the optimal timing based on maximum market benefits as required by the Regulatory Test and uncertainty surrounding regulated transmission investment on generator projects within the competitive market.*

*It is appropriate that the NSW 500kV conversion project to increase transmission capability and maintain reliability of supply to customers within Newcastle/Sydney/Wollongong area has a higher priority than augmentation of QNI, and that the 500kV conversion as the first stage to increase capacity to NSW customers is supported.*

Response:

Powerlink and TransGrid are obligated to apply the Regulatory Test in its currently specified form.

The net market benefits and optimum timing of an upgrade to QNI are dependent on many factors, including the commitment and location of new generation development. TransGrid and Powerlink note that that the commitment of new generating stations can alter the optimal timing of an upgrade to QNI. The studies and outcomes detailed within the Interim Report were based on information available at the time.

The studies found that the optimal timing for Option 1 - Series Compensation under the most plausible scenario (Scenario A - medium economic growth and realistic generator bidding behaviour) was 2015/16. This is the timing that <u>maximises</u> the NPV of the net market benefits compared to a range of alternative timings. The determination of the timing which maximises the NPV of the net market benefits is a requirement of the Regulatory Test.

Although the NPV of the net market benefits for Option 1 - Series Compensation under Scenario A is positive from 2010/11 onwards, the NPV is not maximised until 2015/16. This is because the market benefits do not exceed the annualised equivalent cost of the augmentation prior to 2015/16, even though the NPV of the net market benefits across the 30 year time frame is positive.

The matter of the required assessment of the optimal timing has been addressed above.

In terms of whether Powerlink and TransGrid should commit now to an upgrade for 2015/16, it is noted that such an upgrade is a contingent project in the current regulatory period for both entities, and that the identified optimal timing lies beyond those regulatory periods, and indeed beyond the coming regulatory period for TransGrid. TransGrid has proposed an upgrade to QNI to be a contingent project as part of its recent Revenue Proposal to the AER. This will allow for expenditure to commence within TransGrid's coming regulatory control period if required.

In short, TransGrid and Powerlink consider it premature to commit to the construction of a large transmission network asset almost seven years prior to the optimum commissioning timing. It is noted that the Garnaut draft report on climate change policy has postulated that there may be a "public good" benefit in there being stronger interconnectors during the transition to a lower emissions generation mix. Such a benefit lies outside the present specification of the AER Regulatory Test. It is expected that this matter will be considered in the upcoming AEMC review of the NEM arrangements which has been commissioned by the MCE.

TransGrid's and Powerlink's views regarding the sequencing of transmission augmentations are shaped solely by outcomes determined through application of the Regulatory Test. The NSW 500kV conversion was necessitated to meet mandated reliability standards to customers within the Newcastle, Sydney and Wollongong area, and was assessed under the reliability limb of the Regulatory Test. This project has an earlier timing than that indicated for an upgrade to QNI.

Forecast Performance across QNI

*Based on the committed generation developments within both NSW and Queensland, the future southward energy transfers across QNI are likely to be consistent with levels experienced during the 2005/06 and 2006/07 financial years for which an upgrade may not necessarily deliver benefits.*

*There is concern that the market simulations show that failure to upgrade QNI at this time will result in a significant increase in transmission constraints across the interconnector which will inevitably result in higher spot prices feeding into higher energy costs for end users into the next decade.*

Response:

TransGrid and Powerlink note that the forward looking market simulations carried out as part of the Regulatory Test economic assessment provide an indication of future market performance under a specific set of assumptions and scenarios.

For the interest of the market, TransGrid and Powerlink have published forecast constraint times as evaluated by the forward looking market simulations for a specific set of assumptions relating to Scenario A (medium economic growth and realistic bidding). Further information on these results are detailed within Section 3.2.

The economic impacts of the forecast constraints have been included in the analysis, consistent with the provisions of the AER Regulatory Test i.e. "wealth transfers" are specifically excluded.

Northward Capability across QNI

*The northward transfer capability across QNI has deteriorated since the Kogan Creek generating unit commenced service*

*It is not uncommon for the northward QNI transfer across QNI to be lower than 400MW which is odds with the statement that the maximum northward transfer of QNI is 700MW.*

*The northward QNI transfer capability may further reduce in time due to increasing load growth within northern NSW and subsequent impacts on voltage stability across the interconnection.*

*There may be some conservatism in the existing limit equation associated with discounting the raise contingency services provided by the Queensland generators and assumptions relating to the operation of capacitor banks within northern NSW.*

*TransGrid should bring forward the timing of the second SVC at Armidale to address voltage stability within northern NSW which will reduce the reliance of power supply within the area from Queensland and prevent the northern QNI transfer capability from further deteriorating*

Response:

As for many network sections in the NEM, the northerly and southerly transfer limits across QNI are dynamic; that is the actual transfer limit will vary from time to time depending on a range of power system and market conditions across the whole NEM. Some of the power system contingencies which can impact on the transfer capability of QNI are detailed within Section 3.1.

The commissioning of new generation, loads or transmission projects across the NEM can change the transfer capability of major network sections, including QNI, and interconnector transfer limits are regularly reviewed, particularly following changes to the power system.

The operation of Kogan Creek at high output under certain conditions may limit northerly QNI transfer due to the voltage stability issues which would arise from a trip of this unit. However, the overall supply demand balance within the Queensland region generally increases when Kogan Creek is operating at high levels.

A relatively high power transfer capability in a northerly direction across QNI may be reached under certain market and power system conditions. Nonetheless, Powerlink and TransGrid have observed that high northerly QNI transfers do not occur very often, with power transfers occurring in the southerly direction for the majority of the time.

Under high northern NSW demand conditions, both voltage stability and thermal ratings within the existing northern NSW network may place limitations on the maximum northerly QNI transfers. With increasing load growth in northern NSW, this may decrease the available northern transfer across QNI in future years depending on power system conditions.

The northern NSW load centres (i.e. Armidale, Tamworth and Lismore) were explicitly modelled as separate zone load traces within the market simulations. This enabled power transfers within the 330kV transmission system to be determined and incorporated within transmission constraint equations. Hence, the effects of northern NSW load growth on QNI transfer capability have fully been taken into account within the market simulations.

The limit equations used within the market simulations were based on those actually incorporated within the National Electricity Market dispatch engine. The issue of conservatism within these limit equations is thereby considered outside the scope of the study.

The installation of a second SVC at Armidale Substation was assessed as part of the range of options to upgrade QNI. However, the studies found that the optimal timing of this option was 2016/17 under the most plausible scenario (ie Scenario A - medium economic growth and realistic generator bidding behaviour), and ranked second amongst the upgrade options.

TransGrid has progressed planning considerations on both the potential to maximise the voltage control limited capability of QNI and the installation of further voltage control plant in northern NSW to meet its reliability obligations.

With respect to the existing voltage control limitations on QNI, TransGrid has recognised that there may be potential to improve the switching control of northern NSW capacitors and reactors and is examining this further. TransGrid has also consulted with NEMMCO on the potential for taking into account the impact of frequency control ancillary service arrangements in the formulation of limit equations but at this stage this does not appear to be feasible.

In terms of new voltage control plant, TransGrid has included the installation of a second SVC at Armidale as a project in its 2009-14 revenue application to the AER. This project is required to meet reliability obligations under certain scenarios of future development of the NSW system. TransGrid will commence the regulatory test assessment for this project in the near future.

Market Simulations

*A long double circuit upgraded interconnector with transfer capacity up to 1500MW can have a impact on the reliability of supply to NSW under conditions where the trip of the double circuit is declared a credible contingency. Under these circumstances this can result in a significant reduction in QNI transfer capacity which does not seem to be addressed within the Interim Report.*

Response:

The reclassification of the double circuit within QNI as a single credible contingency (as occurs from time to time due to storm activity or bushfires) has not been incorporated within the market simulations due to the low probability and duration of these events. However, TransGrid and Powerlink note that the transfer capability across QNI can be significantly reduced during these events, which could impact on market benefits associated with an interconnector upgrade.

TransGrid and Powerlink have subsequently carried out some preliminary analysis to assess the impact of reclassification events on the market benefits, and have found that incorporating these effects is unlikely to change the outcomes of the study. Nonetheless, TransGrid and Powerlink may consider modelling reclassification events and transmission forced outages within future studies.

TransGrid and Powerlink note that Option 5 - Second HVAC Interconnector does provide additional benefits associated with higher levels of system security compared to options which only increase the transfer capability of the existing interconnector. However, the study found that Option 5 was not economic due to the high capital cost of the project.

QNI Upgrade as a Funded Augmentation

*It may be possible for third parties to inject funds to top up the present values to bridge the gap to the optimum timing and bring forward the construction of the upgrade, and this is worth further investigation.*

Response:

The Rules makes provisions for the construction of funded augmentations by Transmission Network Service Providers. TransGrid and Powerlink invite prospective parties who are interested in pursuing this option to contact the organisations for further discussion.

Future Work

*We propose that TransGrid and Powerlink keep QNI upgrade high on the agenda and continue monitoring the case for an upgrade including modelling the impacts of current uncertainties such as new generation development and emission trading.*

Response:

Powerlink and TransGrid intend to continue monitoring market developments which could materially impact on the timing and scope of a potential upgrade. Further work and updates relating to an upgrade of QNI will be provided within the TransGrid and Powerlink Annual Planning Reports.

A number of observations from this exercise, such as the degree of precision around optimal timing, will provide valuable input to the anticipated AER review of the Regulatory test guidelines as an outworking of the AEMC national transmission planner review.

Powerlink and TransGrid also intend to engage with the AEMC in its recently-commissioned review of market arrangements in the light of climate change policies, as aspects of the Regulatory Test are likely to be considered.

Interested parties are encouraged to participate in those reviews.

# 10. CONCLUSIONS

TransGrid and Powerlink have carried out a comprehensive assessment of QNI upgrade options using the Australian Energy Regulator's Regulatory Test methodology. The following conclusions have been drawn from this assessment:

- The option with the highest net market benefits across a range of credible development scenarios considered is Option 1 - Series Compensation. Sensitivity testing showed the analysis is robust to variation in capital cost, cost of unserved energy and discount rate;

- The optimal timing for Option 1 - Series Compensation under Scenario A - medium economic growth and realistic generator bidding behaviour is 2015/16;

- However, the optimal timing for Option 1 - Series Compensation under the credible scenarios considered ranges from 2009/10 (high economic growth) to 2020/21 (low economic growth);

- The option that ranked second across the range of scenarios is Option 2 - Northern NSW SVC with the optimal timing about one year later than for Option 1 under the medium growth scenarios (A and D); and

- The analysis showed that the options which provided more substantial increases in transfer capability (i.e. Option 4 - HVDC Back to Back System and Option 5 - Second HVAC Connector) were not economic across the study time frame.

Based on the optimum timing for Option 1 - Series Compensation of 2015/16 under Scenario A and 2013/14 under Scenario D, and the later optimal timing for Option 2 - Northern NSW SVC, TransGrid and Powerlink consider that it is premature to recommend an augmentation option at this time.

TransGrid and Powerlink welcome the interest shown by the market within the public forums held in Brisbane and Sydney in April, and the submissions received to the Interim Report for Market Consultation. However, the two organisations consider that there are no issues raised as part of the public forums or submissions which would change the outcomes and conclusions reached within the Interim Report.

Both organisations will continue to monitor market developments which could materially impact on the timing of a potential upgrade. Triggers for conducting further analysis may include a consistent "above medium" load growth totalling 2,000MW across all regions in the NEM over several years that would indicate a high economic growth scenario is emerging, or where the optimal timing may be advanced due to the entry of as-yet uncommitted new generation scheduled for commissioning from 2012 onwards which was not included in the market modelling.

Any updates will be communicated through the TransGrid and Powerlink *Annual Planning Reports*.

# APPENDIX 1: TRANSFER CAPABILITY OF QNI UPGRADE

| Constraint ID | Description | Type | Option 1 - Series Compensation | Option 2 - SVC | Option 3 - SPS | Option 4 - HVDC | Option 5 -HVAC |
|---|---|---|---|---|---|---|---|
| **THERMAL** | | | | | | | |
| Q>N-NIL_DC and N>Q+NIL_F7 | Armidale to Tamworth 330kV | Thermal | No impact | No impact | No impact | 1500MW | +2500 |
| N>N+NIL__5 | Tamworth to Liddell 330kV | Thermal | No impact | No impact | No impact | +375 | +2500 |
| Q>N_NIL_8L_8M | Bulli Creek to Dumaresq 330kV | Thermal | No impact | No impact | No impact | +375 | +2500 |
| **STABILITY (SOUTH)** | | | | | | | |
| Q:N_B1_POT | Loss of QLD Smelter Potline | Transient | +534 | No impact | +579 | Remove | +1403 |
| Q:N_NIL_BCK2L-G | Critical Fault Bulli Creek to Dumaresq | Transient | +515 | No impact | +280 | Remove | +1386 |
| V::H_NILQA/B/C/D/E/F_BL_R | Critical Fault Sth Morang to Hazelwood | Transient | +488 | No impact | +136 | Remove | +1137 |
| Q:N_NIL_N3 | Critical Fault on Bayswater to Liddell | Transient | +310 | No impact | No impact | Remove | +865 |
| Q:N_NIL_N4 | Critical Fault on Liddell to Newcastle | Transient | +160 | No impact | No impact | Remove | +948 |
| **STABILITY (NORTH)** | | | | | | | |
| N:Q_NIL_A1 to A7 and B1 to B9 | Critical Hunter Valley Faults | Transient | +50 to +150[23] | No impact | No impact | Remove | +130 to +390[23] |
| N:Q_NIL_C1 | Loss of Callide C Unit | Transient | +240 | No impact | No impact | Remove | +624 |
| N:Q_NIL_C2 | Loss of Millmerran Unit | Transient | +240 | No impact | No impact | Remove | +624 |
| N:Q_NIL_E | Loss of Tarong North Unit | Transient | +240 | No impact | No impact | Remove | +624 |
| N:Q_NIL_F | Loss of Kogan Creek Unit | Transient | +240 | No impact | No impact | Remove | +624 |
| N^Q_NIL_A | Loss of Liddell to Muswellbrook 330kV | Voltage | +250 | No impact | No impact | Remove | +650 |
| N^Q_NIL_B | Loss of Largest QLD Generator | Voltage | +250 | Remove | No impact | Remove | +650 |

[23] The limit range is based on the two specified constraint equations

# APPENDIX 2: ECONOMIC ANALYSIS

**Scenario A** - Medium economic growth using realistic generator bidding behaviour

| Scenario A | | | QLD and NSW development - realistic bidding and medium load | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
| | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| **Option 1** | | | Series compensation | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Series compensation** | | -120 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -13.860 | -13.640 | -13.419 | -13.199 | -12.978 | -12.758 | -12.537 | -12.317 | -12.096 | -11.876 | -11.655 | -11.435 | -11.214 | -10.994 | -10.773 | -10.553 | -10.332 | -10.112 | -9.891 | -9.670 | -9.450 | -9.229 |
| ==> PV of TUOS | -$58.13 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 37.199 | 2.244 | -9.882 | 56.402 | 1.068 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 | 15.863 |
| => PV of Market Benefit (ex unserved load) | $78.85 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -26.061 | 9.615 | 17.641 | -4.306 | 3.944 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 | 5.760 |
| => PV of Unserved energy | $14.71 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total for Option 1** | **$35.43** | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -2.722 | -1.781 | -5.659 | 38.898 | -7.966 | 8.865 | 9.086 | 9.306 | 9.527 | 9.747 | 9.968 | 10.188 | 10.409 | 10.629 | 10.850 | 11.070 | 11.291 | 11.511 | 11.732 | 11.952 | 12.173 | 12.393 |
| **Option 2** | | | Northern NSW SVC | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Northern NSW SVC** | | -35.0 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -4.043 | -3.978 | -3.914 | -3.850 | -3.785 | -3.721 | -3.657 | -3.592 | -3.528 | -3.464 | -3.399 | -3.335 | -3.271 | -3.206 | -3.142 | -3.078 | -3.014 | -2.949 | -2.885 | -2.821 | -2.756 |
| ==> PV of TUOS | -$15.37 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 20.534 | 28.125 | 58.716 | -17.841 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 | 23.000 |
| => PV of Market Benefit (ex unserved load) | $98.72 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 4.376 | 12.537 | -2.801 | 3.053 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 | 4.263 |
| => PV of Unserved energy | $18.59 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total for Option 2** | **$101.94** | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20.868 | 36.68296 | 52.0017 | -18.63782 | 23.47757 | 23.54188 | 23.6062 | 23.67051 | 23.73482 | 23.79913 | 23.86345 | 23.92776 | 23.99207 | 24.05638 | 24.1207 | 24.18501 | 24.24932 | 24.31363 | 24.37795 | 24.44226 | 24.50657 |
| **Option 3** | | | System protection scheme | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **System protection scheme** | | -35.00 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -4.043 | -3.978 | -3.914 | -3.850 | -3.785 | -3.721 | -3.657 | -3.592 | -3.528 | -3.464 | -3.399 | -3.335 | -3.271 | -3.206 | -3.142 | -3.078 | -3.014 | -2.949 | -2.885 |
| ==> PV of TUOS | -$12.57 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 40.821 | -20.269 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 | 6.850 |
| => PV of Market Benefit (ex unserved load) | $26.99 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -5.475 | -2.130 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 | -2.535 |
| => PV of Unserved energy | -$9.71 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total for Option 3** | **$4.72** | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 31.304 | -26.378 | 0.402 | 0.466 | 0.530 | 0.595 | 0.659 | 0.723 | 0.788 | 0.852 | 0.916 | 0.981 | 1.045 | 1.109 | 1.173 | 1.238 | 1.302 | 1.366 | 1.431 |

## **Scenario A** - Medium economic growth using realistic generator bidding behaviour (continued)

| Option 4 – HVDC back to back | PV | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| HVDC back to back | -470.00 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 0.000 | -54.285 | -53.421 | -52.558 | -51.694 | -50.831 | -49.967 | -49.103 | -48.240 | -47.376 | -46.512 | -45.649 | -44.785 | -43.922 | -43.058 | -42.194 | -41.331 | -40.467 | -39.603 | -38.740 | -37.876 | -37.013 | -36.149 | -35.285 | -34.422 |
| ==> PV of TUOS | -$333.15 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| => Market Benefit (ex unserved load) | | 0.000 | 0.000 | 0.000 | 0.000 | 12.646 | 19.322 | 3.697 | -11.684 | 36.783 | 49.635 | -1.982 | 61.258 | 4.275 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 | 21.184 |
| => PV of Market Benefit (ex unserved load) | $135.17 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Unserved load** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| * Unserved energy benefit $ | | 0.000 | 0.000 | 0.000 | 0.000 | 2.292 | -6.536 | -5.462 | 5.256 | -25.905 | -12.754 | 13.870 | -5.041 | 0.241 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 | 3.023 |
| => PV of Unserved energy | -$7.99 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total for Option 4** | -$205.96 | 0.000 | 0.000 | 0.000 | 0.000 | -39.446 | -40.635 | -54.323 | -58.123 | -39.952 | -13.086 | -37.216 | 7.978 | -42.860 | -22.305 | -21.442 | -20.578 | -19.715 | -18.851 | -17.987 | -17.124 | -16.260 | -15.396 | -14.533 | -13.669 | -12.806 | -11.942 | -11.078 | -10.215 |

| Option 5 – Second HVAC | PV | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Second HVAC | -900.00 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| => TUOS | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -103.950 | -102.296 | -100.643 | -98.989 | -97.335 | -95.681 | -94.028 | -92.374 | -90.720 | -89.066 | -87.413 | -85.759 | -84.105 | -82.451 | -80.798 | -79.144 | -77.490 | -75.836 | -74.183 | -72.529 | -70.875 | -69.221 | -67.568 |
| ==> PV of TUOS | -$580.93 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| => Market Benefit (ex unserved load) | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 18.104 | 36.929 | 25.799 | 62.623 | 53.898 | 33.947 | 74.308 | 41.645 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 | 49.967 |
| => PV of Market Benefit (ex unserved load) | $287.95 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Unserved load** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| * Unserved energy benefit $ | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -5.198 | -0.937 | 5.047 | -4.975 | 7.080 | 11.153 | -3.343 | 5.542 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 | 4.451 |
| => PV of Unserved energy | $16.96 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total for Option 5** | -$276.02 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -91.044 | -66.304 | -69.796 | -41.341 | -36.358 | -50.581 | -23.063 | -45.186 | -36.303 | -34.649 | -32.995 | -31.341 | -29.688 | -28.034 | -26.380 | -24.726 | -23.073 | -21.419 | -19.765 | -18.111 | -16.458 | -14.804 | -13.150 |

**Scenario B** - High economic growth using realistic generator bidding behaviour

| Scenario B | | | QLD and NSW development - realistic bidding and high load | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
| | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| **Option 1** | | | **Series compensation** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Series compensation** | | -120 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | | | 0.000 | 0.000 | -13.860 | -13.640 | -13.419 | -13.199 | -12.978 | -12.758 | -12.537 | -12.317 | -12.096 | -11.876 | -11.655 | -11.435 | -11.214 | -10.994 | -10.773 | -10.553 | -10.332 | -10.112 | -9.891 | -9.670 | -9.450 | -9.229 | -9.009 | -8.788 | -8.568 | -8.347 | -8.127 | -7.906 |
| ==> PV of TUOS | -$102.32 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 27.542 | 55.140 | -2.575 | 19.296 | 23.106 | 38.278 | 29.821 | 64.941 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 | 44.347 |
| => PV of Market Benefit (ex unserved load) | $314.18 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 2.297 | -0.182 | 7.573 | 1.627 | -2.713 | -3.568 | 4.766 | 40.041 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 | 13.747 |
| => PV of Unserved energy | $76.38 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total for Option 1** | $288.23 | | 0.000 | 0.000 | 15.979 | 41.319 | -8.420 | 7.725 | 7.415 | 21.953 | 22.061 | 92.666 | 45.997 | 46.218 | 46.438 | 46.659 | 46.879 | 47.100 | 47.320 | 47.541 | 47.761 | 47.982 | 48.202 | 48.423 | 48.643 | 48.864 | 49.084 | 49.305 | 49.525 | 49.746 | 49.966 | 50.187 |
| **Option 2** | | | **Northern NSW SVC** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Northern NSW SVC** | | -35.0 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -4.043 | -3.978 | -3.914 | -3.850 | -3.785 | -3.721 | -3.657 | -3.592 | -3.528 | -3.464 | -3.399 | -3.335 | -3.271 | -3.206 | -3.142 | -3.078 | -3.014 | -2.949 | -2.885 | -2.821 | -2.756 | -2.692 | -2.628 | -2.563 |
| ==> PV of TUOS | -$20.55 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 22.420 | 40.799 | 0.396 | 37.851 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 | 26.349 |
| => PV of Market Benefit (ex unserved load) | $150.51 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 2.204 | -1.412 | -1.193 | 27.696 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 | 8.364 |
| => PV of Unserved energy | $43.90 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total for Option 2** | $173.86 | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 20.581 | 35.409 | -4.712 | 61.698 | 30.927 | 30.992 | 31.056 | 31.120 | 31.184 | 31.249 | 31.313 | 31.377 | 31.442 | 31.506 | 31.570 | 31.635 | 31.699 | 31.763 | 31.828 | 31.892 | 31.956 | 32.021 | 32.085 | 32.149 |

**Scenario C** - Low economic growth using realistic generator bidding behaviour

| Scenario C | | | QLD and NSW development - realistic bidding and low load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| **Option 1** | | | **Series compensation** | | | | | | | | | | | | | | |
| **Series compensation** | | -120 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -13.860 | -13.640 |
| ==> PV of TUOS | -$34.94 | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| => PV of Market Benefit (ex unserved load) | $0.00 | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| => PV of Unserved energy | $0.00 | | | | | | | | | | | | | | | | |
| **Total for Option 1** | -$34.94 | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -13.860 | -13.640 |
| **Option 2** | | | **Northern NSW SVC** | | | | | | | | | | | | | | |
| **Northern NSW SVC** | | -35.0 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | -4.043 | -3.978 | -3.914 | -3.850 | -3.785 | -3.721 | -3.657 | -3.592 | -3.528 | -3.464 | -3.399 | -3.335 |
| ==> PV of TUOS | -$27.22 | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | -0.128 | 0.096 | 0.225 | 0.797 | 0.942 | 1.367 | 0.679 | -4.257 | -2.451 | -7.744 | -4.818 | -4.818 |
| => PV of Market Benefit (ex unserved load) | -$16.54 | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 4.053 | -0.110 | -0.699 | 0.000 | -0.016 | 8.065 | 2.683 | 2.683 |
| => PV of Unserved energy | $11.79 | | | | | | | | | | | | | | | | |
| **Total for Option 2** | -$31.97 | | 0 | 0 | 0 | -4.17099 | -3.88191 | -3.68911 | -3.0521 | 1.209913 | -2.46331 | -3.67653 | -7.84947 | -5.9949 | -3.14326 | -5.53392 | -5.4696 |

| Scenario C | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
| | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| **Option 1** | | | | | | | | | | | | | | | |
| **Series compensation** | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | -13.419 | -13.199 | -12.978 | -12.758 | -12.537 | -12.317 | -12.096 | -11.876 | -11.655 | -11.435 | -11.214 | -10.994 | -10.773 | -10.553 | -10.332 |
| ==> PV of TUOS | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| => PV of Market Benefit (ex unserved load) | | | | | | | | | | | | | | | |
| **Unserved load** | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| => PV of Unserved energy | | | | | | | | | | | | | | | |
| **Total for Option 1** | -13.419 | -13.199 | -12.978 | -12.758 | -12.537 | -12.317 | -12.096 | -11.876 | -11.655 | -11.435 | -11.214 | -10.994 | -10.773 | -10.553 | -10.332 |
| **Option 2** | | | | | | | | | | | | | | | |
| **Northern NSW SVC** | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | -3.271 | -3.206 | -3.142 | -3.078 | -3.014 | -2.949 | -2.885 | -2.821 | -2.756 | -2.692 | -2.628 | -2.563 | -2.499 | -2.435 | -2.370 |
| ==> PV of TUOS | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 | -4.818 |
| => PV of Market Benefit (ex unserved load) | | | | | | | | | | | | | | | |
| **Unserved load** | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 | 2.683 |
| => PV of Unserved energy | | | | | | | | | | | | | | | |
| **Total for Option 2** | -5.40529 | -5.34098 | -5.27667 | -5.21236 | -5.14804 | -5.08373 | -5.01942 | -4.9551 | -4.89079 | -4.82648 | -4.76217 | -4.69786 | -4.63354 | -4.56923 | -4.50492 |

**Scenario D** - Medium economic growth using short run marginal cost (SRMC) generator bidding behaviour

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario D** | | | ***QLD and NSW development - SRMC bidding and medium load*** | | | | | | | | | | | | | | |
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| | | | **08/09** | **09/10** | **10/11** | **11/12** | **12/13** | **13/14** | **14/15** | **15/16** | **16/17** | **17/18** | **18/19** | **19/20** | **20/21** | **21/22** | **22/23** |
| **Option 1** | | | **Series compensation** | | | | | | | | | | | | | | |
| **Series compensation** | | -120 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -13.860 | -13.640 | -13.419 | -13.199 | -12.978 | -12.758 | -12.537 | -12.317 | -12.096 |
| ==> PV of TUOS | -$70.47 | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 19.691 | 27.622 | 27.585 | 68.168 | 56.322 | 29.206 | 21.670 | 35.399 | 35.399 |
| => PV of Market Benefit (ex unserved load) | $203.67 | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 26.895 | -18.345 | 4.755 | 38.106 | 53.762 | 21.663 | 11.753 | 29.059 | 29.059 |
| => PV of Unserved energy | $137.14 | | | | | | | | | | | | | | | | |
| **Total for Option 1** | **$270.34** | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 32.726 | -4.362 | 18.921 | 93.076 | 96.105 | 38.112 | 20.887 | 52.142 | 52.363 |
| **Option 2** | | | **Northern NSW SVC** | | | | | | | | | | | | | | |
| **Northern NSW SVC** | | -35.0 | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => TUOS | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -4.043 | -3.978 | -3.914 | -3.850 | -3.785 | -3.721 | -3.657 | -3.592 |
| ==> PV of TUOS | -$18.68 | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| => Market Benefit (ex unserved load) | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 27.369 | 26.342 | 65.864 | 42.703 | 47.372 | 43.986 | 44.687 | 44.687 |
| => PV of Market Benefit (ex unserved load) | $225.96 | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 08/09 | 09/10 | 10/11 | 11/12 | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 | 19/20 | 20/21 | 21/22 | 22/23 |
| * Unserved energy benefit $ | | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -18.421 | -3.629 | 11.164 | 29.888 | -34.993 | 0.010 | -1.698 | -1.698 |
| => PV of Unserved energy | -$11.79 | | | | | | | | | | | | | | | | |
| **Total for Option 2** | **$195.49** | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4.905307 | 18.7345 | 73.11352 | 68.74158 | 8.593638 | 40.27498 | 39.33202 | 39.39634 |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Scenario D** | | | | | | | | | | | | | | | | | |
| | | | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 |
| | | | **23/24** | **24/25** | **25/26** | **26/27** | **27/28** | **28/29** | **29/30** | **30/31** | **31/32** | **32/33** | **33/34** | **34/35** | **35/36** | **36/37** | **37/38** |
| **Option 1** | | | | | | | | | | | | | | | | | |
| **Series compensation** | | -120 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | | | -11.876 | -11.655 | -11.435 | -11.214 | -10.994 | -10.773 | -10.553 | -10.332 | -10.112 | -9.891 | -9.670 | -9.450 | -9.229 | -9.009 | -8.788 |
| ==> PV of TUOS | -$70.47 | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | | | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 | 35.399 |
| => PV of Market Benefit (ex unserved load) | $203.67 | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | | | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 | 29.059 |
| => PV of Unserved energy | $137.14 | | | | | | | | | | | | | | | | |
| **Total for Option 1** | **$270.34** | | 52.583 | 52.804 | 53.024 | 53.245 | 53.465 | 53.686 | 53.906 | 54.127 | 54.347 | 54.568 | 54.788 | 55.009 | 55.229 | 55.450 | 55.670 |
| **Option 2** | | | | | | | | | | | | | | | | | |
| **Northern NSW SVC** | | -35.0 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => TUOS | | | -3.528 | -3.464 | -3.399 | -3.335 | -3.271 | -3.206 | -3.142 | -3.078 | -3.014 | -2.949 | -2.885 | -2.821 | -2.756 | -2.692 | -2.628 |
| ==> PV of TUOS | -$18.68 | | | | | | | | | | | | | | | | |
| **Proposed and modelled projects** | | | | | | | | | | | | | | | | | |
| **Market benefits (ex unserved load)** | | | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| => Market Benefit (ex unserved load) | | | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 | 44.687 |
| => PV of Market Benefit (ex unserved load) | $225.96 | | | | | | | | | | | | | | | | |
| **Unserved load** | | | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 | 31/32 | 32/33 | 33/34 | 34/35 | 35/36 | 36/37 | 37/38 |
| * Unserved energy benefit $ | | | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 | -1.698 |
| => PV of Unserved energy | -$11.79 | | | | | | | | | | | | | | | | |
| **Total for Option 2** | **$195.49** | | 39.46065 | 39.52496 | 39.58927 | 39.65359 | 39.7179 | 39.78221 | 39.84652 | 39.91084 | 39.97515 | 40.03946 | 40.10377 | 40.16809 | 40.2324 | 40.29671 | 40.36102 |