Trevor Armstrong
Executive General Manager
System Planning & Regulation

Level 9, 570 George Street
Sydney NSW 2000

Address all mail to:
GPO Box 4009
Sydney NSW 2001

Telephone +61 2 9269 2611
Facsimile +61 2 9269 7294

EnergyAustralia®

16 June 2010

Dr John Tamblyn
Chairman
Australian Energy Market Commission
Level 5, 201 Elizabeth Street
SYDNEY NSW 2000

Dear Dr ~~Tamblyn~~ John

EnergyAustralia's Submission on MCE Proposed Rule on Scale Efficient Network Extensions

On 13 May 2010, EnergyAustralia provided a submission to the AEMC in relation to a proposed Rule change relating to scale efficient network extensions (SENE). Our submission noted that EnergyAustralia was in the process of developing a realistic example to demonstrate the implications of applying a SENE framework. We are now in a position to submit the example to the AEMC, which we hope you will consider as part of your process for assessing the proposed Rule change.

In preparing the example, our intention has been to develop a realistic scenario that reflected the circumstances that may be experienced by a distribution network. This was to better understand the limitations and strengths of alternative regulatory frameworks in addressing the issue raised by the Rule proponent relating to disincentives for generators to connect. Our example compares:

- the existing regulatory arrangements;
- the proposed SENE framework in the Rule; and
- minor changes to the existing framework, as proposed by EnergyAustralia.

In our submission of 13 May 2010, we encouraged the AEMC to explore whether the potential market failure can be adequately addressed in the existing framework, with minor modifications where required. The example has afforded EnergyAustralia the opportunity to reflect on the nature and extent of the potential market failure that the Rule change is seeking to address. It has also provided us with an opportunity to identify minor amendments to the existing framework that would best address the issue and, as such, provides more details to support the position put forward in our submission.

The example reveals that the existing framework may provide a disincentive to small generators from connecting to the shared network, due to high dedicated connection costs. However, the example raises questions about whether regulatory intervention will result in a reduction in the overall costs of supplying renewable energy to the market. This re-affirms our view that there are only very limited circumstances where the existing framework may lead to inefficient outcomes, and that the framework should limit regulatory intervention to these rare cases.

The example also provides an estimate of the costs and risks that customers face under the proposed regulatory intervention to extend the shared network. The estimates demonstrate that customers pay a very high cost for delivered energy in the initial life of the SENE asset. Further, it reveals that the consumer bears the risks and costs of asset stranding, when this type of cost or risk would not arise under the existing framework.

In relation to this analysis, we note that a key weakness of the proposed SENE framework is that it has no quantitative basis for assessing whether an extension will deliver long term benefits to customers. In contrast, the example demonstrates how the regulatory test provides a more robust alternative than the SENE framework for assessing whether an augmentation will result in market benefits. This confirms a key theme of EnergyAustralia's submission that minor changes to the existing framework will better address the issue identified by the MCE, relative to the proposed SENE framework.

Our example has provided us with a better opportunity to detail the minor changes that could be made to the regulatory framework, including:

1. Similar to the proposed Rule, AEMO would have a planning role in identifying renewable generation zones. However, under our proposed approach AEMO would have increased accountability role to only identify areas which are very likely to result in customer benefits.
2. The DNSP would apply the regulatory test in AEMO nominated areas, if it receives a connection application for more than 25 per cent of the expected capacity of generation for that zone. Minor modifications of the regulatory test guidelines and/or Rules may be required to set out a clear process for DNSPs to assess market benefits in these cases. AEMO would also be required to provide generation forecast information to the DNSP including timing, size, location, capacity factors and cost of generation.
3. Minor amendments to Chapter 6 may be required to enable cost recovery during a regulatory period if the costs are not included in a building block determination.

Our approach has the advantage of working within the existing connection regime, investment test process and pricing arrangements, thereby avoiding the complexities of a SENE regime that sits outside these instruments. Further, the example makes clear that the SENE framework is less resilient in responding to issues that may arise in the later life of the extension, such as when new load arises in the SENE area, or when the asset is subject to significant refurbishment.

EnergyAustralia requests that the AEMC take into consideration the attached example when making its draft determination on the proposed Rule. We understand that the example is complex and, as such, we would like opportunity to present the case study to the AEMC in the near future.

In the meantime, if you have any questions on the attached example, please do not hesitate to contact Ms Jane Smith on 9269 4171.

Yours sincerely

TREVOR ARMSTRONG
Executive General Manager
System Planning and Regulation

Scale efficient network extensions example

Summary

The example described in this Appendix compares three alternative regulatory frameworks for the connection of generation to the network:

- The existing arrangements under the Rules;
- The new framework which would be established under the MCE's proposed SENE Rule changes; and
- A simplified EnergyAustralia proposal, based on minor changes to the existing Rules framework, including the use of the RIT for investment analysis.

The **key points** that follow from the example are:

1. There is a 'gap' in the existing planning arrangements. There would be benefit if AEMO undertook analysis to identify renewable zones that are likely to provide long term benefits to customers. This would limit (partially) customer funded extensions to circumstances where there is a potential failure with the existing regulatory framework.
2. There are potential disincentives in the existing framework for small renewable generators to connect to the shared network from remote areas. However, there is no compelling case to demonstrate that an extension of the network will result in lower overall costs for the renewable energy delivered to the market. In our example, an extension of the network still results in high connection costs (over 20 per cent of the generation costs) for the wind generators. Further work is required to establish whether extensions of the shared network will lower the delivered costs of renewable energy, relative to connecting generators more closely located to the shared network..
3. If an extension is built, the example shows that customers pay very high short term costs until new generation comes on board (potentially more than double the generation cost). If the new generation does not eventuate, the customer will continue to bear those high costs and the asset become at least partially stranded. This contrasts with the existing framework where customers do not take on any risk or cost associated with connecting generation. In this example, the investment recovery amount is $130 million over the life of the asset, of which customers would pay $39million (or over 30 per cent of total costs). This includes the short term costs which a consumer bears until new generators connect (approximately $16 million) and $23 million from the under-utilisation of the asset.
4. The SENE framework does not provide sufficient safeguards to consumers to ensure that decisions to augment the network will lead to long term customer benefits. EnergyAustralia's suggested modifications to the existing framework ensure more rigour and transparency in decisions to extend the network:
    - AEMO would become accountable for providing a greater level of detail in identifying areas which are likely to provide customer benefits and for forecasting generation profile.
    - The existing regulatory test (with minor modification) would be used to assess whether there are market benefits from the extension of the network, when no such test exists under the SENE framework.
    - A minimum generation threshold to trigger the construction of a shared generation connection asset would ensure that extreme stranding risks are minimised. The example demonstrates costs of $100 million over the life of the asset under extreme asset stranding.

5. EnergyAustralia's suggested approach involves only minor modifications to the existing framework and is therefore less administratively complex than the SENE framework. This includes the ability to connect under the existing regime in Chapter 5, using the existing investment test, and applying existing pricing Rules and principles.

6. Classifying the asset as providing direct control or prescribed services would result in simpler regulatory and pricing arrangements that provide appropriate cost reflective price signals to generators. It also better addresses circumstances where load connects to the SENE and/or refurbishment is undertaken on the asset.

1. Background

In our submission to the MCE of 13 May 2010, we noted that in very limited circumstances, there may be an economic reason for developing a single 'oversized' extension of the network to connect prospective generation. However, we also noted that:

- The existing regulatory test is the more appropriate instrument for assessing whether there would be a market benefit from extending the network, and for quantifying the 'optimal' size of the asset. This would also have the advantage of working within the existing regulatory framework to address the issue.
- In contrast, the proposed Rule will increase the risk that customers will bear the cost of a significant number of oversized and under-utilised assets. We also drew the attention of the AEMC to the complicated and duplicative economic regulatory arrangements that would be established by the proposed Rule.
- If the AEMC still considers the SENE framework to be the preferred model to address the issue, a number of adjustments would be required to ensure that the framework better promotes the National Electricity Objective. However we considered that modifications to the existing framework and instruments would more appropriately enable the current issue to be addressed.

2. Comparison between frameworks for addressing issue

The purpose of this example is to provide a realistic scenario to compare different connection regimes. Our example characterises some of the circumstances likely to be realised in a distribution network if there happened to be a large scale renewable development in its area.

The example compares:

(i) the existing regulatory arrangements;

(ii) the proposed SENE framework in the Rule; and

(iii) minor changes to the existing framework, as proposed by EnergyAustralia.

EnergyAustralia has given more detailed thought to the modifications that would be required to address a potential market failure since making its submission. These are detailed in the table below which compares the differences between the frameworks. Fundamentally however, EnergyAustralia considers that these minor changes would only be required in very limited circumstances, where it can be demonstrably shown that there is a potential market failure, and that a regulatory intervention would provide benefits to customer.

Regulatory Framework comparison

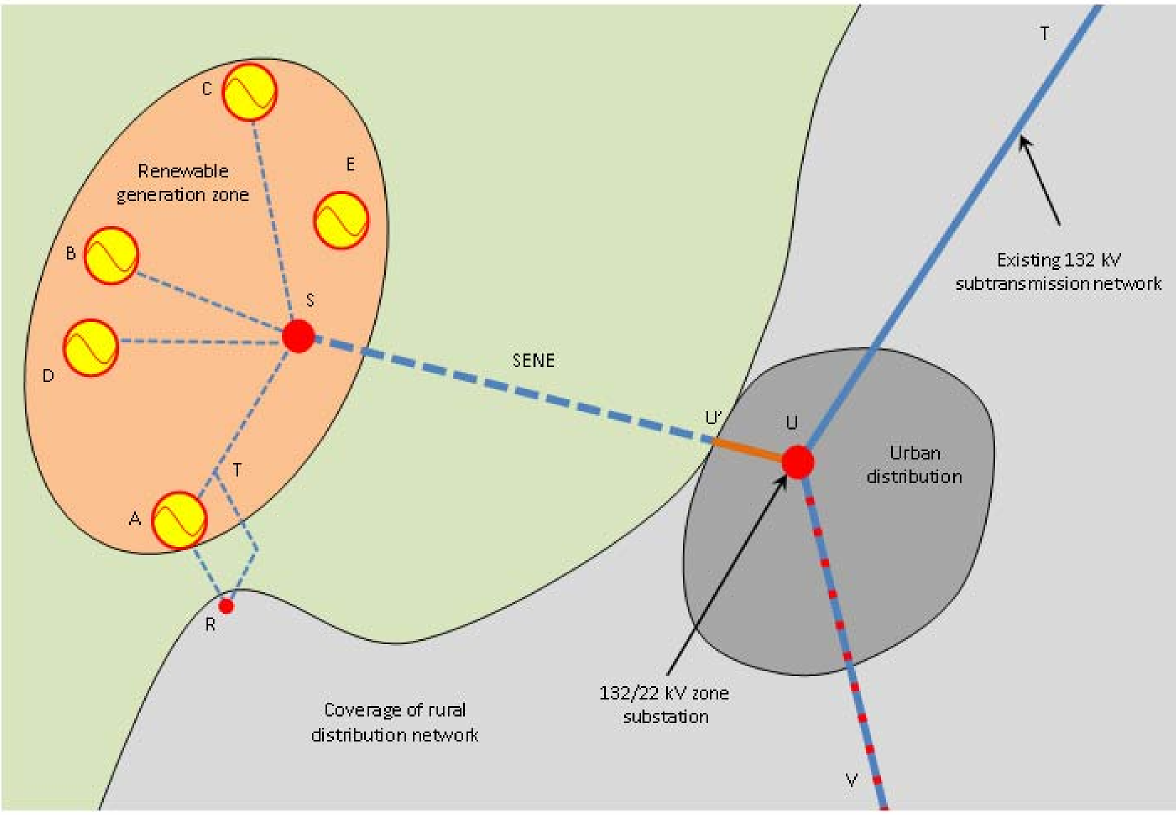
Existing Framework	Proposed Rule (SENE) framework	EnergyAustralia's proposed modifications to existing framework
Planning		
Currently no planning is undertaken to identify 'economic efficient' renewable generation zones.	AEMO would identify scale efficient generation zones where there is likelihood of substantial scale efficiencies.	AEMO would only identify areas above a minimum generation capacity (100 to 150MW) and at a pre-defined distance from the shared grid. AEMO would identify the benefits, costs and risks of each potential renewable zone. Based on this assessment, it would only identify areas where there is a strong likelihood that customers will benefit, given an assessment of the risks of network stranding.
	NSP would identify credible options as part of annual planning obligations.	AEMO would provide NSP with forecast generation development profile, and the NSP would undertake planning of credible connection options.
Connection		
Applicant (or joint application) would seek connection to the shared network. This follows the existing connection framework.	If a generator is located in the SENE zone it (presumably) must connect under the SENE connection processes.	Connection application/s (in an AEMO identified area) could trigger the application of the regulatory test.
No thresholds are applicable.	No threshold for trigger of SENE development.	Minimum threshold for trigger of extension would be 25 per cent of capacity of renewable generation zone, otherwise applicant would seek connection under existing framework.
Investment test		
No investment test, as applicant funds dedicated connection.	Subject to SENE planning report.	Regulatory test to determine whether market benefit to customers from extension. This may be subject to clarifications in the Rules and/ or guidelines on the assessment process to be undertaken by a DNSP.
	NSP would select the least cost design that meets total forecast generation in the area (with no requirement to demonstrate whether this least cost design is in the long term interests of customers).	NSP would be required to select the least-cost design to meet forecast generation capacity in the renewable zone.
	NSP would undertake forecast of expected generation and this would be verified by AEMO.	AEMO would provide forecast generation to the NSP including expected location, size and timing.

Existing Framework	Proposed Rule (SENE) framework	EnergyAustralia's proposed modifications to existing framework
Service classification		
For EnergyAustralia and other distributors that have been subject to an AER determination, the dedicated asset is classified as providing direct (generally standard) control services.	The SENE is deemed a 'negotiated' asset, although the Rule provisions for existing negotiated assets do not apply.	The asset provides direct (standard) control services, as an extension of the shared grid that provides market benefits.
Regulatory treatment		
The assets are included in the DNSP's RAB but at zero value. This is because the asset is built by the connecting applicant.	Capital and operating costs are not recovered under the regulated processes set out in Chapter 6 of the Rules, but are recovered under a negotiated arrangement with the applicant which must endure for the economic life of the SENE, and which must presumably provide for any replacement during that life. Network performance subject to a very complex 'capacity rights' compensation arrangement for the network assets that are shared by those connected to the SENE.	The extension would be subject to pass through/ contingent project provisions for the capex and opex (if not already included in the capex and opex forecasts at the time of regulatory reset). The capital costs of the extension are included in the NSP's RAB. For the future period, opex associated with the maintenance of the asset is included as part of the 5 yearly determination, as would be any future refurbishment costs. Service performance subject to AER's service target performance incentive scheme.
Funding of asset		
Customer funds the capital costs upfront. NSP also has the ability to charge the generator on an ongoing basis for upstream augmentation required as a consequence of the connection (under existing clause 5.5(f)(3)). Operating costs are recovered from load customers through network pricing arrangements.	Generators pay on a MW basis for their capacity allocation of the SENE. This is subject to 5 year reviews by the NSP, where any change to SENE connection charges must be approved by the AER. Unpaid for amount funded by customers (outside of X-factors). However it is unclear whether NSPs would be entitled to recover this amount through tariffs in the annual pricing proposal, or whether it would need to undertake a separate recovery process. . It is unclear whether NSP could charge generators for upstream augmentation of the network (under existing clause 5.5(f)(3)).	Generators pay cost reflective prices for their capacity use of the extension, and any upstream augmentation costs related to the capacity of nominated generation.

3. Setting the scene – the example

The example in Figure 1 has been formulated to highlight many the issues involved in the process of generator connection. In the example, a renewable generation zone has been identified by AEMO in an area remote from a Distributor's existing network. Whilst the example is distribution specific, the majority of the issues that are highlighted would apply equally to an extension of a transmission network.

Figure 1 - Hypothetical example of SENE application



4. Assumptions in example

(i) Generator development profile assumptions

It has been assumed in this example that there are a possible 5 generators in SENE zone, which would eventually be developed to deliver its forecast total capacity of 100MW. The sequence of the assumed generator development is as follows:

- Generator A (5MW) will be ready in Year 3;
- Generator B (5MW) will be ready by Year 5, bringing the SENE zone capacity to 10 MW;
- Generator C (15 MW) will be ready by Year 7, bringing the SENE zone capacity to 25 MW;
- Generator D (55MW) will be ready by Year 8, bringing the SENE zone capacity to 80 MW;
- Generator E (20 MW) will be ready by Year 10, bringing the SENE zone to its full capacity of 100 MW.

(ii) Network configuration assumptions

A number of assumptions have been made to render this example realistic and expose issues associated with generator connection and use of the network:

- The renewable generation zone is forecast by AEMO to have a potential capacity of 100 MW when fully developed;
- The generation zone is located 50 km from the nearest 132 kV subtransmission network T-U-V capable (with some augmentation) of absorbing the output of the zone. The SENE zone is proposed to be serviced by a hub at S;
- The SENE zone is sufficiently close to the 22 kV rural distribution network that a generator at A with a capacity of up to 5 MW could connect to it, at R;
- If the generation capacity in the zone were to exceed 50 MW, the 22 kV switchgear in the 132/22 kV zone substation at U would require replacing with equipment of higher fault rupturing capacity, to cope with the increased fault levels. Absent the renewable generation input, this equipment would serve for the remainder of its economic life;
- If the renewable generation in the zone were to exceed 80 MW, the original 132 kV subtransmission line U-V would require upgrading, to increase its thermal capacity to export generation to the remainder of the network. Fortunately the poles are sound and can be reused by elevating the existing conductor on pole extensions. Absent the renewable generation input, upgrading would not be required for the foreseeable future;
- Although not evident at the time of the initial design of the shared generator connection, during the consultation and environmental approval phase of construction, it was determined that the line was required to be undergrounded in the urban area, from U-U', at substantial additional cost;
- Some 10 years after the development of the SENE, the development of agribusinesses in the rural area near R requires the existing 22 kV distribution system to be reinforced. The most economical way in which this may be carried out at the time is to extend the 22 kV system from T to R, making use of the generation capacity in the SENE zone and the nearby generator A connection assets; and
- Some 20 years after the establishment of the SENE line S-U, which had a design and economic life of 40 years, it is discovered that the aluminium conductor has been damaged. Metal fatigue was caused by aeolian vibration, in the area of exposure to strong prevailing winds. It is necessary to repair the damage by replacing a substantial length of conductor and installing additional vibration dampers on the line.

(iii) Costing assumptions

The capital and operating cost elements which have been assumed to be associated with various elements of this example are set out in C.

Cost elements (real, $'000)

Element	Capital	Operating	Annual
Dedicated connections:			
Generator A to R 22 kV	$425	$6	$53
Generator A to S 22 kV	$750	$11	$93
Generator B to S 22 kV	$1,000	$15	$124
Generator C to S 22 kV	$1,000	$15	$124
Generator D to S22kV	$1,000	$15	$124
Generator E to S22kV	$1,000	$15	$124
SENE connection:			
SENE 132/22 kV zone substation at S	$15,000	$225	$1,863
SENE 132 kV line S to U	$10,000	$150	$1,242
SENE 132 kV line S to U with undergrounding U' to U	$14,000	$210	$1,739
SENE 132 kV connection at U	$1,000	$15	$124
Shared infrastructure:			
Upgrade 132/22 kV zone substation U fault capacity	$10,000	$150	$1,242
Upgrade 132 kV line U to V capacity	$4,000	$60	$497
New 22 kV line T to R	$425	$6	$53
SENE asset refurbishment:			
Repair damaged conductor	$1,000	$15	$124

(iv) Generation costs and capacity factor assumptions

In a recent comparison of the costs of renewable energy generation, MMA estimated that the cost of wind generation is $102/MWh in 2020, declining to $96/MWh in 2030[1]. These costs were in mid 2008 dollar terms for energy delivered to the Regional Reference Node of the market and "do not include transmission costs other than modest connection charges". For the purposes of highlighting the comparisons in this example, the 2020 wind generation cost figure was escalated using the March quarter CPI over two years, to mid 2010. The escalated cost is $108/MWh.

The capacity factor of wind generators will vary markedly with their location, which is determined by the wind regime, and by the turbine design and reliability. Capacity factors in the range of 25 to 40% are claimed (by their proponents) to be common[2]. For the purpose of this illustrative example, an annual capacity factor of 30% has been assumed for wind generators. Thus for a 5MW generator, the annual energy output would be 5*8,760*30% = 13,140MWh.

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1 McLennan Magasanik and Associates, Report to AGEA - Comparative Costs of Electricity Generation Technologies, February 2009.

2 American Wind Energy Association http://www.awea.org/faq/wwt_basics.html.

Whether an individual generation project would prove economic to proceed depends upon the total cost to the proponents of its delivered energy to the market, in which it must compete to generate. There are a number of components of this analysis:

- The capital and operating costs of the generation plant; less
- Renewable energy subsidies; plus
- Electrical losses (transmission and distribution); plus
- Network (transmission and distribution) connection and use of system costs.

Network connection costs that substantially increase the delivered cost of energy to market from a generation project would render a project non-viable. This is appropriate from the perspective of customers, who would otherwise bear the total cost of generation.

This example has been simplified, in that it has not considered the costs associated with electrical losses for the alternative renewable generation configurations. The associated effects (on the cost and volume of generated output) would be likely to amount to a few percent of the generator output and thus are less material than capital costs associated with extension of the network.

However it should be noted that a generator connecting to a distribution network may be assigned both a distribution loss factor and a transmission loss factor, for the purpose of market settlements. In the distribution situation depicted in this example, the transmission connection point and transmission loss factor is likely to be common for generators in the same vicinity. However, the distribution loss factor would be influenced by the following considerations:

- Generators connecting to a shared connection asset would have a distribution loss factor which ***reduces*** the quantum of their output in market settlements, by the losses in the SENE as well as the losses in their connection assets; whereas
- A generator connected within a distribution system would have a distribution loss factor equivalent to the loads in the area, which acts to ***increase*** the quantum of its output in market settlements.

5. Series of events in example

The following stages are associated with the example, and are depicted in turn, in section 6.

(1) No generator has connected

This seeks to demonstrate the planning and initial design work that would be undertaken under each framework prior to connection of asset.

(2) Generator A applies to connect (5MW)

This shows the costs faced by Generator A, and the customer, under each framework.

Under this sequence, it also becomes apparent that a proportion of the SENE will need to be undergrounded, but this occurs after connection offer is provided in SENE framework.

(3) Generator B seeks connection (5MW)

This shows the costs faced by Generator A, Generator B, and the customer under each framework.

(4) Generator C seeks connection (15MW)

This shows the costs faced by Generator A, Generator B, Generator C and the customer under each framework.

(5) Generator D seeks connection (55MW) but Generator E (20MW) does not connect

This shows the costs faced by Generator A, Generator B, Generator C, and Generator D and the customer under each framework.

This also shows that upstream infrastructure development would be required if Generator D connected.

Under this sequence, Generator E does not apply for connection as forecast, meaning that the anticipated capacity of the SENE was not met.

(6) Augmentation of the distribution system to meet load

This shows how the frameworks would efficiently construct/use network to meet new load demand near the SENE region.

(7) Refurbishment of the SENE asset

This shows how the frameworks would adapt if a significant refurbishment of the SENE asset.

6. SENE example – Outcomes under each sequence

Sequence 1: No generator has connected – Initial planning (Year 0)

Key point: This demonstrates that there is a 'missing' planning role in the current arrangements. More detailed analysis from AEMO would support the identification of areas that are likely to have long term benefits for customers, and may also promote transparency to encourage coordinated connections.

Under EnergyAustralia's suggested changes, AEMO has greater accountability in nominating zones, and a greater role in undertaking preliminary assessment of the benefits, risks and costs in different zones. AEMO's role would thereby limit extensions to where it is demonstrable that there is a market failure with the existing regime.

Existing arrangements	MCE proposed Rule change (SENE)	EnergyAustralia modifications to existing framework (Extension)
1. Identifying renewable generation zones and connections		
No planning actions required - response to connection inquiry only.	AEMO identifies zones (including generation capacity) where renewable generation may require the development of shared generation assets, as part of the National Transmission Development Plan.	
	▪ AEMO identifies areas of material scale efficiencies. There is no size or distance threshold and no role for economic assessment of customer benefits.	▪ AEMO forecasts the expected priority of renewable development between (and if feasible, within) generation clusters, in order that generation planning may be integrated with other aspects of planning the network. ▪ AEMO would also undertake initial analysis of customer benefits, risks and costs, and only nominate clusters that are likely to lead to net benefits to customers (that is, lower electricity prices) ▪ AEMO also nominates a reasonable minimum generation threshold level that would trigger the extension of the network, based on the economic plant size and approximate costs of connection (in this example, assumed to be 25%).
	▪ DNSP identifies connection asset U-S as a credible connection to the renewable generation zone and undertakes preliminary planning in its Annual Planning Report. ▪ The DNSP also identifies the additional impact of this renewable generation on the network, which would require fault level augmentations at U and capacity augmentation from U to V.	▪ Same as SENE framework, except additional time to prepare credible options.

Existing arrangements	MCE proposed Rule change (SENE)	EnergyAustralia modifications to existing framework (Extension)
1. Identifying renewable generation zones and connections		
	▪ The preliminary estimate the SENE asset cost (excluding undergrounding) is $26M, or $3.2M p.a. This equates to $32/MW p.a. for the fully developed 100 MW capacity of the generation zone. More detailed investigation has not been undertaken on the upstream augmentation costs, so this cost has not been included in the preliminary estimate.	▪ The preliminary estimate the SENE asset cost (excluding undergrounding) is $26M, or $3.2M p.a. for the fully developed 100 MW capacity of the generation zone. More detailed investigation has not been undertaken on the upstream augmentation costs, so this cost has not been included in the preliminary estimate. ▪ Preliminary estimates of the charges associated with providing shared network infrastructure (including upstream costs) are made available to prospective connection applicants.

Sequence 2: Generator A applies to connect (Year 3)

Key point: This demonstrates shows that in some cases it may be more cost efficient for the small generator to connect to the local network, rather than connecting to the SENE.

It also demonstrates the importance of a materiality threshold, as the customer is bearing a very high cost in the initial years of the SENE's economic life until new generation comes on board (over $3 million, leading to a total cost of generation of $400/ MWh in that year)

Existing arrangements	MCE proposed Rule Change (SENE)	EnergyAustralia proposed modifications (Extension)
2. Connection of generator A - up to 5MW capacity		
Dedicated generator connection A-R is identified as the least cost option. The up-front costs met by the generator. There are no upstream augmentation costs for this connection.	▪ Generator A is (presumably) required to seek connection under the SENE regime. Based on a prospect of 100MW capacity, and material scale efficiencies from its development, the DNSP undertakes planning in accordance with the SENE planning report guidelines, where asset U-S is found to be the least cost design. ▪ Generator A is quoted $32/MW p.a. for the proportionate use of SENE assets. ▪ Dedicated generator connection A-S is identified as the least cost option of connecting Generator A to the SENE hub. This is treated as a negotiable service and its up-front costs met by the generator. As for each of the scenarios below, the negotiated agreement for a dedicated connection would need to include conditions which require the generator to pay for the replacement of the dedicated asset, if it fails before the end of its economic life. ▪ Connection offer is made on the basis of initial cost estimate, and SENE charge is approved by the AER. However, in gaining planning approvals, DNSP is required to underground U'-U, but the SENE charge cannot be altered for Generator A for 5 years.	Existing connection processes would apply as threshold would not have been met to trigger network extension. Dedicated generator connection A-R identified as the least cost option. The up-front costs are met by the generator. There are no upstream augmentation costs for this connection.
Generation cost Generator meets up-front connection cost of $425,000.	***Generation cost*** The generator A-S connection cost is $750,000 ($93,000 pa) In addition, the proportionate cost of the SENE asset to the	***Generation cost*** Generator meets up-front connection cost of $425,000. As with the existing arrangements, the cost of generation supplied to the

Existing arrangements	MCE proposed Rule Change (SENE)	EnergyAustralia proposed modifications (Extension)
2. Connection of generator A - up to 5MW capacity		
The cost of generation supplied to the market is: $108 + $53,000/13,140 = $108 + $4 = **$112/MWh**	5MW generator is $161,000 p.a. Total cost of generation to customers would be: $108 + $93,000/13,140 + $161,000/13,140 = $108 + $7 + $12 = **$127/MWh**	market is **$112/MWh**
Residual network cost met by customers There is no additional infrastructure cost to be met by loads.	***Residual network cost met by customers*** The capital cost of the SENE is increased by the requirement to underground and escalates to $30M. Customers meet the additional cost less the SENE contribution by the generator. The amount funded by customers is $3.54M p.a. As with the scenarios below, there is no explicit mechanism for NSPs to recover these costs from customers through tariffs in the annual pricing proposal.	***Residual network cost met by customers*** There is no additional infrastructure cost to be met by loads.
Total delivered cost The total cost of energy delivered to the market is **$112/MWh.** ***Note:*** distribution losses have not been accounted for in this calculation but in the case of this generator A, its distribution loss factor would be the same as that of equivalent loads within the distribution network, which depending upon the location and network configuration would be in the order of 1.05 to 1.10. Generator A acts to reduce losses in the distribution network and accordingly would be paid this increased price for energy generated. The associated additional costs would be met by	***Total delivered cost*** If the generator proceeds, then expressed over the output of the 5MW generator, customers will pay: $127 + $3,540,000/13,140 = $127 + $271 = **$399/MWh**. This elevated $/MWh cost will persist until further development of the renewable generator zone takes place, noting that Generator B will be ready two years after Generator A. It should also be noted that the stand-alone cost of connection of the 5MW generator is that which would apply to its connection to R. The total cost to the generator would be $112/MWh under this arrangement, as for the existing arrangements and the EnergyAustralia proposal. This would mean that the cost to the generator would be higher than the stand-alone costs of connection. Compulsory obligation to connect to the SENE may discourage Generator A from connecting.	***Total delivered cost*** The total cost of energy delivered to the market is **$112/MWh**. See note at left on distribution losses.

Existing arrangements	MCE proposed Rule Change (SENE)	EnergyAustralia proposed modifications (Extension)
2. Connection of generator A - up to 5MW capacity		
load customers.		

Sequence 3 - Generator B (5MW) seeks connection (year 5)

Key point: This demonstrates that the standalone costs for a small generator may create disincentives to connect. In this case, the SENE solution would redress the disincentives for Generator B to connect. However, the customer would to pay a high proportion of the residual costs of the SENE asset (over $3 million per annum, and total delivered costs is still above $250/MWh) until new generators come on board. Further, if Generators C and D did not proceed the customer would pay approximately $120 million from asset stranding. In this case, minimum thresholds for triggering SENE construction would ensure that this extreme stranding risk is mitigated.

Existing arrangements	MCE proposed Rule change (SENE)	EnergyAustralia proposed modifications (Extension)
3. Connection of generator B - second 5 MW of capacity		
A connection similar in voltage and configuration to that afforded by the SENE asset, but of lower capacity, is identified as the stand-alone connection option for this generator.	▪ SENE asset U-S has already been built. ▪ Dedicated generator connection is B-S is identified as the least cost option of connecting to the SENE hub. This is treated as a negotiable service and its up-front cost met by the generator. ▪ As the SENE asset has now been installed, the cost of its partial undergrounding has been incorporated into the cost share for this generator. ▪ Generator B is thus quoted $186,000 p.a. for the proportionate use of SENE assets (ie. greater than Generator A).	The second, 5MW generator does not trigger the development of the SENE asset as it is below the threshold for the renewable generation cluster, of 25% (noting that Generator A would have already connected and Generator C is not in a position to connect as yet)
Generation cost (B) The capital cost of a stand-alone connection with lower capacity than the SENE but sufficient for this generator alone could be in the order of $1M + (50-70%)*$26M, or some $14-18M. The cost of this connection would amount to **$151-208/MWh** and in the face of this, the generator clearly would not proceed to connect.	***Generation cost (A and B)*** The generator B-S connection cost is $1M ($124,000pa) In addition, the proportionate cost of the SENE asset to the 5MW generator is $186,000 p.a. Total cost of generation supplied to market would be: $108 + $124,000/13,140 + $186,000/13,140 = $108 + $9 + $14 = **$132/MWh**	***Generation cost (B)*** The cost of connection for the generator would be the same as for the existing arrangements and it would not proceed. The cost of this connection would amount to **$151-208/MWh** and in the face of this, the generator clearly would not proceed to connect.

Existing arrangements	MCE proposed Rule change (SENE)	EnergyAustralia proposed modifications (Extension)
3. Connection of generator B - second 5 MW of capacity		
	Residual network cost met by customers The second generator B contribution of $186,000 p.a. towards the SENE asset further offsets the SENE asset charges being borne by customers. The annual costs met by customers are reduced to $3.378M per annum.	
Total delivered cost Generator A = **$112/MWh** Generator B does not connect	***Total delivered cost*** Expressed over the average output cost of the two 5MW generators, customers will pay: $130 + $3,378,000/26,280 = $130 + $129 = **$258/MWh**. This elevated $/MWh delivered cost will again persist until such time as further development of the renewable generator zone takes place.	***Total delivered cost*** The total cost of energy delivered to the market is **$112/MWh** from Generator A only (as generator B does not connect)

Sequence 4: (i) Generator C seeks connection; and (ii) if Generator B has not connected it seek joint connection with Generator C (Year 7)

Key point: This demonstrates that there may still be a disincentive to invest for generator B and C under the existing framework, as even with a coordinated connection, the standalone costs for both parties means that it will be a marginal decision to enter the market.

The proposed Rule would mean that Generator C can connect to the SENE at a reduced cost, and is more likely to enter the market. However, this comes at significant costs to customers (approx $2.8 million per annum until new generator comes on board) and asset stranding risks. Further, no assessment of customer benefit has been taken to justify these costs and risks.

Under EnergyAustralia's proposal, the connection application triggers the application of the regulatory test, which will test whether there is a 'market benefit' from extending the network to meet the generation in the area. While the costs and risks are the same as the SENE, there are two primary advantages of this approach over the SENE framework. Firstly, it works within existing frameworks including the connection process, investment test, and pricing processes. This greatly reduces the complexity of the scheme. Secondly, the regulatory test provides a transparent and quantitative method to assess whether the extension of the network provides market benefits.

Existing arrangements	MCE proposed Rule Change (SENE)	EnergyAustralia proposed modifications (Extension)
4. Connection of a total of 25MW of generation capacity at A, B and C		
If the generator applications were coordinated, a shared connection similar in voltage and configuration to that afforded by the SENE asset, but of lower capacity, is identified as the stand-alone connection option for this generator. The capital cost of this plus the dedicated connections would be in the order of $2M + 80%*$30M, or some $26M. It is just possible that the generators would proceed to connect at this cost level.	Dedicated generator connections B-S and C-S are identified as the least cost option of connecting to the SENE hub. They are treated as a negotiable service and their up-front cost are met by the generator. The generator costs are estimated in the same manner as the above example, with the exception that the utilisation of the SENE asset is now increased to 25%.	▪ This level of generation was nominated by AEMO as sufficient to trigger the consideration of an extension to the shared network. ▪ The NSP is required to undertake a RIT-D (or slight modified or targeted RIT-D limb) which assesses the market benefits of undertaking an extension of the shared network, and which indicates the least cost design. ▪ For the purposes of the example, the extension is shown to generate market benefits (assuming forecast generation supplied by AEMO). The least cost option is to build a line U-S (with undergrounding between U-U') ▪ The asset is either included in the building block proposal, or if the RIT-T has not been completed, it will be subject to a new pass through provision to enable cost recovery of the financing and operating costs of the asset during the period. ▪ As the asset has passed the regulatory test, the asset becomes part of the DNSP's RAB. Generator B and C pay cost reflective charges (based on capacity use of the asset according to installed capacity). As such, this would mimic the existing economic and pricing principles for large customers, and would result in similar charges to

Existing arrangements	MCE proposed Rule Change (SENE)	EnergyAustralia proposed modifications (Extension)
4. Connection of a total of 25MW of generation capacity at A, B and C		
		generators and customers as under the SENE Rule. ▪ Dedicated generator connections B-S and C-S are identified as the least cost option of connecting to the SENE hub, and a connection offer is prepared on the basis of the existing framework.
Generation cost (B and C) Each generator meets the up-front connection cost of $1M and a share of the cost of the connection from S to U. Total cost of generation supplied to the market would be: $108 + $3.23M/65,700 = $108 + $49 = **$157/MWh** ***Note:*** It is unlikely that generators would proceed at this level of connection cost.	***Generation cost (A,B and C)*** The generator B-S and C-S connection costs are $2.0M in total. The proportionate cost of the SENE asset to the 25MW generators is $0.93M p.a. The total cost of this tranche of generation supplied to the market would be: $108 + $248,000/67,500 + $0.93M/67,500 = $108 + $4 + $14 = **$126/MWh**	
Residual network cost met by customers There is no additional infrastructure cost met by loads.	***Residual network cost met by customers*** The generators at B and C would contribute $0.9M p.a. towards the SENE asset. The residual annual costs met by customers are reduced to $2.8M per annum.	
Total delivered cost Generators B and C = **$157/MWh**. Generator A = **$112/ MWh**	***Total delivered cost*** Expressed over the 25MW output of the two generators at B and C, customers will pay: $126 + $2.8M/67,500 = $126 + $43 = **$168/MWh.** Whilst this total delivered cost is higher than that provided by the existing arrangements, it does provide for a system capable of supporting an additional 75MW of generation. There is however, a significant cost difference to customers compared with the existing arrangements which would continue to be borne if the expected generation forecast does not eventuate.	

Sequence 5: Generator D (55MW) seeks connection to the SENE (Year 8) but Generator E withdraws from the market, citing better development opportunities in other areas.

Key point: The withdrawal of generator E results in customers paying for the costs associated with asset stranding for the remainder of the asset's life. The risks of stranding would have been far higher if Generator D did not come aboard as forecast. The scenario also highlights the issue of whether generators or customers should pay for upstream augmentation costs. In this case, the entry of generator D results in the need to augment the network. Existing clause 5.5(f)(3)(i) provides for 'use of system services' charges to be paid by the connection applicant in relation to any augmentations or extensions required to be undertaken on all affected transmission and distribution networks. In our view, the preferred approach is to require all connected generators to pay for the augmentation of the network (in accordance with their contribution to the capacity of the line) through regulated network charges.

Existing arrangements	MCE proposed Rule Change (SENE)	EnergyAustralia proposal (Extension)
5. Generator D (55MW) seeks connection but Generator E withdraws		
Generator D would have a standalone dedicated connection. It is assumed that generators A, B and C have connected to the SENE framework, resulting in the need to upgrade of switchgear at U and capacity upgrade of 132 kV line U-V due to generation causing faults at 80MW capacity.	Generator D connects to the SENE. Generators A, B and C have connected to the SENE framework, resulting in the need to upgrade of switchgear at U and capacity upgrade of 132 kV line U-V due to generation causing faults at 80MW capacity.	It is assumed that generators A, B and C have connected to the SENE framework, resulting in the need to upgrade of switchgear at U and capacity upgrade of 132 kV line U-V due to generation causing faults at 80MW capacity.

Generation cost (Generator D) The capital cost for dedicated connection would be in the order of $1M + 80%*$30M, or some $25M. Under the existing framework, Generator D could have to fund the augmentation, as it is the connection applicant that triggers the need for the upgrade. Generators B and C would not pay any costs associated with the upstream augmentation. In certain cases, Generator D may not have to fund the augmentation on the basis that it would have been required in any case (for example due to load demand in the area). For this simplified example, we will assume that the costs of the extension are borne by Generator D. Total costs met by generator D is: $108 + $25M/144,540 + $1.74M/144540 $108 + $29 +12= **$141/MWh**	***Generation cost (A, B, C and D)*** It is unclear as to whether clause 5.5(f)(3) would apply under the SENE framework. It is assumed for this example that the upstream augmentation costs are met by customers, rather than the generator. This assumption does not alter the total delivered costs, but increases the amount borne by customers. The generator D-S connection cost is $1M ($124,000 p.a) In addition, the proportionate cost of the SENE asset to the 55MW generator is $2,049,000 p.a. Total cost of generation supplied to market would be: $108 + $124,000/144,540 + $2,049,000 /144,540 = $108 + $1 + $14 = **$123/MWh** Even if clause 5.5(f)(3)(i) were to apply, the SENE framework does not provide a practical mechanism for enabling the NSP to recover the upstream augmentation costs from generators. The NSP would have to wait until the next review period (of up to 5 years) before it can alter the charge that applied to Generator A, B and C.	***Generation cost (A, B, C and D)*** Under our proposed approach, the costs of the upstream augmentation would be recovered on a cost-reflective basis from each generator connected to the extension. This would be recovered through regulated network charges in a pricing proposal, similar to the process that would occur for a load customer. This would be consistent with the concept that the extension has been built for all connected generators, and that they should pay for their contribution of the asset. It would be useful for the AEMC to clarify that clause 6.1.4 (prohibition for DUOS charges for the export of energy) would not prevent a DNSP from charging generators regulated network charges for their contribution to the extension and augmentation of the network. We consider that the preferred view in this case is that a NSP is entitled to charge a generator for use of system charges in accordance with clause 5.5(f)(3). The prices for all generators in the zone would be increased to trend to a capacity increment equivalent to $8/MWh. Generators would thus meet similar cost for connection and shared assets as at left, plus the generator DUoS price. Total cost of generation supplied to market would be: $123 + $8 = **$131/MWh**
Residual network cost met by customers Customers would not pay for augmentation of the asset.	***Residual network cost met by customers*** It is assumed that customers meet the $14M cost of upstream augmentation at left, in addition to the residual 20% share of SENE asset costs. Expressed in terms of a $/MWh figure over the total of 80 MW of generation in the renewable	***Residual network cost met by customers*** Customers meet the residual 20% share of SENE asset costs. This included the residual costs of the augmentation of the network. Expressed in terms of a $/MWh figure over the total of 80 MW of generation in the renewable zone, this is: $0.75M/210,240 = **$1/MWh**

Total delivered cost Customers will pay approximately: Generator D =**$141/MWh** Generators B and C **= $157/MWh** **Generator A = $112/ MWh**	zone, this is: 1.74M/210,240 + $0.75M/210,240 = $8 + $4 = **$12/MWh** ***Total delivered cost*** Averaged over the 80MW output of the generators in the zone, customers will pay approximately: $124 + $12 = **$136/MWh**	***Total delivered cost*** Averaged over the 80MW output of the generators in the zone, customers will pay approximately: $132 + $1 = **$136/MWh**

Sequence 6: Augmentation of the distribution system using SENE assets

Key point: Classifying the extension (SENE) as a negotiated asset will mean that a DNSP has an incentive to bypass the SENE by (inefficiently) duplicating network to meet new demand in the SENE area. If the asset is classified as providing direct control/prescribed services (from shared assets), then a DNSP would cost effectively connect load, and charge customers on a cost reflective basis. Load will more likely connect in a distributor's network area, and this issue should be considered in any decision to classify the asset as providing negotiated (connection) services.

Existing arrangements	MCE proposed Rule change (SENE)	EnergyAustralia proposed modifications (Extension)
6. Development of a load connection to the SENE and generator connection assets		
It needs to be noted that the configuration of the connection R-T shown in Figure 1 as a support to the distribution network would not utilise the capacity of the SENE asset, because the generation in the SENE zone would exceed the capacity used by the distribution load. As the distribution load would absorb a portion of the SENE zone generation capacity, such a connection would act to increase the available capacity for generation export in the area, by reducing the flow in the SENE asset. It would also ensure that the relevant customer utilising the network pays for the asset through regulated prices.		
▪ Until such time as a generator connection asset has been built, there is no spare capacity to connect load. ▪ Once such a generator connection was in place, connection would take place as shown and the connection R-T would become a portion of the distribution RAB, providing prescribed services to distribution load customers.	▪ The negotiated services nature of the SENE and the associated generator compensation agreements may not permit the utilisation of the SENE network in the manner indicated. This is because the line is notionally a shared connection asset used by the connected generators. The proposed compensation regime may also provide a disincentive for the distributor to connect load to the SENE asset. ▪ The outcome would be that the DNSP would choose to undertake an uneconomic approach of building additional network between R-T, which would be a prescribed service. Customers would continue to pay for the stranded asset, while also paying for the duplicated augmentation to the load near R.	▪ As the asset is a prescribed asset in the RAB, the asset already provides direct control (standard) services. The DNSP could simply connect new load, and through cost reflective prices, ensure that the newly connected load pay for their proportionate use of the asset if this were appropriate. However for the example shown the loads do not make use of the SENE asset, rather a proportion of the capacity of generation in the SENE zone. ▪ As the capacity of the network elements shared by generators is not affected by this connection, generator pricing would remain unaffected.

Sequence 7: Refurbishment of the SENE asset

Key point: Classifying the SENE as a negotiated asset, and subjecting generators to SENE charges, will be complicated if (i)capital costs are incurred on the asset during its life (ii) due to refurbishment, the asset has a longer life (iii) when the asset needs to be replaced.

Existing arrangements	MCE Rule proposed Rule change (SENE)	EnergyAustralia suggested modifications (Extension)
7. SENE asset refurbishment halfway through its life (after 20 years) – which extends the life of the asset from 40 years to 50 years		
▪ This will depend on whether the dedicated assets are classified as negotiated or prescribed services. ▪ Currently, for DNSPs the AER classifies the asset as providing standard direct control services. While the capital costs are paid upfront by the customer, the asset is 'gifted' back to the DNSP and has a zero dollar value in the RAB. ▪ In this case, the costs of shared asset refurbishment would be included in the DNSP's RAB and recovered from customers.	▪ The SENE has been classified as a negotiated service and the terms and conditions associated with its use contained within a 'bundled' connection offer that also includes the generator connection assets. ▪ The offer is prepared by the DNSP in response to a generator's connection application on the basis that the asset has a life of 40 years, and would subsequently require the DNSP to meet the costs of the asset over that period of time. We note that the SENE charge itself may be varied every five years. ▪ Unless the potential refurbishment of the SENE asset had been foreseen and included within the terms and conditions of the connection offer and connection contract with the generator, the DNSP would be unable to recover the cost of the refurbishment from the generators using the capacity of the SENE. It is considered unlikely that such a premature failure would have been foreseen.	▪ The costs of shared asset refurbishment would be included in the DNSP's RAB. ▪ Costs would be recovered from generators and customer as appropriate, on a cost reflective basis under the pricing provisions in the Rules.

7. Discussion of outcomes

An indication and brief notes on this example as to whether economically efficient outcomes would have been achieved with the three regulatory regimes are contained in the table below. The overall cost, which includes that of the delivery of energy to the market plus residual network costs met buy customer, is shown for some examples. This may be compared with the generation cost of $108/MWh.

Table 1 - Economic efficiency of outcomes , total delivered costs and costs to customer

Economically efficient solution	MCE proposed Rule change	EnergyAustralia's modifications
Scenario 1 - Initial planning		
No identification of renewable generation zones.	AEMO identify areas of remote generation. AEMO do not have accountability for only identifying areas where there is a high likelihood that customers will benefit.	AEMO is accountable for nominating areas that are likely to result in long term benefits to customers, given the risks and costs faced by customers.
Scenario 2 - Connection of generator A - up to 5MW capacity		
Least cost solution is to connect A-R.	Premature triggering of SENE construction increases costs to customers, who would bear the whole cost of the SENE and the risk of it becoming stranded.	Provides efficient solution as per existing framework.
Cost: $112/MWh for Generator A	Cost: $399/MWh	Cost: $112/MWh
Customer pays $0	Customer pays $3.54 million p.a until new generation connects	Customer pays $0
Scenario 3 - Connection of generator B - second 5 MW of capacity		
It is not economic to connect this generator.	SENE asset is significantly underutilised with customers bearing the residual costs. Risk of very high stranding costs.	The proposed 25% threshold for SENE development provides an efficient solution that avoids potentially significant stranded asset costs being borne by customers.
Cost $112/MWh for Generator A Generator B does not connect	Cost: $258/MWh	Cost $112/MWh for Generator A Generator B does not connect
Customer pays $0	Customer pays $3.38 million p.a until new generation connects	Customer pays $0
Scenario 4 - Connection of 25MW of generation capacity at C (and B if not connected already)		
At this level of generation a connection is more likely to be efficient, given future generation development.	No test of market benefits, meaning there is no assurance that customers will benefit from the investment in the long term. "Oversized" SENE asset is less likely to be stranded. Residual costs met by customers.	Regulatory test provides assurance that there is a likelihood of market benefits from extending the network. "Oversized" SENE asset is less likely to be stranded. Residual costs met by customers.
Cost: $157/MWh for Generators B	Cost: $168/MWh	Cost: $168/MWh

Economically efficient solution	MCE proposed Rule change	EnergyAustralia's modifications
and C. Cost: $112/ MWh for generator A		(Customer pays $42/ MWh)
Customer pays $0	Customer pays $2.8 million p.a until new generation connects	Customer pays $2.8 million p.a until new generation connects
Scenario 5 - Connection of 80MW of generation capacity within zone		
New generator pays for the augmentation of the network.	20 per cent of asset remains under-utilised Subject to clarification by the AEMC, augmentation potentially funded by load customers.	20 per cent of asset remains under-utilised Generators would pay cost reflective prices for augmentation of the network.
Cost: $141/MWh for Generator D Cost: $157/MWh for Generators B and C Cost: $112/ MWh for Generator A	Cost: $136/MWh	Cost: $136/MWh
Customer pays $0	Customer pays $2.5 million p.a for remainder of asset's life	Customer pays $0.75 million p.a for remainder of asset's life

The following table demonstrates that customers pay 30 per cent of the costs of the total recovery amount for the SENE asset. This would be even higher if NPV analysis was undertaken.

Year	Cost (SENE)	Gen A	Gen B	Gen C	Gen D	Customers	Gen A-D
MW	100	5	5	15	55	n/a	80
1	$3,726	$161				$3,564	$161
2	$3,726	$161				$3,564	$161
3	$3,726	$161	$186			$3,378	$348
4	$3,726	$161	$186			$3,378	$348
5	$3,726	$161	$186	$559		$2,819	$907
6	$3,726	$186	$186	$559	2049	$745	$2,981
7	$3,726	$186	$186	$559	2049	$745	$2,980
8	$3,726	$186	$186	$559	$2,049	$745	$2,981
9	$3,726	$186	$186	$559	$2,049	$745	$2,981
10	$3,726	$186	$186	$559	$2,049	$745	$2,981
11	$3,726	$186	$186	$559	$2,049	$745	$2,981
12	$3,726	$186	$186	$559	$2,049	$745	$2,981
13	$3,726	$186	$186	$559	$2,049	$745	$2,981
14	$3,726	$186	$186	$559	$2,049	$745	$2,981
15	$3,726	$186	$186	$559	$2,049	$745	$2,981
16	$3,726	$186	$186	$559	$2,049	$745	$2,981
17	$3,726	$186	$186	$559	$2,049	$745	$2,981
18	$3,726	$186	$186	$559	$2,049	$745	$2,981
19	$3,726	$186	$186	$559	$2,049	$745	$2,981
20	$3,726	$186	$186	$559	$2,049	$745	$2,981
21	$3,726	$186	$186	$559	$2,049	$745	$2,981
22	$3,726	$186	$186	$559	$2,049	$745	$2,981
23	$3,726	$186	$186	$559	$2,049	$745	$2,981
24	$3,726	$186	$186	$559	$2,049	$745	$2,981
25	$3,726	$186	$186	$559	$2,049	$745	$2,981
26	$3,726	$186	$186	$559	$2,049	$745	$2,981
27	$3,726	$186	$186	$559	$2,049	$745	$2,981
28	$3,726	$186	$186	$559	$2,049	$745	$2,981
29	$3,726	$186	$186	$559	$2,049	$745	$2,981
30	$3,726	$186	$186	$559	$2,049	$745	$2,981
31	$3,726	$186	$186	$559	$2,049	$745	$2,981
32	$3,726	$186	$186	$559	$2,049	$745	$2,981
33	$3,726	$186	$186	$559	$2,049	$745	$2,981
34	$3,726	$186	$186	$559	$2,049	$745	$2,981
35	$3,726	$186	$186	$559	$2,049	$745	$2,981
Total	**$130,406**	**$6,396**	**$6,148**	**$17,326**	**$61,477**	**$39,060**	**$91,346**

8. Conclusions

The examples reveal the following observations:

- There is a 'gap' in the existing planning arrangements. There would be benefit in AEMO undertaking analysis which identifies renewable zones that are likely to provide long term benefits to customers. This would limit (partial) customer funded extensions to circumstances where there is a potential failure with the existing regulatory framework.
- The existing framework may provide disincentives for small renewable generators to connect to the shared network. However, in the example:
  - There is no compelling case to demonstrate that an extension of the network will result in 'lower delivered costs' of renewable generation faced by customers. This would need to be subject to analysis of market benefits as envisaged by our proposal to apply the regulatory test to the investment.
  - It is more cost effective for Generator A generator to bypass the SENE framework and connect to a local low voltage network - this situation is more likely in a distribution network.
- The concept of building an extension of the network to connect clusters of renewable generation (either through the SENE framework or extension under the regulatory test) will lower the connection costs for generators. However, in doing so:
  - There are high short term costs to the consumer, until expected generation connects (up $399/MWh with the AEMC proposal)
  - There are clear risks of asset stranding (paid for by the customer) if expected generation does not connect. In this example, the costs of asset stranding is about $23 million of the $130 million investment.
  - The total delivered costs in this example are still quite high ($133/MWh) even if full capacity is assumed. There would need to be some analysis to suggest that these costs are lower than what would have occurred if alternative sources/ areas of renewable generation were connected to the grid under the existing framework.
- Given these costs and risks, there needs to be safeguards for consumers to ensure that extensions of the network lead to long term customer benefits. In this respect, EnergyAustralia's suggested modifications to the network are more preferable than the SENE framework:
  - AEMO is the appropriate body to be accountable for identifying areas where there is a degree of certainty that customers will benefit from connecting the renewable zone.
  - Under EnergyAustralia's approach, the regulatory test is used to assess whether there are market benefits from the extension of the network, when no such test exists under the SENE framework.
  - EnergyAustralia's approach includes a minimum threshold to ensure that extreme stranding risks are minimised. For example, if Generators C, D and E did not connect, customers would pay in excess of $100 million over the SENE's life, without getting any benefits from that investment.
- EnergyAustralia's suggested approach results in minor modifications to the existing framework, and is therefore less administratively complex than the SENE framework. This includes:
  - There is no requirement for an additional connection regime, as the applicant would seek connection under the existing process. This would avoid issues such that may arise in the case of Generator A, who may be forced to connect under the SENE framework, despite having a lower cost and more timely connection option.

- The regulatory test already provides for 'least cost' design planning meaning there is no need for a duplicative regulatory instrument through the SENE Planning report.
- Charging arrangements can use existing Chapter 6 processes, and the pricing Rules will allow for 'cost reflective' recovery from generators and customers. This is contrasted with the proposed SENE Rule which includes complex charging arrangements in Chapter 5 of the Rules, including 5 year mini-building block determinations for each SENE asset.

▪ Classifying the asset as providing prescribed/direct control (standard) services will enable administratively simpler regulatory arrangements and cost reflective pricing. This is because the asset becomes subject to the AER's building block assessment and incentives, and the pricing Rules in Chapter 6. Further, classifying the asset as providing prescribed/ direct control services will:
  - Provide incentives for efficient connection of load to the SENE. This is more likely to occur in a distribution context.
  - Provide a simpler mechanism for cost recovery.

▪ Minor amendments to the Rules would be required under EnergyAustralia's example, including;
  - New planning role for AEMO to identify areas of renewable generation that are likely to lead to customer benefits if connected through an extension of the shared network.
  - Potential minor changes to the regulatory test to clarify the assessment process for calculating whether an extension of the network to meet generation areas will result in market benefits.
  - New pass through provisions for distributors to ensure that they can recover the capital and operating costs through regulated charges during a regulatory control period, if the costs have not been included in the building block determination.
  - The AEMC may need to clarify that clause 6.1.4 of the Rules (which prohibits a DNSP from charging DUOS for the export of energy) does not act to prevent a DNSP from including regulated network charges for a generator for its contribution to the extension and augmentation of the network. We consider that the preferred view, in this case, is that an NSP is entitled to charge a generator for use of system charges as part of its regulated network charges, in accordance with clause 5.5(f)(3) of the Rules.