MACQUARIE CAPITAL

AEMC SENE OPTIONS PAPER
REPORT TO THE GREEN GRID FORUM
DECEMBER 2010

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CONTENTS

1. EXECUTIVE SUMMARY

Assessment of AEMC SENE Options

This Report assesses the implications of the National Electricity Amendment (Scale Efficient Network Extensions 'SENE') 2010 Options Paper for potential investment in new renewable energy generation in the Eyre Peninsula in South Australia as identified in the Green Grid report (July 2010).

The Green Grid report identified potential for the development of up to an additional 2000MW of wind energy generation in the Eyre Peninsula subject to addressing transmission constraints. Establishing a market mechanism to enable financing of transmission extensions is a key step in achieving the Green Grid.

This Report assesses which of the five options outlined by the AEMC would facilitate or impede development of the Green Grid and associated investment in wind generation on the Eyre Peninsula. The five options seek to achieve a similar outcome but in a way that allocates risk differently between generators, transmission network service providers ('TNSPs') and customers.

- Option 1 uses a market based investment trigger for the SENE with regulatory oversight from the Australian Energy Regulator ('AER') and Australian Energy Market Operator ('AEMO'). The SENE is funded by generators through a proportional average charge and customers underwrite the risk of under-utilisation of the SENE asset. Option 1 introduces a cost threshold trigger such that the TNSPs would only be able to recover costs from customers once 25% of the capital costs of the investment are underwritten by firm connection agreements with generators
- Option 2 uses a similar framework as Option 1 and introduces an economic test to the proposed SENE. Option 2 removes regulated tradable access rights; leaving these to be negotiated between the TNSP and each generator
- Option 3 requires the initial connecting generators to pay the stand alone costs of its connection to the network in the absence of a scale efficient connection. Subsequent connecting generators would contribute to the stand alone cost of the first generators. The RIT-T would be applied to the incremental capacity above that required to connect the first generators, and the costs of this incremental capacity would be met by customers
- Option 4 uses the same framework as Option 3, but the incremental capacity that is funded by customers would be rebated by generators as additional generation connects
- Option 5 proposes to introduce a new type of prescribed service that is paid for by generators. Customers would still underwrite the cost of any spare capacity, but with a simplified charging framework

The following table summarises the assessment of key qualitative characteristics for each Option. These are discussed in greater detail in Section 3.1

Option	Annual SENE Charge	Financing for Generators	Project Timeline	Risks to Generators	Risks to TNSPs	Risks to Customers	Costs to Customers	Market Efficiency
Option 1	Neutral	Neutral	Neutral	Neutral / Negative [i]	Neutral	Positive	Neutral	Neutral
Option 2	Neutral	Negative	Neutral / Negative [ii]	Negative	Neutral	Positive	Neutral	Negative
Option 3	Negative	Critical Issues	Negative / Critical Issues	Critical Issues	Negative	Positive	Negative [iii]	Negative
Option 4	Negative	Critical Issues	Negative / Critical Issues	Critical Issues	Negative	Positive	Negative [iii]	Negative
Option 5	Positive	Neutral	Negative / Critical Issues	Negative	Neutral	Positive	Negative [iii]	Negative / Critical Issues [iv]

Key

Positive	■ (dark green)	Neutral	■ (light green)
Negative	■ (yellow)	Critical Issues	■ (red)

Characteristics that promote SENE development

The characteristics that would promote efficient investment in transmission assets and renewable energy generation include rules that provide parties with greater certainty over the long term SENE costs, access to the transmission network through tradable access rights, and allocation of risk to the counterparties that are best able to manage or minimise those risks.

The extent to which developers of renewable energy generation can withstand new transmission charges in the form of annual SENE payments would vary depending on the location and type of generation. This report has found that prospective wind energy generation in the Eyre Peninsula would likely be able to meet their annual payments under a SENE Options 1 or 2, but would struggle to be commercially viable under Options 3 and 4 due to the higher inherent risks involved with generators bearing stranded asset risk for the SENE. Option 5 introduces a RIT-T for the SENE; however the RIT-T may not be appropriate for a SENE asset given the issues relating to coordination, first mover risks and reduced ability of the RIT-T to incorporate strategic generation forecasts to capture market efficiencies.

Option 1 provides greatest certainty of likely costs to generators and meets the objective of capturing scale efficiencies while introducing sufficient regulatory oversight. The Option balances the need to minimise risk of asset stranding with a process that can be responsive to market preferences regarding the location and scale of network extensions. For these reasons, Option 1 would provide the most effective framework for network extensions for large scale generation opportunities such as for wind energy generation on the Eyre Peninsula.

If adopted, Option 1 would provide a much improved regulatory framework for the realisation of Green Grid.

2. BACKGROUND: GREEN GRID STUDY AND SENE RULE OPTIONS PAPER

2.1 GREEN GRID FEASIBILITY REPORT

Macquarie Capital Advisers Limited (‘Macquarie’), WorleyParsons and Baker & McKenzie prepared a report in July 2010 for RenewablesSA (the ‘Green Grid Report’) outlining the potential to develop transmission assets to unlock large scale renewable energy generation in South Australia. The Green Grid Report assessed the feasibility of a high voltage transmission network under the new Scale Efficient Network Extension (‘SENE’) Rules proposed by the Australian Energy Markets Commission (‘AEMC’) that could connect up to 2000MW of wind energy generation in the Eyre Peninsula, a region long recognised for its significant wind energy resource but constrained due to a lack of electricity transmission.

The key findings of the Green Grid Report were:

— the Eyre Peninsula offers extensive opportunities for wind generation, with four ‘wind zones’ identified as being particularly attractive. These zones experience wind speeds above 8 metres per second with the potential for over 2,000 MW of generation to be developed if appropriate transmission networks could be established

— a viable business case can exist for investment in new transmission to support large scale new generation in the Eyre Peninsula in wind zones with environmental and social conditions that are highly suitable for large scale wind farming

— there is significant investment interest from leading global wind farm developers and Australian electricity utilities who are active in the Eyre Peninsula and would be willing to develop their existing wind farm pipelines once an appropriate transmission solution is developed

— in order to realise the generation potential in the Eyre Peninsula and South Australia, augmentation would be required for the shared network and the transmission interconnectors to Victoria to allow South Australia to export electricity during periods of peak wind generation

The Green Grid business case depends on the adoption of a SENE framework to overcome drawbacks inherent in large scale transmission investment. These drawbacks include difficulties in co-ordinating commissioning timelines across multiple renewable energy projects, combining multiple connection requests into a single negotiated services agreement, lack of mechanisms available to address stranded asset risks for TNSPs and free-rider issues associated with subsequent generators connecting once the initial investment costs and risks have been borne by initial generators. The combination of these issues can result in incremental transmission development that may fail to harness efficiencies from building transmission assets at scale.

2.2 SENE RULE OPTIONS PAPER

Since the submission of the Green Grid Report, the AEMC has received feedback from interested parties regarding the proposed SENE rules and has published the National Electricity Amendment (Scale Efficient Network Extensions) Rule 2010 (the ‘AEMC Options Report’).

The AEMC Options Report combines public feedback and outlines five Rule Options for the SENE:

— Option 1 is based on the existing proposed SENE framework and introduces an investment criteria threshold such that the TNSPs would only be able to recover costs from customers once 25% of the SENE capital costs are underwritten by firm connection agreements with generators

- Option 2 uses the same framework as Option 1 and adds a requirement for the SENE to satisfy an economic test (which would not be the RIT-T) and removes the regulated tradable access rights from the proposed SENE rules. Instead of tradeable access rights, generators would need to negotiate with the TNSP for access rights in the same manner as other connection agreements on the National Electricity Market
- Option 3 requires the initial connecting generator(s) to pay the stand alone costs of their connection to the network. Any generators that subsequently connect to the SENE would contribute to the stand alone cost of the first generator(s). The RIT-T would be applied to the incremental capacity above that required to connect the first generator(s), and the costs of this incremental capacity would be met by customers
- Option 4 uses the same framework as Option 3, but the incremental capacity that passes the RIT-T which would be initially funded by customers would be rebated by payments from generators as additional generation utilises the capacity on the transmission network
- Option 5 proposes to introduce a new type of prescribed service that is regulated but paid for by generators. Customers would underwrite the cost of any spare capacity and generators would face a simplified average cost charge as outlined on page 42 of the AEMC Options Report

The AEMC is receiving feedback for the proposed options and is expected to outline the preferred SENE framework in 2011.

2.3 ASSESSMENT OF THE AEMC OPTIONS PAPER

This Report has analysed the Options outlined in the SENE Rules Options Paper and provides a high level assessment of elements likely to facilitate or impede development of the Green Grid and associated investment in wind generation on the Eyre Peninsula.

The assessment of each Option is based on a quantitative assessment of the annual SENE charge and the potential impact to equity IRRs for wind farm projects that would connect to the Green Grid; coupled with a qualitative assessment of key risks and considerations for wind farm generators, TNSPs and customers. Specifically, the Report analyses the following aspects:

- the expected forecast annual charge to developers for the proposed Green Grid project. Macquarie uses the assumptions used in the Green Grid Report[v] along with updated market assumptions and an updated assessment prepared by McLennan Magasanik Associates ('MMA') for new market benefit or RIT-T tests outlined in the Options.
- the potential ability of wind projects to obtain financing, and how this may change under each Option
- the potential ability of a generic TNSP to obtain financing
- the potential impact on the project delivery schedule and the ability of the Green Grid project to begin construction prior to 2020
- a qualitative review of risks to customers, TNSPs and generators under the proposed Options

3. ASSESSMENT OF AEMC SENE RULE OPTIONS

3.1 SENE OPTIONS SUMMARY

From the five Options discussed in the AEMC Options Paper, Option 1 is the preferred option to facilitate effective implementation of Green Grid. Option 1 is the closest to the original SENE Rule proposed by the AEMC ('Proposed SENE Rule') and provides greater certainty to potential generators on their likely annual charge and hence providing greater confidence in achieving estimated internal rates of return. This is further addressed in Section 3.2. Option 1 addresses a number of key issues that the other Options either omit or do not sufficiently address, including:

— providing a market based investment test to trigger investment in the SENE. This is a benefit over Options 3,4 and 5 that rely on a regulated investment test (such as the RIT-T) that may be less responsive to market demand

— capturing scale efficiencies by providing sufficient incentives and protections to the TNSP to build transmission assets at scale and minimise the risk of under build. This also potentially results in reducing line losses through use of higher voltage conductors. TNSPs would have an incentive to support viable SENE projects without facing stranded asset risk. In contrast, the investment test for Option 5 is very similar to existing arrangements, which have proved inflexible in capturing the benefits of scale efficiencies

— allocating risk to the counterparties that are best able to assess or manage the risks. Option 1strikes a balance of allocating the risk of stranded assets to customers while minimising the risk of this occurring. If all expected generation materialises, the cost to customers would be NPV neutral since the upfront costs associated with ramp-up would be rebated by generators who would pay slightly higher premiums than their average proportional use of the transmission line. The expected generation would be governed by robust regulatory oversight which should further protect customer interests. Moreover, the risk to customers is diversified across a broad portfolio of individual transmission assets in accordance with the application of TUOS charges. The approach in Option 1 is preferable to Options 3 and 4, which transfer stranded asset risks to the initial connecting generators. This is undesirable since Individual generators are unable to manage or adequately assess the intent or timing of competing generators. Increasing the risks generators face may result in underinvestment in generation assets which would undermine progress for establishing appropriately sized, large-scale SENE projects

— maintaining efficient locational signals for generators through the annual SENE charge that generators would pay. The tradeable access right partially mitigates the 'free rider' risk that is introduced by the connection of subsequent generators since subsequent generators would be required to compensate earlier generators if their subsequent connection constrains generators that are already connected to the SENE[vi]. These 'free rider' risks are particularly an issue with Options 3 and 4, since these Options carry significant risk for initial generators who bear the entire stranded asset risk

— providing generators with greater certainty through a flat annual charge and tradeable access rights for transmission capacity. This contrasts with Option 3 and 4, where the initial generators bear the risk of a higher SENE charge if forecast generation does not materialise, and with all the other Options which do not provide the generator with a tradeable access right thereby introducing greater revenue uncertainty

— providing sufficient regulatory oversight to protect customers who are underwriting the asset through a rigorous planning and screening process that would include AEMO, the TNSP, and the AER. The addition of the capital 25% threshold would further protect customers from stranded asset risk.

An issue that may detract from Option 1 includes the potential complexity of introducing a new type of transmission asset that has different cost recovery arrangements, investment trigger, approval and application process and the mandated access rights that are different to other transmission assets on the NEM.

Overall, Option 1 contains a number of key advantages that outweigh the potential additional complexity that a new rule change would introduce. Each Option has been assessed against the Proposed SENE Rules (the 'Base Case'). The criteria each Option has been assessed against include:

— Annual SENE charge: whether the potential SENE charge that generators face would be higher or lower than the Base Case (note – Options 3 and 4 have a high degree of variability in the annual charge due to the stranded asset risk and is assessed to negatively impact this criterion, even though Options 3 and 4 have the potential for overall lower costs if all, or nearly all, expected generation materialises)

— Financing for generators: whether generators would find it easier or more difficult to obtain debt and equity financing for projects compared to the Base Case

— Timeline: how the potential timeline may be affected by the Option. Generally, introducing additional regulatory investment tests (such as the RIT-T) to some or all of the proposed SENE may delay project timelines. The timely development of large scale renewable generation is crucial given the Australian Renewable Energy Target ('RET') and reaches its maximum renewable generation target in 2020 and the Renewable Energy Credit ('REC') expires in 2030. There is currently no guarantee that these Federal government programs will be extended beyond these periods nor that a carbon price will be introduced. Given the 20 year engineering life of wind farm assets and the considerable planning and construction times required for large scale SENE projects, requiring a RIT-T for some or all of the SENE (as required under Options 3, 4 and 5) could introduce planning delays that could impede the development of efficient large scale renewable projects

— Risks to generators: whether generators face additional risks, including stranded asset risks, revenue risks (associated with lack of regulated/tradeable access rights) and the degree of control generators have in implementing the SENE project (including which parties can influence the investment trigger and investment test, and the degree individual generators depend upon external counterparties, such as TNSPs or other generators, for a successful project) compared to the Base Case

— Risks to TNSPs: whether TNSPs face additional risks, for example, through increased counterparty risk by requiring generators to underwrite stranded asset risk compared to the Base Case

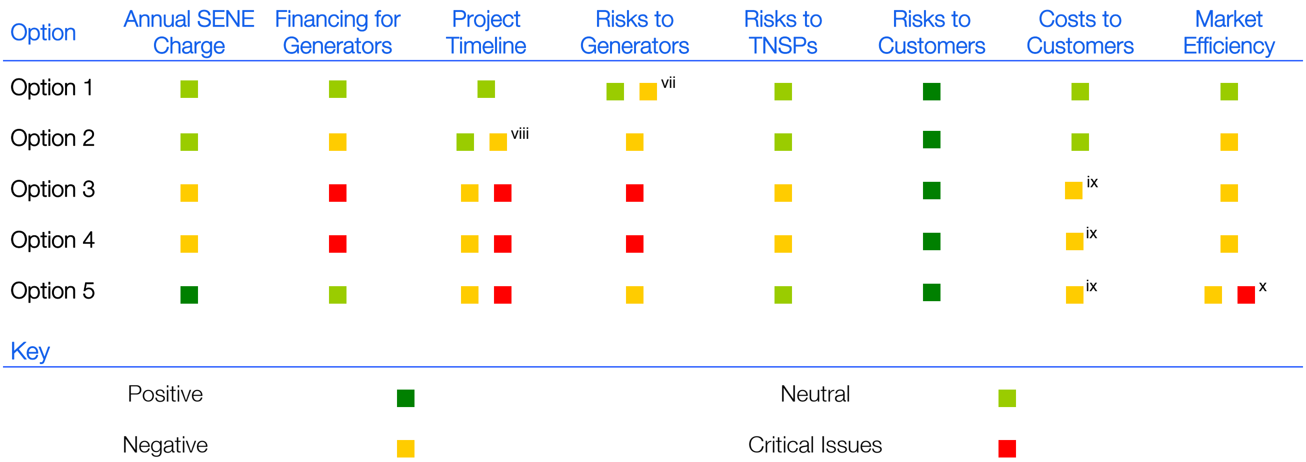
— Risks to customers: whether customers face more risk from greater potential exposure to the annual SENE charge or less risk due to increased economic investment tests or RIT-T tests compared to the Base Case. Options 1 and 2 introduce a 25% capital cost threshold as an investment trigger and Options 2 and 5 introduce an economic test and RIT-T respectively for the SENE. These features both reduce the stranded –asset risk that customers underwrite. Options 3 and 4 reduce risks to customers by transferring the stranded asset risk to generators and requiring a RIT-T for the portion of the transmission asset that exceeds the requirements of the initial generators

— Costs to customers: whether the potential exposure of the annual SENE charge customers face is higher or lower compared to the Base Case. The assessment is based on the total net present value of expected costs to customers. Options 1 and 2 are designed to be expected to be NPV neutral to customers since generators pay a SENE charge that is slightly higher than their proportional use of the SENE to reimburse customers for the amount underwritten by customers during generation ramp-up. In contrast, Options 3, 4 and 5 are designed so that the customers face positive real costs that will not be rebated by generators. Under Option 3, customers will face ongoing long term costs for the proportion of the transmission asset that satisfies the RIT-T; and under Options 3 and 4, customers do not recover the initial amounts they underwrite during the ramp-up period

— Market efficiency: whether timing or locational signals may be affected positively or negatively by the Option. For example, whether the Option introduces 'free rider' issues in timing commissioning of generation facilities, whether long term transmission access charges for the SENE distort locational signals when compared against the rest of the network, and the responsiveness of the Option to market signals and long term strategic planning requirements

Figure 1 provides an illustrative summary of the assessment of key qualitative characteristics for each Option. More detailed discussion for each Option is available in Section 4.

Figure 1 –Qualitative assessment of investment case under each AEMC Rule Options



3.2 QUANTITATIVE ASSESSMENT OF AEMC RULE OPTIONS

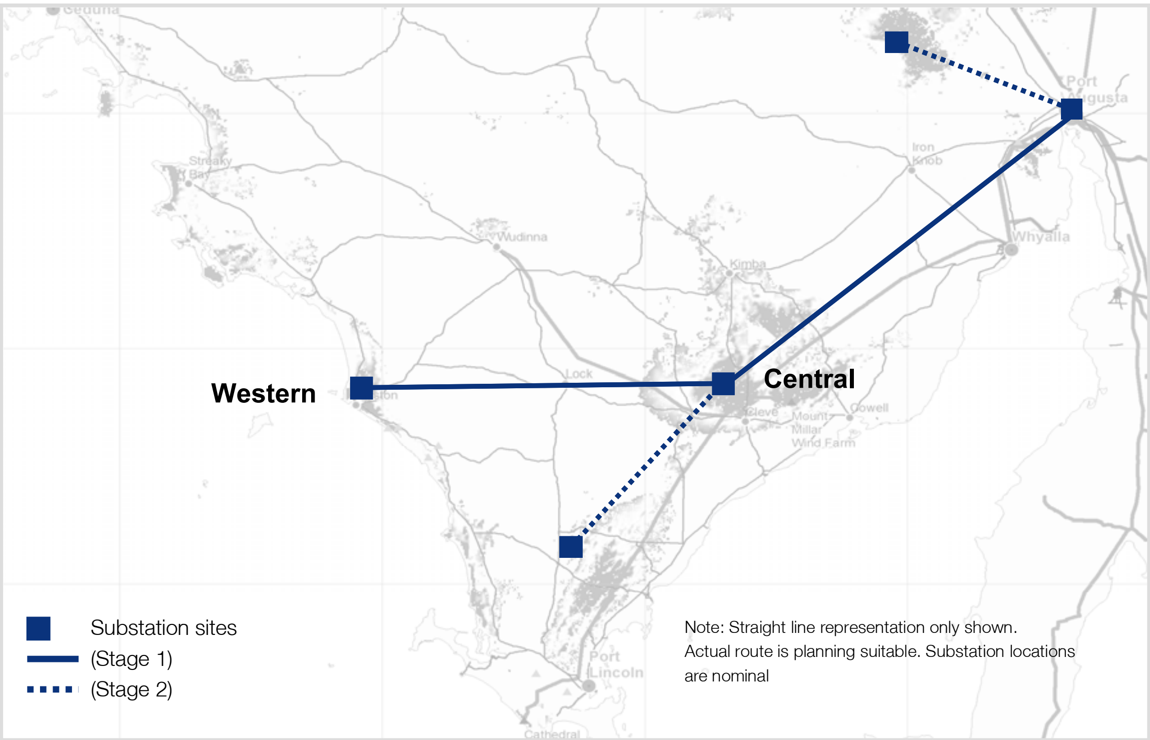
The Green Grid has been used as a framework to compare each of the Options using an example 250MW wind farm with the high yield turbines. Two areas were assessed based on potential interest for development:

— a 250MW wind farm based in Central region (the 'Central Wind Farm'), with the SENE able to cater for 1000MW of generation in the Central region

— a 250MW wind farm based in the Western region (the 'Western Wind Farm'), with the SENE able to cater for 2000MW of generation split evenly across the Central and Western regions

The Central and Western regions are indicated in the following map and are part of Stage 1 of the proposed Green Grid:

Figure 2 - Green Grid Central and Western Regions



The Options were assessed based on their potential impact to the SENE annual charge and on the expected equity IRR for potential wind farms. Overall, each of the Options has the potential to provide equity returns within a tight band of one another if all planned generation materialises. However, there is much higher uncertainty in the expected equity IRRs for initial generators under Options 3 and 4 since initial generators bear the risk of forecast generation not materialising as anticipated.

Under Options 3 and 4, the long term SENE charge may increase by 2 – 4x if additional generation does not materialise beyond the initial 250MW wind farm.

In addition, the greater revenue uncertainty arising from not having tradeable access rights (as per Options 2-5) and the increased costs associated with stranded asset risks (Options 3-4) were also factored into the quantitative assessment by introducing more stringent debt financing terms to account for the additional risk.

3.3 ANNUAL SENE CHARGE

3.3.1 SENE charge calculation methodology

The annual SENE revenue has been calculated according to the post-tax revenue model ('PTRM') used by the AER to determine the maximum allowable revenue for regulated transmission assets. This approach has been used on the basis that the SENE shares similar characteristics to regulated assets including:

— the SENE operator would be entitled to receive fixed annual revenues based upon the expected generation capacity that connects to the Green Grid

— the fixed annual SENE revenues would be underwritten by either generators or electricity customers in the event that there are shortfalls in generation capacity connected to the SENE

The revenue allowance from the SENE charge comprises a regulated return on capital, return of capital (depreciation), operating expenditure, and a tax allowance. The estimated capital and operating costs of the SENE were provided by WorleyParsons in the Green Grid Report and the financial assumptions for the weighted average cost of capital ('WACC') were compiled with reference to the prevailing market and recent regulatory decisions by Australian regulatory bodies[xi].

3.3.2 Expected SENE charge for each Option

For Options 1, 2 and 5, the annual SENE charge is assumed to be a fixed annual payment per MW of installed capacity[xii]. The charge is calculated by pro-rating the total SENE revenues for the life of the SENE asset against the forecast SENE generation profile. The business case assumes that the annual cost is based on the economic life of the transmission assets, which is estimated to be 50 years for transmission lines and sub-stations.

For Options 3 and 4, the SENE charge is dictated by the total proportion of generation that has connected to the SENE. Shortfall in generation (including during ramp-up) is covered by the connected generators and not by customers. Accordingly, the initial generators in Options 3 and 4 initially pay for the full annual SENE charge, which is proportionately rebated over time as additional generators connect.

MMA was engaged to conduct a RIT-T assessment to determine the maximum amount of transmission asset capacity that may be satisfied by the RIT-T under Option 3. Under Option 3, the incremental transmission capacity that meets the RIT-T would be funded by customers, regardless of the eventual generation profile. Under Option 4, the incremental transmission capacity initially funded by customers would be rebated by generators. If all planned generators were to connect, then the customers would no longer need to fund the incremental capacity above the initial generators requirements.

The following table displays the SENE charge per MW of installed capacity. The upside for Options 3 and 4 assumes all planned generation connects, whereas the downside assumes that no additional generation beyond the initial 250MW wind farm, i.e. that the total initial SENE charge is borne by the initial generator.

Option 3 provides the greatest scope for upside, but also faces a significant downside if no additional generation comes online. Option 4 faces similar downside risks compared to Option 3, but has a capped upside since all SENE costs would be funded by generators if all planned generation connects. Options 1, 2 and 5 are similar in terms of the expected SENE charge.

The annual SENE charge for the High Case scenarios are based on the long term SENE charge if all expected generation connects. The annual SENE charge for the Low Case scenario is based on the long term SENE charge if no additional generation connects (i.e. for Options 3 and 4, the initial SENE charge would equal the long term SENE charge in the Low Case scenario).

Table 1 – SENE Charge per MW of installed capacity

Option	Scenario	Central Region (A$ 000s)	SENE Charge as a % of Revenue[xiii]	Western Region (A$ 000s)	SENE Charge as a % of Revenue
Option 1	High Case	30.0	8.0%	30.4	8.1%
	Low Case	30.0	8.0%	30.4	8.1%
Option 2	High Case	30.0	8.0%	30.4	8.1%
	Low Case	30.0	8.0%	30.4	8.1%
Option 3	High Case	17.5	4.6%	26.7	7.1%
	Low Case	70.1	18.8%	106.7	28.5%
Option 4	High Case	29.1	7.8%	38.3	10.2%
	Low Case	70.1	18.8%	106.7	28.5%
Option 5	High Case	29.9	8.0%	29.5	7.9%
	Low Case	29.9	8.0%	29.5	7.9%

3.4 EQUITY INTERNAL RATE OF RETURN

Macquarie has used a discounted cash flow model ('DCF') to assess the potential equity returns for a 250MW wind farm in the Central and Western regions. The DCF analysis has assumed the Green Grid and the first connecting wind farm could be commissioned by 2015. This is based on consultation with the Green Grid Forum and construction timeline estimates by WorleyParsons. Macquarie notes the timeline is based on prompt introduction of the SENE rules.

3.4.1 Assumption sources

The DCF analysis incorporates technical and pricing inputs from WorleyParsons and MMA as provided in the Green Grid Report. The specific assumptions provided by each party include:

- WorleyParsons provided technical inputs including capital expenditure, operating expenditure and engineering life estimates for transmission, substation and wind turbine generator assets, development and construction costs for large scale wind farms, expected marginal and average loss factors and load growth
- MMA used the Green Grid scenario inputs to provide a forecast of wholesale electricity pool prices for the South Australian Node, REC prices and carbon prices using a CPRS -5 scenario
- Market observed inputs regarding inflation forecasts, interest rate forward curves, costs of financing, equity hurdle rates, appropriate levels of gearing and debt terms

3.4.2 Financing assumptions

- The business case assumes the wind farms have secured a long term PPA with an offtaker with an investment grade credit rating. This would greatly assist the wind farm projects in securing access to project financing
- Financing costs are based on market benchmarks for wind farm and infrastructure assets. Debt margins, establishment fees, cost of refinancing and tenors have been based on the sample Central and Western wind farms securing a PPA with an offtaker with a BBB rating or higher. The base interest rate uses the bank bill swap rate forward curve and debt margins are based on market benchmarks. Generally, financing costs have increased and gearing levels have decreased as a result of the global financial crisis. Credit spreads and margins have continued to narrow as the outlook for financing has improved in 2010. These considerations have been factored into the DCF assumptions
- The capital structure and coverage ratios have been based on a benchmarking process of recent power generation and wind farm transactions. For the Central and Western Wind Farms, the analysis has assumed gearing levels of 50-65% with a minimum debt service coverage ratio ('DSCR') of 1.45 – 1.70x. The gearing and coverage ratios have been flexed according to the inherent risks for each Option. Generally, if an Option introduces additional risks (e.g. stranded asset risks borne by generators under Options 3 and 4), the permitted gearing may decrease and the required coverage ratio may increase to reflect banks' more cautious approach
- Debt sizing and tail: the DCF analysis assumes a senior debt facility is secured which is fully amortized with a 1-2 year tail to the 15 year PPA duration. Debt is sculpted and sized according to the minimum DSCR.

3.4.3 General, technical and operating assumptions

- Inflation rate of 2.5% p.a.
- High Yield turbines with a 20 year engineering life and a turnkey capital cost of $2.5m per MW of installed capacity
- 15 year PPA with a combined REC and black electricity price at A$120 per MWh indexed to inflation[xiv], with the remaining 5 years of production sold at the prevailing spot price estimated by MMA[xv]
- An inter-temporal marginal loss factor that adjusts according to the generation ramp up, and a long term marginal loss factor of 0.91 for Central, and 0.885 for Western, Southern and Northern

- Capacity factors based on the calculations undertaken by WorleyParsons. These were calculated using the wind data supplied by Garrad Hassan and the power curves for the selected standard and high yield turbines
- An annual SENE charge based on regulated returns as calculated in Section 3.3. The SENE annual charge is payable over the life of the SENE asset, and wind farm facilities are assumed to be liable for the annual SENE charge only for as long as they are connected to the SENE

The analysis uses performance and pricing for current generation wind turbine generators. Accordingly, the analysis has not incorporated potential improvements in wind turbine technology or reduction in prices that may be observed during the potential Green Grid development between 2015 – 2020. If either of these scenarios eventuate, then the internal rate of return and the commercial viability of wind farms in the Eyre Peninsula are likely to improve.

3.4.4 Shared Network Augmentation and Interconnector Assets

ElectraNet, the South Australian TNSP and AEMO recently completed the draft 'ElectraNet – AEMO Joint Feasibility Study for the South Australian Interconnector' ('Joint Interconnector Study'). The report outlines the potential capital investments and timelines that ElectraNet may consider for an upgrade of the interconnector to Victoria.

The Joint Interconnector Study assessed a range of options, including installation of a third Heywood transformer, new Southern, Northern and Central AC lines, a Northern DC line as well as a scenario that includes the development of the Green Grid. The study investigated the net market benefits for these configurations across a number of different commissioning dates and economic scenarios.

The only scenarios that indicated a positive net market benefit were the installation of a Heywood transformer, the Southern AC line during periods of high uptake of renewable energy and the Green Grid scenario[xvi]. It should be noted that although the Green Grid scenario appears to have very high net market benefits, the authors note that this option may not have fully taken into account the losses that would arise from exporting electricity from the Green Grid in the Eyre Peninsula to Victoria.

It should also be noted that the Green Grid scenario used in the Joint Interconnector Study is not directly comparable with the findings of the Green Grid Report, since

- The Green Grid Report made the working assumption that upgrades to the shared network and interconnector would happen in conjunction with the construction and commissioning of the Green Grid. This includes commissioning the Green Grid by 2015 and connecting generators over a 5 year period to unlock to 2000MW by 2020. This network extension proposed by WorleyParsons augmented the backbone from Davenport to the Heywood interconnector, and was designed to minimise transmission losses but also maximise the use of existing transmission assets
- The Joint Feasibility Study examined 2020 and 2025 as potential commissioning dates for the shared augmentation and interconnector. One concern is that under the current REC and RET framework, commissioning dates for large scale wind farms post 2020 are unlikely, since the RET reaches its maximum renewable generation target in 2020 and the REC expires in 2030. There is currently no guarantee that these Federal government programs will be extended beyond these periods nor that a carbon price will be introduced to allow a market based mechanism to bridge the costs between thermal and renewable generation
- The Joint Interconnector Study and the Green Grid Report use different base case assumptions when assessing load demand which would affect nodal pricing and marginal loss factors

The Joint Feasibility Study assumed different forecast capital expenditure costs to those calculated by the technical adviser for the Green Grid Report. Macquarie acknowledge that it is difficult to arrive at an accurate transmission capital expenditure estimate without having conducted field surveys over the proposed route and completing a more detailed costing exercise. In order to measure the potential impact of increased capital expenditure costs in the transmission assets, this Report analyses the IRR sensitivities where capital expenditure costs for the SENE are increased by 20% and 40%. The sensitivity analysis is included in Section 0 of this Report.

3.5 INDICATIVE IRRS FOR EYRE PENINSULA WIND FARMS

This section compares the expected indicative returns for wind farms in the Central and Western regions under each Option against the required equity returns under each Option. The key results are that from an IRR perspective:

— Options 1 and 2 may result in wind farms being developed in the Central and Western regions for the Green Grid since the expected IRR may fall within the band of potential required equity IRRs

— Introduction of Option 3 or 4 is likely to result in a number of SENE assets (that would otherwise be commercially feasible under other Option frameworks) not being developed, including the Green Grid. This is a result of the combination of higher required equity returns for wind farms due to the increased transmission utilisation risks that need to be borne by wind farm generators

— Option 5 may have similar risk / return characteristics to Option 1 from the perspective of wind farm generators. However, Section 4.5 outlines reasons why a RIT-T is not appropriate for the SENE framework and how Option 5 may result in the Australian electricity market under-investing in SENE assets

It should be noted that required equity IRRs will vary according to the specific risks of each project, and the forecast IRRs will vary according to prevailing electricity and financial markets and the future costs and efficiencies of wind turbine generators.

3.5.1 Required equity returns

The required equity returns for each wind farm will depend upon the risk characteristics for each project. For greenfield wind farms these risks include the tenor and counterparty risk associated with the offtake agreement, the degree of variability in merchant pricing (for the non-contracted period of the wind farm), the protections and security package included within the turbine supply and construction agreements and operations and maintenance agreement, the reliability and track record of the turbine model and manufacturer and the availability of parent guarantees from counterparties and project sponsors.

A benchmarking exercise was conducted for wind farms and infrastructure assets. There are a wide range of contracting arrangements for wind farms and equity IRRs can be in the low teens for projects with long term availability-based offtake agreements with an investment grade counterparty, lump-sum, fixed price turnkey EPC contracts with appropriate security packages and fixed price O&M agreements with suitable performance guarantees backed by parent or bank guarantees and fixed transmission line access charges. The required IRR can increase to the high teens (or more) as one or more of these risks increase for the project.

The proposed Options carry different risk profiles for wind farm generators that connect to a SENE. The required IRR has been adjusted to account for these risk profiles:

— Option 1: Generators face a fixed annual SENE charge that is determined *a priori* and receive a tradeable access right to provide some protection against being constrained from dispatching generated electricity and a way for initial generators to exit the obligation to pay the annual SENE charge in the event that the wind farm is decommissioned prior to the end of the transmission assets' engineering life[xvii]

— Option 2: Generators face a fixed annual SENE charge, but access rights need to be negotiated directly with TNSPs. In the absence of these access rights, the risk of being constrained is increased, since there are fewer pricing signals to dissuade subsequent generators from connecting a wind farm that would constrain the initial generator. The magnitude of this increased risk depends on the specific congestion and transmission characteristics for each SENE

— Option 3: Generators face a highly variable SENE charge that depends upon the expected ramp-up profile of subsequent generators connecting to the SENE. The magnitude of this risk would depend on the proportion of initial generator capacity vis-à-vis total transmission capacity and the probability that subsequent generators would connect. Generators receive access rights consistent with the rest of the shared network

— Option 4: Generators face a highly variable SENE charge that depends upon the expected ramp-up profile of subsequent generators connecting to the SENE. Generators receive access rights consistent with the shared network

— Option 5: Generators face a fixed annual SENE charge and receive access rights consistent with the rest of the shared network

A project can be commercially viable if the expected IRR is greater than the required equity IRR for each project. Options that increase the risk to generators would increase the required IRRs and increase the likelihood that wind farm generation projects become commercially unfeasible.

3.5.2 Indicative range of IRRs

The analysis indicates that large scale wind farms that connect to the Green Grid may be developed at an IRR between 12% to 14% for High Yield turbines if all planned generation connects.

- The indicative IRR range for Options 1, 2 and 5 is between 13-14% for the Central wind farm and 12-13% for the Western wind farm. These IRRs represent a return commensurate with an asset with a long term offtake agreement and are within the range of IRRs observed from precedent wind farm generation projects[xviii]
- Options 3 and 4 have a much wider range of potential IRRs. The indicative range of IRRs is between 9.5% - 14.0% for the Central wind farm and 6.5% - 12.8% for the Western wind farm. The long tail is due to the stranded asset risk that initial connecting wind farms face under Options 3 and 4. This variability is mitigated if the initial generator(s) comprise a greater proportion of the expected generation. Generators who connect after the initial connection date would have a narrower downside range since the risk of additional generation not materializing is reduced

The following charts outline for each Option a range of potential required equity returns and a range of potential equity IRRs[xix] for a 250MW wind farm in the Central and Western regions.

Figure 3 – 250MW Central Wind Farm: Estimated potential range of IRRs

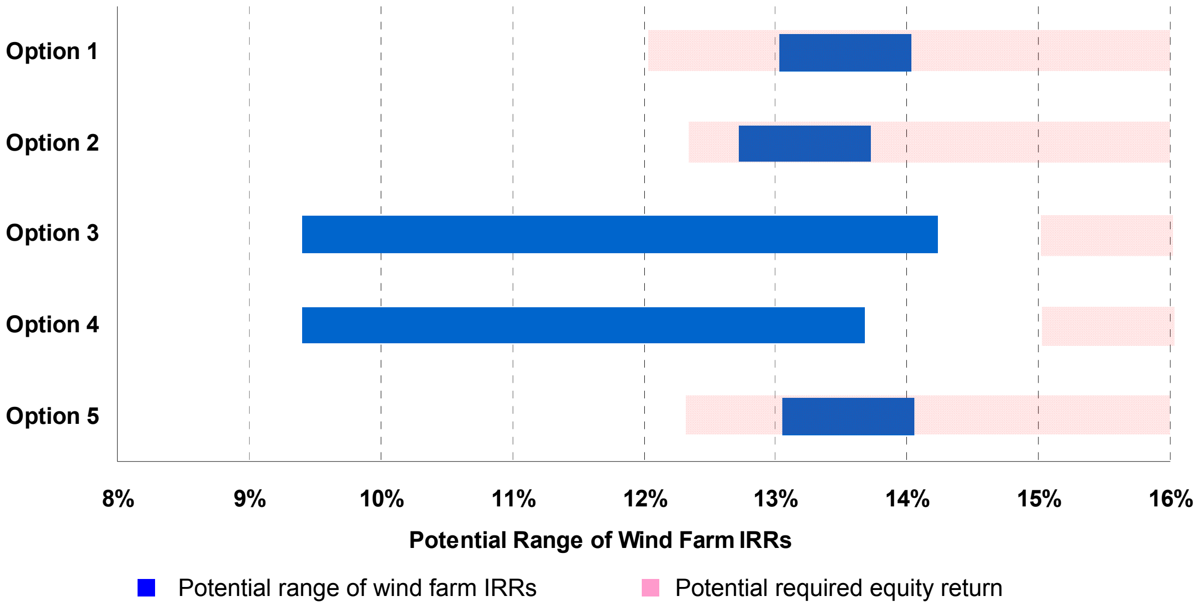
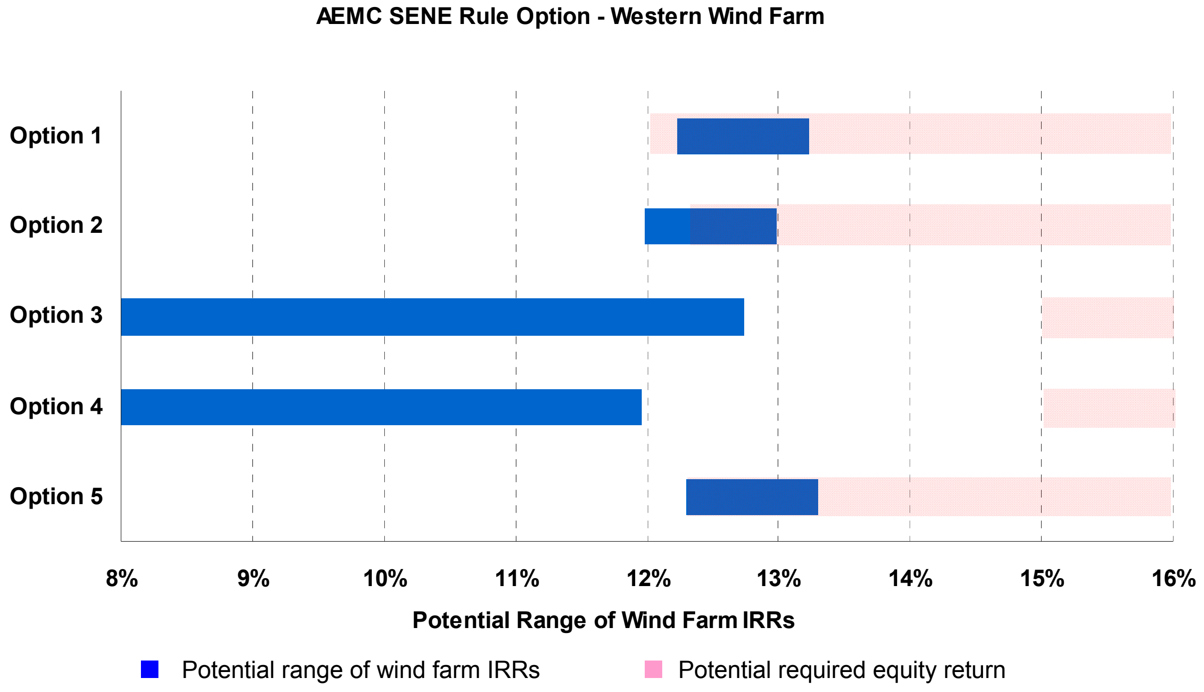


Figure 4 – 250MW Western Wind Farm: Estimated potential range of IRRs



3.6 SENSITIVITY ANALYSIS

Sensitivity analysis was completed to understand the impact on IRRs if key assumptions change. The sensitivity analysis uses a 250MW wind farm using high yield turbines in the Central region as the base case. The results are outlined in Table 2.

The key drivers of equity returns include the annual SENE charge, SENE capital expenditure cost, the wind farm's required capital expenditure, PPA price, capacity factor and marginal loss factors. Drivers that are of a second order include the wind farm operating expenditure (excluding the SENE cost), inflation and interest rates.

This analysis highlights the sensitivity of the forecast IRR to the key assumptions and the selected SENE Option Rule framework, and the importance of undertaking more detailed analysis for each specific SENE and wind farm project to decrease the level of uncertainty.

Table 2 – Central Wind Farm IRR Sensitivities

Sensitivity	IRR Delta
+ 20% SENE Charge	(0.5 – 1.0)%
- 20% SENE Charge	+ 0.5 – 1.0%
+ 40% SENE Charge	(1.0 – 2.0)%
- 40% SENE Charge	+(1.0 – 2.0)%
SENE Capex costs +20%	(0.5 – 1.0)%
SENE Capex costs +40%	(1.0 – 2.0)%
Generation ramp up profile *(changing ramp up profile from 250MW p.a. per site to 400MW, followed by three years of 200MW p.a. per site)*	+ 0.0 – 0.5%
+ 10% PPA Price	+ 2.5 – 3.0%
- 10% PPA Price	(3.5 – 4.0)%
+ 10% Electricity Generation	+ 2.5 – 3.0%
- 10% Electricity Generation	(3.5 – 4.0)%
+ 10% Wind Farm Capex Costs	(2.0 – 2.5)%
- 10% Wind Farm Capex Costs	+ 3.0 – 3.5%
+ 10% Wind Farm Opex (ex. SENE)	(1.0 – 1.5)%
- 10% Wind Farm Opex (ex. SENE)	+ 1.0 – 1.5%
+ 0.05 Wind Farm MLF	+ 1.5 – 2.0%
- 0.05 Wind Farm MLF	(1.5 – 2.0)%
+ 1% Interest rates	(0.5 – 1.0)%
- 1% Interest rates	+ 0.5 – 1.0%
+ 0.5% inflation	+ 0.5 – 1.0%
- 0.5% inflation	(0.5 – 1.0)%

4. ASSESSMENT OF INDIVIDUAL AEMC SENE OPTIONS

4.1 SENE RULE OPTION 1

Option 1 uses a similar SENE rule framework as the existing proposed SENE framework and introduces a cost threshold trigger such that the TNSPs would only be able to recover costs from customers once 25 per cent of the capital costs of the investment are underwritten by firm connection agreements with generators

From the Options presented, Option 1 is likely to be the most viable from a market based perspective whilst achieving the AEMC SENE objective to promote the efficient development of transmission assets able to mitigate market failures for large scale renewable energy generation that arise from coordination and free rider issues.

The following table outlines key differences of Option 1 against the existing proposed SENE framework (the 'Proposed SENE Rules').

Change from Initial Proposed SENE Rules

Annual SENE costs to generators	— There should be no change to the annual SENE costs compared to the Proposed SENE Rules
Generator's ability to obtain financing	— Generators are equally as likely to be able to obtain financing as long as there are sufficient assurances that the transmission assets (both the SENE and shared augmentation) would be delivered as planned for each project — Generators should have the same ability to raise debt and equity financing compared to the Proposed SENE Rules
Project delivery schedule	— There may be an additional delay until the 25% capital investment threshold is met — For the Green Grid, this risk is likely to be manageable, due to the generation interest identified for the project and the timelines proposed for the SENE process
Risks to generators	— The risk to generators would be similar to the Proposed SENE Rules
Risks to customers	— The additional 25% threshold reduces stranded asset risks for customers — Option 1 has a projected zero NPV for customers, which is the same as the Proposed SENE Rules
Risks to TNSP	— The risk of asset under-utilisation is borne by customers, so there should be no change in risks to TNSPs

4.2 SENE RULE OPTION 2

Option 2 uses a similar SENE framework as the existing Proposed SENE Rules. Option 2 introduces a 25% cost threshold trigger and also requires the application of an economic test. The proposed framework is simplified by removing the regulated tradable access rights and requiring access rights to be negotiated between the TNSP and each generator.

Option 2 is less favourable than Option 1 or the Proposed SENE Rules for three key reasons:

- Tradeable access rights provide generators with greater certainty of income as their annual proportionate payment for access to the SENE would result in their ability to dispatch generated electricity
- Lack of tradeable access rights creates 'second mover advantage' by increasing risks of 'free-riding' from generators which decide to access the SENE once it has been commissioned and once the construction, delivery and timing risks have passed. This may result in the initial generators unable to capture the full expected benefits of their investment if they are constrained
- There are insufficient incentives for TNSPs to negotiate guaranteed access rights with generators due to the open access regime currently in place. Due to a lack of transmission competition, there is likely to be an imbalance between the negotiating power between individual generators and the TNSP

The following table outlines key differences of Option 2 against the Proposed SENE Rules.

Change from Initial Proposed SENE Rules

Annual SENE costs to generators	— Negotiation of access rights is likely to increase the SENE costs to generators — If access rights are not negotiated, there should be no change to SENE charges
Generator's ability to obtain financing	— Failure to have guaranteed tradeable access rights creates uncertainty of future revenues and financiers may need to adjust their debt terms and equity hurdle rate to compensate for the increased uncertainty over access rights — This may result in reduced gearing caps and increase required debt coverage ratios to account for potential likelihood of future constraints — Expected equity returns would decrease, either through less favourable debt financing terms (if access rights are not negotiated) or through increased costs due to the negotiated access rights)
Project delivery schedule	— Depending on the timelines proposed, the economic test may extend the time required to complete SENE process; however, it may be possible for the investment test to be completed parallel to the SENE process
Risks to generators	— Initial generators face increased free rider risks and increased uncertainty of future revenues — This is important, since the set annual charge for SENEs under the Proposed SENE Rules were designed to reduce the disadvantages associated with the first mover in order for large scale transmission hubs to be developed
Risks to customers	— An economic test and a 25% cost threshold reduces stranded asset risks for customers
Risks to TNSP	— The risk of asset under-utilisation is borne by customers, so there should be no change in risks to TNSPs compared to the Proposed SENE Rules

4.3 SENE RULE OPTION 3

Option 3 requires the first generator(s) to pay the stand alone costs of its connection to the network in the absence of a scale efficient connection. Subsequent connecting generators would contribute to the stand alone cost of the first generator(s). The RIT-T would be applied to the incremental capacity above that required to connect the first generator(s), and the costs of this incremental capacity would be initially met by customers.

Option 3 is likely to significantly impede the development of SENEs except under very specialised circumstances where the initial generation assets comprise a significant majority of the total forecast capacity of the transmission asset. This is considered extremely unfavourable for the SENE rule framework since:

- The initial generator(s) would face substantial stranded asset risk that is highly likely to impede the initial generator(s) ability to obtain financing
- Option 3 effectively transfers merchant transmission asset risk onto the initial wind farm generators. Placing this risk on the initial wind farm generators is sub-optimal, since wind farm generators are unable to directly manage the inherent risks of a merchant transmission asset since they are fundamentally different to the risks of a wind farm asset. Empirically, merchant transmission assets in Australia have had very limited deployment and limited success, which suggests that scale transmission assets are better suited as regulated assets[xx]
- One of the benefits of the Proposed SENE Rules was to overcome the timing and coordination issues faced by multiple generation assets that sought connection to the same transmission line. This was overcome by allowing overbuild as long as efficient build of transmission assets at scale provided an expected NPV neutral outcome for customers. Option 3 significantly hampers this benefit by effectively requiring all initial generators to reach financial close simultaneously to eliminate stranded asset risk and allow projects to obtain reasonable financing terms

Generators may benefit from a lower annual SENE cost if all (or nearly all) planned generation materialised. However, for initial generators this benefit is overwhelmed by the increased stranded asset risk and increased difficultly in obtaining debt financing. The following table outlines key differences of Option 3 against the Proposed SENE Rules.

Change from Initial Proposed SENE Rules

Annual SENE costs to generators	— The annual SENE charge is likely to be prohibitively high for the initial generator(s) unless a significant portion connects on the initial commissioning date — The annual SENE charge may be lower than the Proposed SENE Rules if all planned generation connects and the present value of incremental proportion that would be funded by customers is greater than the present value of the additional amount funded by initial generators during ramp-up
Generator's ability to obtain financing	— Initial generators would be viewed very unfavourably by debt and equity as they bear significant stranded asset risk. The potential result is that projects may not be financeable since initial generators would be less likely to secure reasonable debt terms and higher equity returns would be required to compensate for increased risks — Option 3 requires initial generator(s) to pay the highest annual SENE costs when free cash flows to service debt would be lowest (i.e. during operational ramp up)
Project delivery schedule	— Likely delays due to the significant timing/coordination problems and the RIT-T assessment required to assess the incremental transmission capacity
Risks to generators	— Initial generator(s) face higher risks associated with the stranded asset risk

	— There would be no first mover advantage; in fact, last mover advantage is conferred due to the introduction of significant free rider risks
Risks to customers	— Customers face lower risk as they do not bear stranded asset risk — Customers could face potentially higher costs if all planned generation connects
Risks to TNSP	— TNSPs face higher risk, due to higher potential default risk of initial generator(s) if planned generation does not materialise

4.4 SENE RULE OPTION 4

Option 4 is the same as Option 3, but the incremental capacity that is funded by customers would be rebated as additional generation connects.

Option 4 is considered unworkable for the majority of potential SENE projects and is considered to be the least favoured SENE framework from a market perspective. Option 4 has the same considerations as Option 3, but removes the potential benefit of a lower annual SENE charge that generators would receive if all (or nearly all) planned generation connects.

The following table outlines key differences of Option 4 against the Proposed SENE Rules.

Change from Initial Proposed SENE Rules

Annual SENE costs to generators	— The annual SENE charge is likely to be prohibitively high for the initial generator(s) unless a significant portion connects on the initial commissioning date — The annual SENE charge would be higher than the SENE costs in Option 3, and would only approximate the costs in the Proposed SENE Rules if all planned generation connects

Generator's ability to obtain financing	— Initial generators would be viewed very unfavourably by debt and equity as they bear significant stranded asset risk. The likely result is that many projects would not be financeable since:
	  — initial generators would be unlikely to secure reasonable debt financing
	  — higher equity returns would be required to compensate investors for the increased risks
	— Option 4 results in the initial generator(s) being required to pay the highest annual SENE costs when free cash flows to service debt would be the lowest (i.e. during operational ramp up)

Project delivery schedule	— Likely delays due to the significant timing/coordination problem and the RIT-T assessment required to assess the incremental capacity that can be funded by customers
Risks to generators	— Initial generator(s) face higher risks associated with the stranded asset risk — There would be no first mover advantage; in fact, last mover advantage is conferred due to the introduction of significant free rider risks
Risks to customers	— Customers face lower risk as they do not bear stranded asset risk
Risks to TNSP	— TNSPs face higher risk, due to higher potential default risk of initial generator(s) if planned generation does not materialise

4.5 SENE RULE OPTION 5

Option 5 proposes to introduce a new type of prescribed service that is paid for by generators. Customers would still underwrite the cost of any spare capacity, but with a simplified charging framework.

The key risk for Option 5 is that potential projects may be delayed or not built either due to the longer lead times of a RIT-T process or due to anticipation that project economics may be improved if TUOS charges were applied instead of SENE charges. There are a number of reasons why the RIT-T is not necessarily suitable for the SENE framework, including:

- **Project delivery timelines using the RIT-T vs. market based mechanisms:** A key aspect of the Proposed SENE Rules is to address the issues associated with build-out of incremental capacity on transmission networks using the RIT-T. The RIT-T process is likely to take additional time and face additional feasibility costs when compared to a market based approach
  - The impact of timing delays is especially crucial under the existing RET and REC framework. The RET target of 41,000GWh will plateau in 2020 and the REC scheme will expire by 2030. Given there is no guarantee of extension of the REC scheme or the introduction of a sufficient carbon signal, the debt market would only lend to projects based upon existing schemes
  - The window of opportunity to develop large scale assets would need to fit within these RET and REC timeframes. Given the 20 year engineering life of wind farm assets and the considerable planning and construction times required for large scale SENE projects, any planning delays could significantly impede the development of efficient large scale renewable projects
- **Efficient market response:** A market based system is expected to provide more efficient and responsive investment signals when compared to the RIT-T, specifically:
  - The RIT-T currently does not have a mechanism to take into account scale benefits that would arise from anticipated forecast generation, which the SENE framework aims to address
  - The RIT-T does not adequately address co-ordination of generators or first mover issues that are among the key reasons for the introduction of a SENE framework
  - The SENE framework still promotes market behaviour that is economically rational. Generators, AEMO and TNSPs would still need to factor in locational signals such as forecast pool prices, load growth, congestion, loss factors and available renewable energy resources
  - The RIT-T was designed to rank individual projects to meet a specific goal of meeting electricity load requirements base on the least cost alternative. In the absence of capital restrictions, projects that have a positive NPV should be pursued by market participants. The SENE framework allows the market to assess which projects have an expected positive NPV and which should be pursued. Requiring the use of the RIT-T for assets that would largely be funded by generators may result in financially viable projects not being developed
- **Suitability of the RIT-T for the SENE Framework:** The RIT-T requires review of a range of alternative options which is difficult to achieve given the broad range of potential options that could potentially be considered. For SENE scenarios with a large range of alternatives, the RIT-T could potentially introduce an unworkable degree of additional complexity. Under such a scenario, a RIT-T assessing all alternatives would increase the risk of compounding incremental errors from relying on a large number of assumptions required to make detailed centralised assessments

— **TUOS Charge vs. SENE Charge:** Option 5 may result in generators delaying applications for a SENE if there is the chance that the TNSP may determine the transmission asset could satisfy a RIT-T and result in TUOS charges being recovered from customers instead of SENE charges being recovered from generators. The RIT-T is an appropriate mechanism for assets that are wholly funded by customers, but not for SENE assets that are largely funded by generators

The following table outlines key differences of Option 5 against the Proposed SENE Rules.

Change from Initial Proposed SENE Rules

SENE Annual Costs and Equity Internal Rate of Return	— The annual SENE charge would be lower than the Proposed SENE Rules, since generators pay for the simplified average proportional cost. The magnitude in savings depends on the expected commissioning profile — Given the asset passed RIT-T, generators would prefer TUOS to be applied to recover costs from customers
Generator's ability to obtain financing	— Projects should receive slightly higher returns than the Proposed SENE Rules since the annual SENE cost should be lower — The required equity IRR may be slightly higher due to lack of firm access rights
Project Delivery Schedule	— Requiring the RIT-T for the entire SENE may delay the process
Risks to Generators	— Generators face the same risks as the Proposed SENE Rules
Risks to Customers	— Higher total cost to customers, as they fund initial ramp up period, but don't recover costs once all generation connects
Risks to TNSP	— TNSPs face the same risks as the Proposed SENE Rules

5. ABILITY OF TRANSMISSION NETWORK SERVICE PROVIDER TO OBTAIN FINANCING

5.1 SOURCES OF FUNDING

The Options outlined in the Options Paper permit TNSPs to recover annual SENE charges from generators and customers. The specific cost recovery mechanism changes according to each Option, but the general premise for all Options is that the primary cost of the SENE would be recovered from the generators that connect to the SENE. Augmentations to the shared network that satisfy the RIT-T would be a prescribed transmission asset that would form part of the TNSPs regulated asset base.

The most likely candidates to establish SENEs are incumbent TNSPs. Although it is possible for new entrants to develop SENE assets[xxi], incumbent TNSPs have a natural advantage since transmission networks exhibit significant positive economies of scale, high entry costs and TNSPs have significant operating expertise and control over the broader network.

There are no restrictions to the size of a SENE, as long as the investment test of the Option is satisfied. Smaller SENE assets may be funded from retained earnings generated by the TNSP. For larger SENE projects, external funding may be required, which may be obtained from a range of sources including:

— Government funding: Government owned TNSPs may seek additional funding from their respective government sponsors. This may cover some or all of the required SENE capital expenditure costs

— Corporate bank debt: existing and new debt facilities may be used to fund SENE capital expenditure. Senior bank debt has the benefit of generally being the lowest cost funding source for TNSPs, but may not be a preferred route for some government owned TNSPs. The specific volume of additional bank debt available for each TNSP will depend on its gearing, cash flow coverage end existing debt covenants, and pricing would be based on the seniority of the new debt, debt tenor and TNSP credit rating

— Corporate bond issuance: TNSPs can issue corporate bonds into both domestic and offshore debt capital markets. Offshore capital markets such as the US144A market provide an additional source of funding to domestic markets due to the prevailing US base rate and level of available liquidity. Recent precedents include ElectraNet raising US$350m in the US144A market across two equal 4 and 6 year tranches in April 2008[xxii]

— Ordinary equity: TNSPs can raise additional ordinary equity to maintain or improve their targeted gearing and credit metrics. The cost and availability of additional equity would vary according to each TNSP[xxiii]

— Project finance debt and equity: if a TNSP wanted to ring-fence the SENE asset or if additional third party equity were required to fund a SENE, a project finance structure can be created by establishing a special purpose vehicle and using the cashflow stream to raise non-recourse debt. This project finance structure would allow both the TNSP and other third party sponsors direct exposure to the SENE. This structure is reliant upon certainty of cashflows for the project vehicle, since financiers would not have recourse against the TNSPs other assets. Options 1, 2 and 5 are more amenable to project finance structures since any shortfall in generation would result in customers underwriting the revenue for the TNSP. The project finance structure is more difficult for Options 3 and 4, since banks would rely upon the solvency of the initial generators if no additional generation connects. This increases the counterparty risk faced by TNSPs. This may be mitigated if the initial connecting generator provides a parent guarantee that is backed by a strong balance sheet; however this would not necessarily apply in all circumstances

5.2 OPTIONS ASSESMENT ON ABILITY OF TNSP TO RAISE FINANCING

The different Options change the risk profile and certainty of cashflows for TNSPs. SENEs funded by the balance sheet of the TNSP would be one of a portfolio of transmission assets held by the TNSP. Since the cost and availability of corporate finance for a TNSP will depend on their total asset portfolio, the impact of a single SENE on the TNSP's overall ability to raise financing will depend on the relative size of the SENE compared with the overall size of the TNSP's assets.

For TNSPs that aim to raise project finance for an individual SENE asset, the project specific risk profile and certainty of cashflows for the SENE will directly impact the ability of the project to secure favourable financing terms.

The impact of the Options on the risk profile for a potential SENE largely depends upon the extent TNSPs are exposed to the counterparty risk from generators, and whether TNSPs can recover the SENE annual charge from customers in the event that a generator defaults. The following analysis assumes that if a generator defaults, then TNSPs would not be able to recover the full annual SENE charge from customers[xxiv]:

- Option 1: Cost recovery for the SENE is through a proportional average charge to generators with customers underwriting the residual transmission capacity for generators that have not connected to the SENE. TNSPs face counterparty risk for the generators that have connected, but do not face direct stranded asset risk since they receive a regulated return from customers who underwrite the risk anticipated generation does not materialise
- Option 2: Cost recovery for the SENE is the same as Option 1. Generators are required to negotiate access rights with the TNSP, providing a greater degree of control to the TNSP
- Option 3: The initial generators are required to fund the annual SENE costs until additional generators connect. Customers fund the proportion of the SENE that exceeds the initial generator(s) requirements that pass the RIT-T. TNSPs face greater counterparty risk due to a greater proportion of the initial SENE costs during ramp-up being funded by the initial generator(s). TNSP's face higher indirect stranded asset risk since the initial generator would face higher risk of financial distress if planned generation does not materialise
- Option 4: Initial cost recovery for the SENE is the same as Option 3. As subsequent generators connect, the proportion of the annual SENE charge that is initially funded by customers would be rebated by the additional generators. If all planned generation connects, then the full annual SENE charge would be funded by generators. Option 4 results in the highest risk to TNSPs since it exposes them to the greatest counterparty risk from generators
- Option 5: Cost recovery for the SENE is through a simplified average charge to generators with customers underwriting the risk of anticipated generation not materialising. The risk to TNSPs is marginally lower under Option 5 under the base case, since generators would bear a slightly smaller proportion of total overall SENE costs compared to Option 1. This is because Option 5 charges generators a simplified annual SENE charge that does not seek to refund customers for the value of the SENE charge customers have paid during the ramp-up phase

Options 1, 2 and 5 are likely to be preferred from the perspective of a TNSP's ability to raise financing on reasonable terms. These Options reduce the annual SENE charge to be recovered from generators and increases the proportion of the charge payable by customers through the regulated TUOS hence reducing overall counterparty risk.

5.3 ASSESSING THE RISK PROFILE OF SENE ASSETS

SENEs with quasi-regulated returns are likely to provide investors with a with a risk/return profile that would attract investors with lower costs of capital that seek more stable, lower risk returns. This return profile would meet requirements for equity investors that are seeking 'bond like' returns from long term investments in 'core' infrastructure assets. These include investors such as pension funds, insurance funds and asset managers that manage yield based funds.

The following table outlines the risk and return parameters for a regulated transmission asset.

Table 3 – Risk profile of regulated transmission assets

Risk	Description
Volume risk: Low	This is a heavily regulated industry where the AER sets an allowed regulated revenue stream for TNSPs based on an allowed return on capital which are reviewed every five years. Overall, the volume risk is very limited. During the five year arrangement, there is a small risk that the actual volume is not as high as assumed, however providers generally see this as an opportunity to make short-term gains through under-estimating volumes rather than risk. Where there is a large divergence between assumed and actual volumes, the AER takes this into account during the reset and adjust the allowed regulated revenue for the next period accordingly.
Price risk: Low	As the AER sets an allowed revenue stream for the life of the SENE asset, price risk is very limited. During the initial five year arrangement there is no price risk, however there is some risk that during reset dates, the AER adjusts inputs (such as asset betas) for calculating the allowed return. This may create a difference between the SENE returns and the maximum allowable revenue for other regulated assets.
Regulatory / Change of Law risk: Low to Medium	This is a fully regulated asset class and is subject to regulatory risk. However, the regulatory environment in Australia is seen as stable and there are periodic reviews where industry input has been welcomed. Note that a change in law could have material impact on valuation.
Operating cost risk: Low	Operating costs are generally small as most TNSPs have high EBITDA margins and operating costs are taken into account in the allowed return calculation. However, there is a small risk that actual operating costs differ from forecast.
Capex risk: Low to Medium	Capex costs are significant although known well in advance and taken into account in the regulated return allowance. It consists mainly of maintenance capex although growth capex can be material if looking to expand to new areas. There is a small risk that the capex costs differ from those assumed in the regulated return allowance.
Competition risk: Low	These assets are natural monopolies and hence heavily regulated. There is generally no competition risk as their capital intensive nature means that it would not be in government interest to duplicate.
Customer / sub-contractor risk: Low	There is limited customer risk due to switching since the network is a local monopoly.

6. ABILITY OF WIND FARM GENERATOR TO OBTAIN FINANCING

6.1 SOURCES OF FUNDING

Wind Farm projects may be funded through the balance sheet of various entities including electricity utilities or infrastructure funds that own portfolios of generator assets. Alternatively, wind farm investment can be structured through a project finance structure utilising a special purpose vehicle ('SPV') if the owners wish to ring fence the asset or permit third parties with direct investment opportunities in the asset. The sources of funding available to wind farm owners include corporate debt through bank debt at the project SPV or parent level, corporate bond issuance at the parent level and equity issuance at the project SPV or parent level.

Generally, renewable energy plants have a higher risk profile compared to regulated or semi-regulated utility assets, so the required financing package is likely to have stricter covenants and equity investors may require a higher return to compensate them for the additional risks.

There is current appetite in the market from both the debt and equity investors to participate in renewable energy projects with strong project fundamentals. Potential equity investors include infrastructure funds, pension funds, strategic investors such as electricity utilities and independent power producers. Potential debt investors include domestic and foreign lenders and are discussed in greater detail in Section 7.

6.2 OPTIONS ASSESMENT ON ABILITY OF GENERATOR TO RAISE FINANCING

The different SENE Rule Options change the risk profile, costs and certainty of cashflows faced by generators. The main difference is due to changes in the potential annual SENE charge that generators may face.

Options 1, 2 and 5 provide greater certainty of cashflows and lower project delivery risks since the annual charge would be fixed and determined prior to financial close. Options 3 and 4 increase the variability of annual SENE costs for any generator that is not the last generator to connect. This is because the initial generators bear the stranded asset risk for the SENE instead of customers. The additional risks and costs under Options 3 and 4 negatively impact on generators' ability to raise financing for wind farms connecting to SENEs.

Option 1:

Generators face the lowest project risks under Option 1 which represents the Option with the highest likelihood for generators to secure debt and equity financing.

— Generators face a fixed annual SENE charge that reflects the proportional average transmission capacity the generator would utilise. Customers would underwrite the residual transmission capacity during the ramp up phase, and the annual SENE charge to generators would be calculated to ensure customers are NPV neutral over the life of the transmission asset.

— Generators receive a tradeable access right that provides some revenue protection by dissuading subsequent generators from connecting if the subsequent generation would cause constraints in the SENE asset. In addition, initial generators would be compensated if subsequent generation that connects to the SENE constrains the initial generators.

— The introduction of the 25% cost threshold may introduce project delivery risk if more than one generator is required. This would increase the complexity due to required coordination issues and introduces the possibility of projects not proceeding or being delayed if one or more of the initial generators is unable to provide firm commitments that would provide TNSPs with sufficient certainty to proceed with the SENE.

Option 2:

Option 2 exposes generators to greater risks compared to Option1, but still provides a reasonable opportunity for generators to raise debt and equity investment.

- The annual SENE charge to generators is the same as option 1, however there is increased risk of project delays if the required economic test can not be run in parallel to the SENE process
- Generators are required to negotiate access rights with the TNSP. This increases the risks associated with congestion on the SENE from subsequent generators that connect. This reduces future potential revenue certainty that debt and equity investors would need to factor in their investment decision

The slightly higher overall risk has been factored into the required equity returns and financing terms. The expected congestion would vary for each project and has not been explicitly quantified.

Option 3:

Generators face significantly higher risks compared to Options 1, 2 and 5. The magnitude of this increased risk depends upon the proportion of the total generation capacity is committed to by the initial generators. A higher volume of initial generation installed capacity would reduce stranded asset risks.

The increased cashflow uncertainty is likely to result in less favourable financing terms for the project. Debt investors are likely to require more stringent debt covenants, lower gearing caps and higher coverage ratios. This, coupled with the higher SENE charges, would reduce the available free cash flows and may reduce overall project IRRs. Equity investors are likely to require a higher IRR in order to compensate them for the additional risks.

The result is that projects are likely to have higher equity return hurdle and a lower expected IRR, which decreases the likelihood that a project would be commercially feasible and be able to raise sufficient debt and equity financing.

The specific considerations for Option 3 are:

- The initial generators are required to fund the annual SENE costs until additional generators connect. Customers fund the proportion of the SENE that exceeds the initial generator(s) requirements that pass the RIT-T
- Generators bear the stranded asset risk if anticipated generation does not materialise. Under the Green Grid scenario, this could result in the long term annual SENE charge being up to 4x higher than the scenario where all generation commits
- Generators do not receive a tradable access right, and hence face higher risks from congestion on the SENE asset
- Initial generator(s) are required to pay the highest annual SENE costs when free cash flows to service debt would be the lowest (i.e. during operational ramp up)
- It should be noted that if all planned generation connects, then generators may pay a lower long term annual charge. This would occur if the present value of the proportion of the SENE that passes the RIT-T and continues to be funded by customers is greater than the present value of the increased upfront costs generators would need to fund during ramp-up. This potential benefit would be overshadowed by the increased risk associated with Option 3

Option 4

Generators face significantly higher risks compared to Options 1, 2 and 5. Option 4 has effectively the same risks outlined above for Option 3

Generators face higher long term Annual SENE charges compared to Option 3 because as subsequent generators connect, the proportion of the annual SENE charge that is initially funded by customers would be rebated by the generators. If all planned generation connects, then the full annual SENE charge would be funded by generators.

The result is that projects are likely to have lower expected IRRs than Option 3, which further decreases the likelihood that a project would be commercially feasible and be able to raise sufficient debt and equity financing.

Option 5:

Cost recovery for the SENE is through a simplified average charge to generators with customers underwriting the risk of anticipated generation not materialising. This approach can allow generators to raise debt and equity investment, since the annual charge is well defined at the beginning of the project and not subject to stranded asset risk.

The key risks to generators under Option 5 are lengthening project delivery timelines and the possibility that projects that would otherwise be commercially viable are not pursued because of the requirement to satisfy a RIT-T that is not suited for a SENE framework.

6.3 ASSESSING THE RISK PROFILE OF WIND FARMS

The viability of wind farm development in the Eyre Peninsula will depend on each project's equity IRRs. Specifically, the equity IRR for each project needs to be sufficient to appropriately reward investors for the investment risks they undertake. The key risks and mitigants for wind farm generation facilities are outlined in the following table.

Table 3 – Risk profile of wind farm assets

Risk	Description
Volume and Price Risk	Wind farm volume is measured on an annual basis and wind farm capacity factors / output can be difficult to forecast. There is a risk that the contracted volumes are materially lower than capacity. Volume and price risks can be mitigated through different offtake structures. Offtake arrangements can include purchase of the RECs, black energy or both. Potential offtake structures can include:
Low	— Availability or capacity payment structures which ensure the project receives revenues as long as the facility continues to operate according to a pre-agreed level of availability. This ensures project sponsors are insulated from price and volume risks and is likely to require the lowest equity IRR requirements
Low to Medium	— 'Take or Pay' arrangements where the offtaker purchases the amount of electricity produced at a pre-agreed price. Accordingly the project sponsors will take 'wind risk' or 'volume risk' but are insulated from pricing risk. This PPA structure will have a higher equity IRR requirement compared to availability payments
Medium to High	— Merchant wind farms where there is no long term PPA, and the wind farm sells the amount of electricity it produces on the spot market. This would require the project to deliver a higher equity IRR and incur higher debt margins due to the higher risks associated with the revenue stream. In addition, if the term of the offtake contract is less than the life of the asset, then there would be volume and price risk upon if the expired contract is not renewed
Regulatory / Change of Law risk: Low to medium	There is limited regulatory risk. However, change in law can have a material impact e.g. LRET and CPRS, but is typically mitigated by the long term contracts.
Operating cost risk: Medium	Wind farms are a low operating cost / high margin business where operations are fairly simple. Performance and availability guarantees can be sought from turbine suppliers in order to minimise risks associated with wind turbine performance. In addition, significant operating cost risks and

Risk	Description
	turbine damage should be covered by an appropriate insurance policy.
Construction Risk: Low to medium	Design and construction contracts can be mitigated by engaging credible construction partners with a strong track record in delivery. Securing a fixed price, lump sum turnkey engineering, procurement and construction contract with appropriate performance bonds and guarantees would limit risks in construction costs.
Capex risk: Low to Medium	Minimal cyclical maintenance capex post construction, along with some one-off event risk which would generally be covered by insurance.
Competition risk: Low to Medium	There is a degree of technology risk based on the cost and location of geothermal, photovoltaic and other renewable energy technologies. Largely dependent on contract terms and in any event given the low operating cost / high margin nature of the business, existing wind farms are generally expected to continue to operate regardless. There is a risk that if a competitor enters the market nearby and shares the same transmission lines, electricity loss factors may increase. In addition, there is a risk that the contract is not renewed post expiration due to the development of new wind farms.
Customer / sub-contractor risk: Low to Medium	The PPA should be sourced from counterparties with strong credit ratings to provide equity investors with comfort that the PPA obligations would be met for the duration of the PPA. In the South Australian market, there is limited diversification of customers, with AGL and Origin being the likely candidates to provide a long term bankable PPA.
Financial risk: Medium	Depending upon the terms of the contract, leverage is typically medium to high.

7. SOURCES OF FUNDING

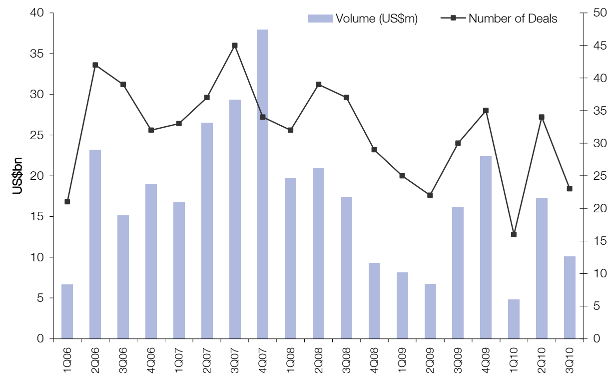
There are a range of funding sources available for TNSPs and wind farm generators. This includes corporate bank debt, bond issuances on capital markets and project finance debt and equity. The availability and potential costs for these funding sources are outlined in the following sections.

7.1 CORPORATE BANK DEBT

The Australian infrastructure debt market is expected to remain stable in the mid-term and grow from 2012 to 2015 due to upcoming maturities and investment / divestment by government. Domestic and foreign banks are showing renewed appetite for infrastructure transactions with domestic banks taking increasingly larger holds.

Banks are demonstrating increased capacity for take-and-hold levels with some willingness to underwrite debt. Strong investment grade borrowers such as utilities with good credit ratings are expected to be able to tighten pricing. Importantly, there has been a rebound in bank market volume and deals in the latter half of 2010.

Figure 5 - Australian corporate quarterly loan volume



Source: LoanConnector, Dealogic

The following table outlines recently closed corporate bank debt facilities for Australian energy utilities. The weighted average debt margin for the comparable transactions within the last 12 months is approximately 244 basis points over the bank bill swap rate ('BBSY'). Furthermore, there are indications that margins will continue to narrow from the peaks experienced during the global financial crisis as confidence and liquidity returns to the debt market.

Credit Date	Borrower	Deal Currency	Deal Amount (m)	Tranche Currency	Tranche Amount (m)	Tenor	Margin over BBSY (bps)
7 Apr 10	Origin Energy Ltd (Baa1/BBB+)	AUD	2,516	AUD	225	3	185
				AUD	375	5	230
				AUD	400	3	185
				AUD	1,300	5	230
				USD	200	5	230
22 Dec 09	Alinta energy (ex-BBP Finance Australia Pty Ltd)	AUD	2,800	AUD	1,600	3	245[xxv]
				AUD	960	3	n/a
				AUD	100	3	n/a
				AUD	60	3	n/a
				AUD	80	3	n/a
22 Sep 09	CitiPower I Pty Ltd	AUD	175	AUD	175	3	n/a
17 Aug 09	TRUenergy Pty Ltd (BBB-)	AUD	350	AUD	350		340
20 Jul 09	ElectraNet Pty Ltd (Baa1/BBB)	AUD	200	AUD	200		n/a

Credit Date	Borrower	Deal Currency	Deal Amount (m)	Tranche Currency	Tranche Amount (m)	Tenor	Margin over BBSY (bps)
5 Jun 09	AGL Energy Ltd (NR/BBB)	AUD	800	AUD	600		280
				AUD	200		280
May/Jun 09	SPAusNet (A1 Moodys / A- S&P)	AUD	325	AUD	275	3	250
				AUD	50	3	250

7.2 DEBT CAPITAL MARKETS

Companies may access debt capital markets by issuing bonds in the domestic or foreign capital markets. Individual wind or SENE projects are less likely to access the bond market given the smaller size of debt required for an individual project, and the higher costs and complexity associated with a bond issue compared to securing senior bank debt.

7.2.1 Domestic capital markets

There is strong domestic institutional demand for quality corporate bonds. There are indications that corporate bond spreads are beginning to narrow. Corporate bond spreads were 320-350bps in 2009 and are closer to 250-270bps in Q2 2010, despite recent concerns over the European debt markets. Strong domestic institutional demand for quality corporate bonds, albeit on low volume

Figure 6 – Australian Corporate Bond Spreads

Source: Dealogic, Bloomberg, LoanConnector

Figure 7 – Australian Annual Corporate Bond Volume

Source: Dealogic, Bloomberg, LoanConnector

The following table lists recent domestic corporate bond issuance. The weighted average spread for comparable transactions with a BBB credit rating within the last 12 months is approximately 272 basis points over BBSW.

Issuer	Date	Currency	Amt ($m)	Tenor (Yrs)	Spread to Benchmark (bps)
DBNGP (Baa3/BBB-)	Sep-10	AUD	550	5	ms + 300
Melbourne Airport (A3/A-)	Aug-10	AUD	350	4,6	ms + 160-190
SPI (Australia) Assets (A3/A-)	Jul-10	AUD	500	5	ms + 185
APT Pipelines (Baa2/BBB)	Jul-10	AUD	300	10	ms + 240
Sydney Airport (Baa2/BBB)	Jun-10	AUD	175	5	ms + 265
Adelaide Airport (Baa2/BBB)	Mar-10	AUD	235	5.5	ms + 255
Transurban (Baa1/A-)	Mar-10	AUD	250	4	ms + 180

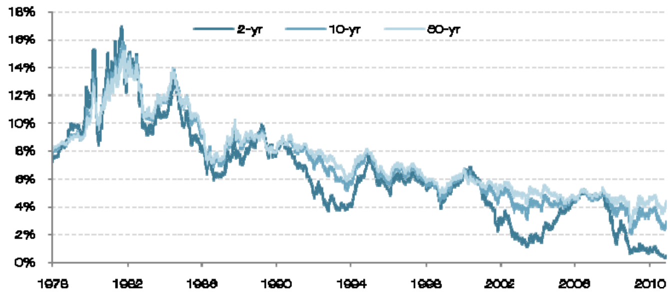
7.2.2 Foreign capital markets

Australian companies can issue bonds in offshore capital markets. As an example, the US debt capital markets have been an attractive source of funds for Australian companies looking for long-tenor debt due to the liquidity of the US market and prevailing low US interest rates. US Bond issuance can be undertaken through:

— A public bond offering which would require registration with the Securities and Exchange Commission and would require the provision of a prospectus

— The private placement market or 144A market which traditionally sources funding through investors seeking long duration investments. Private placements can only be offered to qualified institutional investors but can provide a more streamlined process with lower potential transaction costs as only a few institutional investors would usually be required and registration is not required with the SEC. In 2009, over 10 companies raised over US$3 billion in SEC 144 bonds and over US$7 billion in 144a bonds[xxvi].

Figure 8 – Record low yields on US Treasuries…



Source: Bloomberg

…results in attractive pricing for foreign issuers

Source: Bloomberg

The following table lists Australian companies that have recently issued bonds in the US private placement or 144A market.

Issuer	Date	Currency	Amt ($m)	Tenor (Years)	Spread to Benchmark (bps)
Toll Holdings (NR/NR)	Nov-10	USPP	275	5,7,10	UST + 180 (A$ms + 208-228)
Broadcast Australia (Baa2/BBB)	Nov-10	USPP	275	7,10	UST + 175 (A$ms + 212, 225)
Sydney Airport (Baa2/BBB)	Sep-10	US 144A	500	10.5	UST + 260 (A$ms + 322)
Asciano (Baa2*/BBB-)	Sep-10	US 144A	1,000	5,10	UST + 170-190 (A$ms + 205-245)
AGL Energy (NR/BBB)	Jul-10	USPP	300	12,15	UST + 215-235 (A$ms + 283-312)

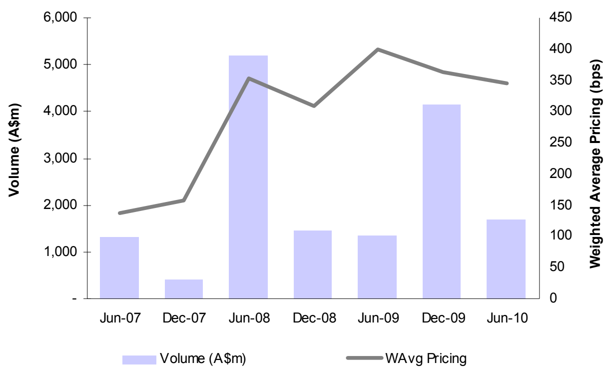
7.3 PROJECT FINANCE

The ability for a SENE or wind farm to arrange project finance will depend upon the expected cashflow profile generated by the project. Options that increase the predictability of cashflows are more likely to obtain more favourable project finance terms which will be reflected in improved debt covenants, gearing caps and coverage ratios. More favourable debt terms would result in higher expected equity IRRs and increase the likelihood of a project being commercially viable.

7.3.1 Project Finance Debt

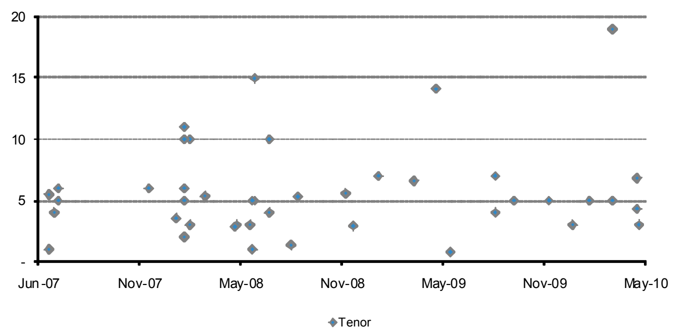
The recent increase in project finance market activity suggests stronger bank balance sheet support for high quality assets. Margins have begun to trend downwards and 5 – 7 year tenors are available. Margins are expected to narrow as liquidity continues to improve

Figure 9 – Project Finance Volume and Pricing



Source: *Bloomberg, LoanConnector*

Figure 10 – Project Finance Tenors



Source: *Bloomberg, LoanConnector*

The following table lists recent project finance raised for Australian projects. The specific margins and availability of debt for SENEs and wind farms will depend on their characteristics relative to the transactions listed below.

Borrower	Date	Tenor (yrs)	Currency	Amount (m)	Spread (bps)
Kwinana Swift Power Station	Sep-10	3	AUD	76	
Muja AB Power Station	Sep-10	10	AUD	150	
Port Waratah Coal Services Ltd	May-10	4, 7	AUD	100	270
Collgar Wind Farm Pty Ltd	Mar-10	5, 19	AUD	478	350
Pyrenees Wind Energy Developments Pty Ltd	Feb-10	5	AUD	335	325
AquaSure Finance Pty Ltd (Victorian Desalination Plant)	Sep-09	7	AUD	3,921	350-400
Pacific Hydro Ltd	Dec-08	3	AUD	262	N/D
Hallet Hill No 2 Pty Ltd	Aug-08	1	AUD	216	120
Braemar 2 Power Station	Jul-08	4, 10	AUD	365	N/D
EDL CSM (NSW) Pty Ltd	Jun-08	1, 5	AUD	320	N/D
DBNGP Finance Co Pty Ltd	Jun-08	3	AUD	340	625
Griffin Power Pty Ltd	Feb-08	2, 5, 6, 10, 11	AUD	1,015	135, 150
Epic Energy Australia Pty Ltd	Feb-08	4	AUD	165	N/D

Endnotes

i This will depend on whether an initial generator can satisfy the 25% cost threshold introduced for Option 1

ii This will depend upon the 'economic test' adopted for Option 2. An economic test that only requires demonstration of positive net market benefits for the selected option may be run in parallel with the proposed SENE process, but an economic test that requires analysis against a range of similar options has the potential to delay the project timeline

iii This is based on the total net present value of expected costs to customers, i.e. where the expected generation profile materialises. Option 1 and 2 are expected to be NPV neutral to customers, whereas customers the other Options face ongoing long term costs (Option 3) or do not subsidise customers for the initial amounts they fund during the ramp-up period (Options 4 and 5)

iv The 'Critical Issue' assessment is in recognition to concerns whether the regulated investment test can provide a sufficiently timely response in transmission investment to allow efficient renewable energy generation to be developed within the RET timeframes. The coordination issues resulting from multiple renewable generation projects that require access to a shared transmission asset results in an incremental approach in transmission investment that may hinder development of efficient large scale transmission and renewable energy investment

v This includes, but is not limited to capital expenditure, operating expenditure, parasitic and line loss factors, capacity factors and construction timelines provided by WorleyParsons, forward power price curves, net market benefits and RIT-T assessments provided by MMA

vi This may only be partially mitigated since subsequent generators may be willing to 'forcibly' constrain earlier generators if the penalties for constraining others are less than the benefits of receiving access rights. This would occur if the penalty is only linked to the annual SENE charge, but the benefit arises from revenues generated from higher dispatched electricity.

vii This will depend on whether an initial generator can satisfy the 25% cost threshold introduced for Option 1

viii This will depend upon the 'economic test' adopted for Option 2. An economic test that only requires demonstration of positive net market benefits for the selected option may be run in parallel with the proposed SENE process, but an economic test that requires analysis against a range of similar options has the potential to delay the project timeline

ix This is based on the total net present value of expected costs to customers, i.e. where the expected generation profile materialises. Option 1 and 2 are expected to be NPV neutral to customers, whereas customers the other Options face ongoing long term costs (Option 3) or do not subsidise customers for the initial amounts they fund during the ramp-up period (Options 4 and 5)

x The 'Critical Issue' assessment is in recognition to concerns whether the regulated investment test can provide a sufficiently timely response in transmission investment to allow efficient renewable energy generation to be developed within the RET timeframes. The coordination issues resulting from multiple renewable generation projects that require access to a shared transmission asset results in an incremental approach in transmission investment that may hinder development of efficient large scale transmission and renewable energy investment

xi Including the Australian Energy Regulator and Economic Regulation Authority of Western Australia

xii Fixed in real terms. The nominal SENE charge will escalate with inflation

xiii Assuming a wind farm commissioned in 2015 with a 15 year PPA at $120/MWh, with a capacity factor of 40% and an MLF of 0.885

xiv MMA estimate that the long term pricing for the bundled electricity and RECs will range from $109to $122.50 per MWh. MMA advise that This range can be used as a proxy for long term offtake contracts that wind farm generators could receive

xv MMA, July 2010, Pre-feasibility of wind generation on the Eyre Peninsula and assessment of market benefit of shared network augmentation

xvi The Green Grid scenario uses a Southern AC option as its preferred interconnection upgrade and is only assessed against a 'high carbon' scenario, where the implementation of frameworks that favour renewable energy are favoured and there is a strong supply side response to meet the policy framework

xvii The tradeable access right does not provide full protection against being constrained from the network, since it only applies to generators that connect to the SENE, and not the broader network. In addition, the potential lost revenues from being constrained may be greater than the compensation that the generator may receive for the tradeable access right, which would result in reduced overall profits

xviii The target equity return for wind farms is fluid, and the required IRR will depend upon the specifics for each project

xix The equity IRRs are based on nominal cashflows to equity and are post project vehicle tax, but pre investor-specific tax. The project structure assumes a standard project finance structure where equity is provided through redeemable preference shares xx Murraylink, Directlink and Basslink are examples of transmission assets in Australia that are or once were merchant assets. Murraylink and Directlink applied and were granted approval by the AER to be converted from an unregulated service to a regulated service on 1 October 2003 and 6 May 2004 respectively.

xxi The AEMC has addressed the issue of contestability and has not ruled out new entrants from delivering SENEs in the interests of maintaining the potential for new competition

xxii Source: Reuters

xxiii The annual SENE charge for planned generation that is yet to connect is underwritten by customers under Options 1, 2 and 5

xxiv The current rules do not indicate whether it is possible for a TNSP to seek approval for the classification of a SENE asset to be changed to a regulatory asset. This course of action may be preferred by the TNSP under Options 3 and 4 if planned generation does not arise and the initial generators default. If this it is possible to alter the classification, then it is likely the SENE would be assessed according to the RIT-T, and the SENE portion that passes the regulatory test may form part of the TNSP's RAB that receives a regulated return

xxv 145bps in cash, 100bps capitalizing which will increase to 200bps if $250m debt reduction target is not met by 31 March 2011

xxvi Source: Reuters