14 November 2008

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**ENA, Scoping Paper, October 2008-Reference EMO 0001**

Dear Dr Tamblyn

The Energy Networks Association (ENA) welcomes this opportunity to respond (see Attachment) to the Australian Energy Market Commission's (AEMC) Scoping Paper - *Review of Energy Market Frameworks in light of Climate Change Policies* of 10 October 2008.

ENA strongly supports the AEMC Review process to assess what needs to be done to ensure energy markets are able to facilitate the realisation of the Australian Government climate change policy objectives.

In considering its response to the AEMC Scoping paper ENA has carefully assessed both the issues covered in the paper and whether there are matters that may have been omitted. Overall ENA is comfortable with the 8 Issues presented but believes that the Scoping paper's coverage should be extended to dealing with the impact of the Government's climate change policies on risks relating to demand, cost and price volatility arising from direct and indirect impacts of the pending Carbon Pollution Reduction Scheme (CPRS) and the expanded national Renewable Energy Target (RET).

As the Scoping paper deals at length with the risks associated with the increased incorporation of new intermittent generation sources into the national grid ENA has based a substantial part of its response from its recently completed *Embedded Generation Issues ENA Policy Discussion Paper.* Our Demand Management and Embedded Generation Committee applied its considerable expertise to compile what is a comprehensive coverage of regulatory, contractual and technical issues that need to be addressed to provide the best chance to attain the Government's RET objective while meeting its broader energy policy goals. The paper is enclosed with our submission to assist AEMC with its deliberations over the next 12 month.

ENA looks forward to working closely with the AEMC on its Review over the next 12 month. For further information please contact Bill Layer, Research Officer, ENA on telephone (02) 6272 1555.

Yours sincerely

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**THE AEMC SCOPING PAPER – REVIEW OF ENERGY MARKETS IN LIGHT OF CLIMATE CHANGE POLICIES**

ENA Submission

14 November 2008

**Key Messages:**

- **ENA is supportive of the AEMC *Review of Energy Markets in the light of Climate Change* as it provides a process that will enable the national energy legislation and regulation to evolve in tandem with the design of CPRS and the implementation of the enhance MRET.**
- **ENA shares AEMC concerns relating to reliability risk associated with some alternative energy sources, and the willingness of investors to commit to developments under the CPRS and MRET**
- **Under the current regime governed by 5 year regulatory reset periods the issue of whether there is sufficient flexibility within the NER to cope with the impact of climate change policies needs to be examined as part of the AEM Review.**
- **ENA supports a regulatory approach which places non-network options, such as EG, on an equal footing with established network augmentation approaches.**
- **The regulatory regime should ensure full cost recovery in relation to investments in energy infrastructure developed in response to climate change.**

**Executive Summary**

The Energy Networks Association (ENA) welcomes this opportunity to respond to the issues and questions raised in the Australian Energy Market Commission (AEMC) Scoping Paper – *Review of Energy Markets in Light of Climate Change Policies* issued on 10 October 2008.

ENA is the peak national body for Australia's energy networks. ENA represents gas distribution and electricity network businesses on economic, technical and safety regulation and energy policy issues.

ENA strongly supports the AEMC efforts to assess what needs to be done to ensure energy markets are able to facilitate the realisation of the Australian Government climate change policy objectives.

Further, ENA is broadly comfortable with issues canvassed in the Scoping Paper including, the risks associated with the increased incorporation of new intermittent generation sources into the national grid, line losses and increased congestion, Notwithstanding the above, ENA wishes to make to following general observations:

- The Scoping Paper tends to be transmission focussed with relatively little attention to the implications for the energy distribution sector. This submission puts forward a number of suggestions for the AEMC's consideration that identify issues impacting on energy distribution networks;

- As a general principle, ENA envisages that the AEMC will only recommend the introduction of additional regulation where the market has failed, is likely to do so, or has been deemed to be unlikely to achieve the Government's climate change policy objectives. As long as the market for generation development is structured in the most efficient way then up to the market to sort it out;

- The industry is developing a number of measures such as the Short Term Trading Mechanism (STTM) being developed via the Gas Market leaders Group. Initiatives such as these should be allowed to be implemented and bedded down before any assessment of further regulatory or market intervention.

ENA believes that one of the major omissions in the Scoping paper is the lack of coverage given to the potential impact on consumer demand arising from:

- The roll out of new technologies, in particular, smart meters and the related development of the smart network; and

- The impact of rising energy prices partly driven by the Carbon Pollution Reduction Scheme (CPRS) and the enhances Mandatory Renewable Energy Target (MRET)

Another omission that AEMC needs to address is network concerns over the capability to recoup costs including:

- Costs relating to infrastructure that is introduced to facilitate either connection of CPRS/MRET related assets or infrastructure items to lower the carbon footprint; and

- The impact of carbon permit costs arising from the CPRS on regulated energy network businesses. Under the CPRS the price of carbon permits is likely to experience periods of volatility with consequent impacts on input costs for network operators. Whether the current 5 year reset period for price determination under the National Electricity Rules (NER) is flexible enough when step changes in the cost of materials used to deliver energy occur frequently needs to be investigated.

Overall, ENA is supportive of the Governments carbon mitigation policy and the vital role foreseen for embedded generation. In this context ENA has and continues to employ considerable resources to identify the impediments in the National Energy Mark (NEM) relating to adaptation and mitigation to climate change. In February 2008 ENA released its *Demand Management Regulatory Policy Framework Paper*. At that time it also initiated an investigation into the issues impacting on the incorporation of embedded generators into the network which is now completed and forms part of this Submission (see enclosed *Embedded Generation ENA Policy Framework Discussion Paper*).

**Background**

This submission responds to the Australian Energy Market Commission (AEMC) Scoping Paper – *Review of Energy Markets in Light of Climate Change Policies* issued on 10 October 2008.

ENA is the peak national body for Australia's energy networks. ENA represents gas distribution and electricity network businesses on economic, technical and safety regulation and national energy policy issues. Energy network businesses deliver electricity and gas to over 13 million customer connections across Australia through approximately 800,000 kilometres of electricity distribution lines. There are also 76,000 kilometres of gas distribution pipelines. These distribution networks are valued at more than $40 billion and each year energy network businesses undertake investment of more than $5 billion in distribution network operation reinforcement, expansions and greenfields extensions. Electricity transmission network owners operate over 42,000 km of high voltage transmission lines, with a value of $10 billion and undertake $1.2 billion in investment each year.

**General Comments**

ENA is supportive of the AEMC Review of Energy Markets in the light of Climate Change as it provides a process that will enable the national energy legislation and regulation to evolve in tandem with the design of CPRS and the implementation of the enhance MRET.

In terms of the AEMC's Scoping Paper, ENA accepts that the 8 issues presented deal with matters that need to be covered in any assessment of the impact of climate change on the National Energy Market (NEM). In particular, ENA shares AEMC concerns relating to reliability risk associated with some alternative energy sources, and the willingness of investors to commit to developments under the CPRS and MRET.

Overall ENA supports the increased use of embedded generation (EG) as a cost effective strategy for providing network support for the implementation of an efficient carbon mitigation strategy. In recognition of the role of EG the ENA has completed a discussion paper which canvasses the issues that need to be resolved to successfully integrate EG into the grid. The paper, *Embedded Generation ENA Policy Framework Discussion Paper* (Attached) has been used extensively in responding to the questions raised in the AEMC Scoping paper as set out in the next Section.

With respect to the Scoping papers coverage ENA's view is that the Scoping paper has omissions in its coverage. Namely:

***Demand Risk Issues for Network Service Providers***

The impact of the CPRS on retail prices is likely to have significant impacts on consumer demand and consequently on the volume of energy flowing through the network. Specifically, step changes in energy demand are likely to occur more frequently and over short periods as the carbon price varies. This outcome is made more likely with the implementation of smart metering and the evolution of smart networks which will facilitate more rapid consumer responses to changes in energy markets.

Where network businesses are covered by regulated price caps a drop in energy demand will have a significant impact on returns with consequences for investment decisions. Under the current regime governed by 5 year reset periods for price determinations, the issue of whether there is sufficient flexibility within the NER to cope with the impact of climate change policies needs to be examined as part of the AEM Review.

***Impact of CPRS/MRET on energy network input costs***

The pervasive impact of the CPRS though carbon permit costs flowing on to energy prices and therefore on to all material inputs to the construction of network infrastructure will lead to quantum increases in the cost of providing energy network infrastructure. Specifically, network businesses are highly dependent on products involving energy intensive manufacturing processes such as aluminium conductors, steel pipes and pylons as well as other metal and ceramic inputs.

For the electricity distribution sector there are also cost increases related to the CPRS impact on sulphur hexafluoride used in some electrical components. Gas distribution businesses, in addition to the increase costs of materials will also be liable under the CPRS of fugitive gas emissions.

As with demand risk above, the potential volatility of carbon permit prices could lead to significant cost changes for network businesses. This is of particular concern in cases where the CPRS commences operation within a regulatory period as it will not be accounted for in the price received by network businesses.

As gas networks are exposed to trading risk under the CPRS this needs to be recognised by the regulator. Some gas distribution businesses have contract or access arrangements which only pass through costs associated with a change in a tax event, which may not allow businesses to recover permit costs. It would provide certainty to the industry if the AEMC/AER made clear, through an appropriate mechanism, that the introduction of the CPRS would be deemed to meet the criteria for a change in tax event. This would ensure a more efficient outcome as opposed to those businesses relying upon re-opening of their respective Access Arrangements - a protracted and costly approach.

Electricity network businesses can only recover these cost changes if the regulatory framework enables timely pass-on to customers through increased prices. However, unless the current regulations for determining price setting are made to be more flexible there is a material risk that increased input costs will not be fully recoverable by network service providers. AEMC needs to consider this matter as any perceived increase in risk that costs will not be recovered will have a negative impact on investment in infrastructure.

There is also the matter of full cost recovery of investments in infrastructure required for the connections of CPRS/MRET related assets. In the absence of timely cost recovery adjustments via a more responsive regulatory arrangements the certainty needed to bring forward the funds crucial to the success of the Governments Climate Change strategy would be put in jeopardy.

**RESPONSES TO QUESTIONS**

**<u>ISSUE 1. Convergence of gas and electricity markets</u>**

**Q1. How capable are the existing gas markets of handling the consequences of a large increase in the number of gas-fired power stations and their changing fuel requirements?**

*ENA Response*

ENA expects that more gas fired electricity generators will be directly connected into the gas distribution network as the CPRS ramps up. We believe energy networks will be able to meet the increased demands to connect these new gas based embedded generators into distribution networks provided full cost recovery is realised.

**Q 2. What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such differences be?**

*ENA Response*

No comment.

**<u>ISSUE 2. Generation capacity in the short term</u>**

**Q3. What are the practical constraints limiting investment responses by the market?**

*ENA Response*

Not relevant to ENA [questions relating to this issue apply to the power generation sector]

**Q4. How material are these constraints, and are they transitional or enduring?**

*ENA Response*

Not relevant to ENA

**Q5. How material is the likelihood of a need for large scale intervention by system operators? How likely is it that this will be ineffective or inefficient?**

*ENA Response*

Not relevant to ENA

**<u>ISSUE 3. Investing to meet reliability standards with increased use of</u>**

**<u>Renewables</u>**

With growth in EG in the distribution network there will be a requirement to have increased monitoring and flexibility in network configuration due to changing generation patterns. This will require increased use of monitoring, line regulators and remote switching equipment and in increased complexity in both planning and operating the network.

In the transition period where there is a low level of EG in the network resulting in insufficient diversity of generation types and locations, the network will often need to be designed and operated assuming little contribution from this generation in order to ensure reliability of supply.

**Q6. How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?**

*ENA Response*

ENA believes that there is a material risk of a reduction in reliability should a significant portion of additional generation requirement come from intermittent sources such as wind and solar power.

Distribution businesses have measures in place to monitor customer service levels and incentives to improve these as required. Therefore while there will be some issues associated with new EG relating to reliability of supply distributors will be required to contract with some EGs, as they currently do, for additional network support where this is more cost effective than a network solution. There will potentially be a significant number of contracts for network support and this will increase complexity in the both network and business operations.

System voltage fluctuations and power surges affect customer reliability and supply quality. The level and type of generation will determine the degree of complexity. A significant component of EG in the southern areas of Australia will mainly come in the form of wind generation which has a variable and unpredictable generation source. The variability of this generation type makes forecasting generation complex and together with customer load variability means the balancing of the 'generation versus load' equation difficult. In the past this task has been carried out at a Transmission Network Service Provider (TNSP) level heavily influenced by stable base load generation plants. The EG being introduced into the distribution network is another variable component entering into the equation. A clear mechanism and agreement on the planning and operational responsibilities need to be established.

As part of system security there are 'under frequency' and 'under voltage' customer load shedding schemes in operation. The European experience in 2003 showed that the standard load shed plan in place was able to maintain security of the network but the decentralised EG affect was not expected and finally provoked a system blackout. The EG being connected is a collection of large generation schemes 'riding through' system disturbance and medium, small and micro generation schemes disconnecting from the network. There is a requirement for more in depth understanding and co-ordination between the Distribution Network Service Providers (DNPS's), TNSP's and the generators to consider the impact of the increasing EG installations.

Where a "network augmentation" solution is displaced by, for example, a third party EG solution to address a customer load at risk scenario, there is inherent risk to the customers should this EG cease operation after some period of operation or is designed to a lesser level of reliability[1].

DNSP's have an obligation to consider alternative solutions in a fair and reasonable manner. An EG solution could be deemed to be a fair and reasonable alternative to a line augmentation. The DNSP is exposed and subject to "service target performance incentives" for supply to their customers. Although a third party EG owner could be subject to an availability performance target the operation of the EG business remains independent of the DNSP. This means that the DNSP cannot have total control of assets providing the electricity service to their customers and is exposed to any penalty should the EG fail to comply with its performance targets.

A key consideration is the assessment of the needed and delivered supply reliability and how this may be affected by the relative availability of the network, generator and combination supply arrangement. For smaller and non critical loads “N” reliability may be acceptable to the DNSP whilst “N-1” (requiring full redundancy) may be needed to service larger and/or sensitive connections or meet licence compliance conditions.

The expected reliability of a supply system can be indicated from accepted availability figures and used in association with repair time allowances to determine the suitability of a proposed supported network (for details see Attachment D of enclosed *Embedded Generation ENA Policy Framework Discussion Paper*).

**Q7. What responses are likely to be most efficient in maintaining reliability?**

**Efficient Responses for Maintaining Reliability**

The ENA considers that the speed of response from other generation or load reduction measures to the loss of intermittent generation is likely to be the key to efficiently maintaining reliability.

Investment in communications, protection and control systems to allow non-essential loads to be removed promptly, in response to a loss of generation, would assist in maintaining reliability and allow the amount of intermittent generation to be increased significantly. This could include short term interruptions to, or a reduction in energy use from, water heating, air-conditioning, refrigeration and pumping.

**Impacts on reliability and performance incentives**

ENA submits that the NER should ensure that network businesses are not penalised through performance incentives when an alternate non-network solution, such as renewable generation with a high reliability risk profile is implemented.

[1] Due to cost considerations, an EG proponent may choose to install a single larger generating unit in lieu of two smaller units of equivalent capacity, which in inherently more reliable.

ENA's view is that consideration needs to be given to the appropriate mechanisms to manage reliability risks imposed by intermittent generation, so that network businesses are not disadvantaged.

Any risk to DNSP's obligations to provide network services and ensure power quality to other network users posed by connection and operation of EG with intermittent power characteristics should be covered by appropriate regulatory requirements imposed on the generators involved. As a result network providers would not be penalised through 'performance incentives' when a non-network solution is implemented in lieu of network augmentation.

**Power Quality**

All connecting EGs have a responsibility to comply with the DNSP's requirements and as a minimum maintain the existing power quality conditions on the network as reflected in their contractual arrangements.

Fault levels are a technical aspect of a network determined by design and asset capability of both the network and the customers connected.

Connection of EG to the network can only be accommodated when the connection of the generator does not exceed the allowable fault level contribution as determined by the network service provider. Due to improving network utilisation and connecting generation electrically close to the distribution assets, the technical requirement to operate the network below fault level limits is becoming more difficult and hence more expensive to connect EG and maintain a safe working practice. This raises the question of financing the infrastructure augmentation to allow connection of additional generation. The current industry practice is that the connecting party that causes the fault limit to be exceeded pays the total cost to augment the infrastructure. In some situations these costs can result in financial barriers to proceed with connecting the generator.

**ISSUE 4. Operating the system with increased intermittent generation**

**Q8. How material are the challenges to system operations following a major increase in intermittent generation?**

*ENA Response*

ENA submits that the current regulations do not adequately deal with the challenges posed by a major increase in the presence on intermittent generation into the NEM. Lack of information regarding embedded generators (units supplying less than 5 MW are not required to be registered with NEMMCO) and generator dispatch are likely to present greater challenges as the number of smaller, intermittent generators are connected to transmission and distribution networks.

These challenges are posed to network operations particularly in relation to reliability and safety performance.

Transmission and distributor businesses are subject to “Service Target Performance Incentives” for supply of electricity to customers. This means that network service providers are exposed to penalties for any shortfalls in their performance regarding reliability and quality of power supplied to customers arising as a consequence of EG failure to meet performance requirements.

ENA’s position is that DNSPs should not be penalised through 'performance incentives' when an alternative non-network solution with a higher risk profile is implemented in lieu of a network augmentation. ENA’s view is that there needs to be consideration of mechanisms in the NER to address this issue.

**Q9. Are the existing tools available to system operators sufficient, and if not, why?**

*ENA Response*

There will be additional complexity and costs associated with the management of hazards and public health and safety risk posed by the increased operation of renewable energy generation connected to distribution networks.

The network protection requirements for the connection of EGs are necessary to ensure that the operation of the generating units do not:

1. Increase public health and safety risks;
2. Cause any reduction in power transfer capability of the network due to reduced rotor angle stability; reduced frequency stability; or reduced voltage stability;
3. Cause any increased need for load shedding in the event of an unplanned trip of the generating unit due to the rate of change of frequency; magnitude of frequency excursions; active power imbalance; reactive power imbalance; or displacement of reactive power capability; and
4. Adversely affect the DNSP or other users caused by transients relative to the level that would be applicable if the EG unit were not connected.

The degree of potential impact on the network is directly proportional with the size of generating capacity of the EG connecting to the network.

For example, a mini EG (See Chapter 4 of *the Embedded Generation ENA Policy Framework Discussion Paper* enclosed with this submission) such as a 3 kW to 5 kW photovoltaic system is unlikely to reduce or limit the power transfer capability of a network or cause any increased need for load shedding in the event of an unplanned disconnection from the network under contingency conditions resulting from the operation of protection equipment. In the case of the latter, the generating capacity lost is well within the capability of the existing network and generating capacity to absorb and will not result in the need for any load shedding. As such, the network is unlikely to detect any material voltage or frequency variations. The primary concern for the connection of micro EGs (less than 2kW) would be the increased risk to public health and safety due to the potential for islanded operation, although for inverter connected systems this risk is relatively low.

For small EGs and above connected to the distribution network, the risk of islanded operation following a network outage is relatively high. The public health and safety risks of islanded operation for EGs of this size is significant, hence protection against islanded operation is essential.

In the case of larger EGs in the order of 30MW and above, depending on the operating characteristics and connection point in the network, momentary network disturbances such as short-circuit faults which may occur in geographically remote but electrically proximate locations can result in voltage and synchronous instability of the power system causing widespread system failure. In such situations, network protection upgrades may be required at points within the network that is geographically remote but electrically proximate from the EG's point of connection to ensure that short-circuit faults are cleared within more onerous critical fault clearance times. Moreover, additional or more stringent local protection at the point of connection may be required to detect and mitigate the risks of transient voltage dips or frequency excursions.

**Q10. How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient?**

*ENA Response*

See Grid Australia response

**Q11. How material are the risks associated with the behaviour of existing generators, and why?**

*ENA Response*

See Grid Australia response

**<u>ISSUE 5. Connecting new generators to energy networks</u>**

**Q12. How material are the risks of decision-making being "skewed" because of differences in connection regimes between gas and electricity, and why?**

*ENA Response*

In Victoria connecting generators pay all costs associated with the new connection including network augmentation requirements for both electricity and gas and therefore there should not be an issue with skewed decision making from a connection point of view.

**Q13. How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiation?**

*ENA Response*

There is a need to establish clarity in EG connection contracts and operating processes. However, in doing this it is important to note that the connection process will vary with the class of EG to be connected (see Chapter 7 of the attached *ENA Embedded Generation ENA Policy Framework Discussion Paper*)

The potential for regulation to provide for establishment of processes for conveying opportunities for EG development and the intention of EG investors as well as for the application and acceptance of EG need to be assessed. There is also a need to ensure that the relationship between network providers and EG owners provides for clarity as to the process for application and acceptance of obligations, liabilities, and sanctions.

Contract clarity also needs to be established with respect to the provision of network services to the EG owner taking account of the classification of the EG, the reliability of supply and the magnitude of network support required, if applicable.

ENA supports the adoption of a standard connection process for EG installation generally. This is consistent with its commitment to having a common procedure and uniform documentation for any EG connection proposal in the interest of simplifying the connection process and not as an indication of an automatic right to connect. This support should not be seen as an endorsement of the concept of providing the EG with an automatic right of connection.

A separate but related issue is the so called "first mover problem", where potentially larger generators have an incentive to delay commitment to invest in the hope that another investor will cover all (most) connection costs by initiating the first generator installation. This incentive to "free ride" is recognised as a market failure in the *Garnaut Climate Change Review Report* (September 2008) which has the potential to delay or stop the deployment of renewable generation. ENA recommends further consideration on this issue.

Overall co-ordination although complex should be paramount to facilitate cost sharing synergies across the whole EG connection process. The distribution businesses are best positioned to facilitate a co-ordinated planned approach to enable cost saving strategies going forward which will benefit proponents and the customer who ultimately funds the developments.

**Q14. Are the rules for allocating costs and risks for new connections a barrier to entry, and why?**

*ENA Response*

The NER connection procedure outlines the sequence of submissions and responses required of the proponent and the DNSP, moving from an initial connection enquiry, to an application, an offer to connect by the DNSP and concluding with signed Connection Agreement based on the offer.

Whilst this process presents a logical sequence of connection activities, ENA submits that it has some inherent limitations in that:

- the prescribed response times are unrealistically short taking in to account those actually needed to complete many of the activities associated with a connection project;
- there is undue emphasis on the Application step as the key stage, and
- more recognition needs to be given to the need for consultation at the enquiry stage to identify issues associated with a proposed connection and allow the development of an "agreed project" which is reasonable and workable in terms of both DNSP network capability and proponent network service requirements.

Without an interactive approach to confirm a workable project proposal following the submission of a Connection Enquiry, there is no surety that a workable "offer to connect" will result from the present NER obligation for an "offer to connect" to be made against a submitted "connection application".

**Issue 6. Augmenting networks and managing congestion**

### Q15. How material are the potential increases in the costs of managing congestion, and why?

*ENA Response*

Currently EG owners' connection costs only reflect the costs of connecting them directly to the network ("shallow" costing) plus some negotiated additional costs relating to shared network augmentation. They are not generally exposed to the cost of increased congestion resulting from EG investment decisions ("deep" costing). Therefore a significant increase in congestion arising from a major shift to renewable energy generation could have a material cost impact on network businesses.

### Q16. How material are the risks associated with continuing with an "open access" regime in the NEM?

*ENA Response*

ENA submits that the technical requirements outlined in the attached *Embedded Generation ENA Policy Framework Discussion Paper*, Chapter 6) indicate that all but the micro and some small EG connections can impose the need to investigate the impacts of the proposed connection on the network performance and the capacity of the network to provide the required connection services.

In the longer term, the wide spread adoption of micro/mini EG (such as a PV array on every roof) could make it necessary to have a record of the number, capacity and location of every

EG installation. Such records would allow the network operating, supplied power quality and safety performance affects of what could become substantial and increasing aggregated capacity to be assessed and monitored if/as needed.

Since the introduction of the Commonwealth Government's Photovoltaic Rebate Program (PVRP) and at the state government level feed-in tariffs and renewable energy buyback scheme (REBS), there has been marked increase in the uptake of micro/small EG systems. This trend is likely to continue or accelerate going forward, given the impending introduction of the CPRS and intense debate on climate change.

As such, careful consideration needs to be given to the definition of the capacity and characteristics of any plant to be given the right of automatic connection and the "record keeping" associated with their installation to minimise the impacts on network safety, reliability and security.

**Q17. How material are the risks of contractual congestion in gas networks and how might they be managed?**

*ENA Response*

If there is no capacity then the required capacity augmentation is paid for by the connecting party. These could be substantial depending on the location but this is sending the correct signal to new generators.

**Q18. How material is the risk of inefficient investment in the shared network, and why?**

*ENA Response*

See Grid Australia response.

**Q19. How material is the risk of changing loss factors year-on-year?**

*ENA Response*

Until the Australian Energy Regulator (AER) issues a national guideline on how distribution businesses are to calculate loss factors it is difficult to comment on this issue.

However we believe that distributors will experience a change in loss factors but this should be small as EG installations rise.

It is important that the Distribution loss factors and the Transmission loss factors consider a closer link with any proposed methodology changes to ensure verification and implementation of any methodology complements and not conflicts going forward. It is worth noting that the use of forward calculations of loss factors could assist EG owners in being informed about the risk associated with change following the addition of generation to any section of the network or with a significant change to the pattern of operation of a generator.

## ISSUE 7. Retailing

The AEMC paper states that the CPRS will increase the wholesale energy costs, and possibly the prudential costs, to retailers. The paper suggests that these additional costs will need to be managed by an efficient retailer and could conceivably lead to retailer distress and exit from the market.

The cost of goods used by an electricity or gas network are expected to also increase under the CPRS as manufacturers and suppliers seek to offset their costs of acquiring permits. As this cost is passed onto the customers, the price signal is likely to lead to some demand response.

The increased costs of network charges will further exacerbate the situation for retailers. This is a significant issue for retailers where their retail prices are capped and they are unable to pass on the costs to consumers. In this context AEMC needs to ensure that appropriate and timely mechanisms exist to ensure that climate change related costs are passed to final consumers.

**Q20. How material is the risk of an efficient retailer not being able to recover its costs, and why?**

*ENA Response*

As described above, retailers and distributors need certainty for cost recovery of new or increased costs arising from the CPRS.

Regulators need to be cognisant of these cost increases and allow the costs to be passed through via a regulatory mechanism for distributors (see General Comments).

The regulatory environment also needs to allow and encourage the innovation of new products in the market and should not encourage the ongoing entrenchment of tariffs that lack cost reflectivity.

**Q21. What factors will influence the availability and pricing of contracts in the short term?**

*ENA Response*

Not relevant to ENA

**Q22. How material are the risks of unnecessarily disruptive market exit, and why?**

*ENA Response*

The Retailer of Last Resort (ROLR) processes within jurisdictions may provide for a designated ROLR in the event of a 2nd tier retailer failure. In general the ROLR process relies on the local retailer being the designated ROLR for a failed retailer that has been deregistered from the market. The market is less equipped for a local retailer failure or the failure of a local retailer involved in both fuels.

Whilst this type of an event may have a low probability of occurring, the risks of gaining funding in the current credit market, increased costs and wholesale market volatility and potentially market distortions created by regulatory environments or limited ability to gain recovery due to retail price caps may make this a higher likelihood than in the past.

Even an efficient retailer may be unable to secure the necessary additional prudential cover required in the current financial markets.

A large retail failure where the retailer was involved in both fuels could have significant ramifications on the ROLRs and the businesses/transactions that support the ROLRs.

These risks have flow on impacts to network and transmission businesses. Regulators need to recognise that these risks are increasing due to counterparty risks increasing. Regulators need to allow for increased counterparty risks as retail competition becomes more effective and retail margins are squeezed. This is a non systemic risk which needs to be factored into the WACC. Any network or transmission business has a limited number of counterparties and has very limited diversity in this risk.

**Issue 8. Financing new energy investments**

**Q23. What factors will affect the level of private investment required in response to climate change policies?**

*ENA Response*

The level of private investment in energy markets in response to climate change policies will be driven by

- o The Carbon Pollution Reduction Schemes Settings
- o Regulatory provisions applying to energy infrastructure

The Regulatory framework settings are crucial in determining whether the energy market adjust to enable balanced and coordinated investments in energy infrastructure needed to accommodate climate change. It is vital that the Regulator ensures that the regulations do not distort outcomes which could lead to a surplus in some essential energy infrastructure components while other aspects are under developed. For example, regulations favouring network augmentation will lead to under investment in non-network solutions. Alternatively, regulatory rules favouring renewable generation will lead to underinvestment in vital network infrastructure leading to congestion and power quality problems.

ENA supports a regulatory approach which places non-network options, such as EG, on an equal footing with established network augmentation approaches. Regulatory neutrality between the treatment of conventional network options and those required to respond to climate change are essential for achieving the appropriate levels of investment. It follows that national access rules should ensure that renewable energy generation connections are not subsidised by the networks.

A recent Energy Supply Association of Australia (ESAA) paper on the impact of the CPRS scheme highlighted that 5,000MW of extra capacity had been delivered over the last decade. Approximately 16,000MW would need to be built over the next decade as power stations close.[2] This is a significant challenge in terms of investment requirement but also in terms of capability to deliver. There is a risk that there may not be sufficient resources with the necessary expertise to deliver such large scale infrastructure development projects in the timeframe.

**Q24. What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost**

*ENA Response*

To ensure investment in energy market infrastructure is timely and efficient market frameworks will need to provide investors with clarity and certainty regarding the rules and the ability to manage risk while allowing for the minimum rate of return enabling a business case to support development related to climate change policy. Some areas that will need to be addressed are:

- Ensuring that the regulatory regime recognised and provides for full cost recovery in relation to investments in energy infrastructure developed in response to climate change. This includes investment in research and development including pilots and trials required to establish the viability of options to abate and adapt to climate change

- The achievement of a level of national uniformity in the definitions, requirements and conditions required for the integration of renewable energy into transmission and distribution networks.

- The establishment of clarity in regulations such as in renewable energy generation contracts covering the process for application, and the acceptance of obligations, liability and sanctions.

- Consideration needs to be given to the impact of the risks to network performance related to the increased use of renewable energy generators, and other demand management responses so that networks are not penalised for adopting non-network options. ENA submits that in the application of the Regulatory Test and in developing supply agreements, reliability performance measures need to take into account all three reliability risk measures, namely supply availability, supply risk and repair time implications.

- Allowing for, capital and operating costs for demand management projects to be treated the same as such costs associated with network energy infrastructure investment. Currently only ex post recovery of capital costs applies to demand management in contrast to ex ante capital cost recovery relating to network augmentation.

[2] Energy Supply Association of Australia, The impact of the ETS on the energy supply industry, June 2008, p86

- Provision of a mechanism(s) in the regulations to deal with the energy network revenue losses arising from the implementation of successful demand management projects whereby energy through put declines.

- The provision of nationally consistent information disclosure and planning regime for network businesses that is proportionate to the expected benefits of that regime.

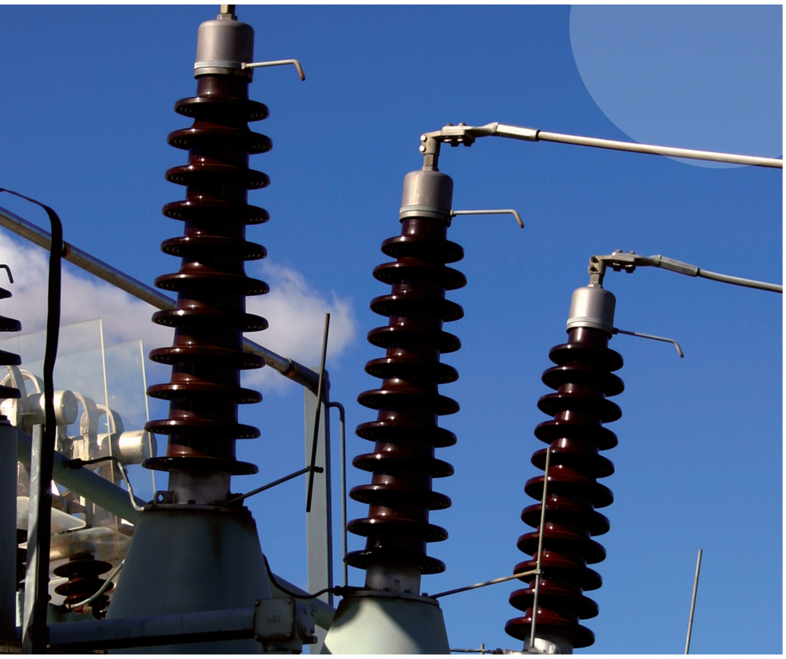
- Allow for more cost reflective structures in regulatory regimes for customers, supported by transparent community service obligations to assist those in financial hardship.

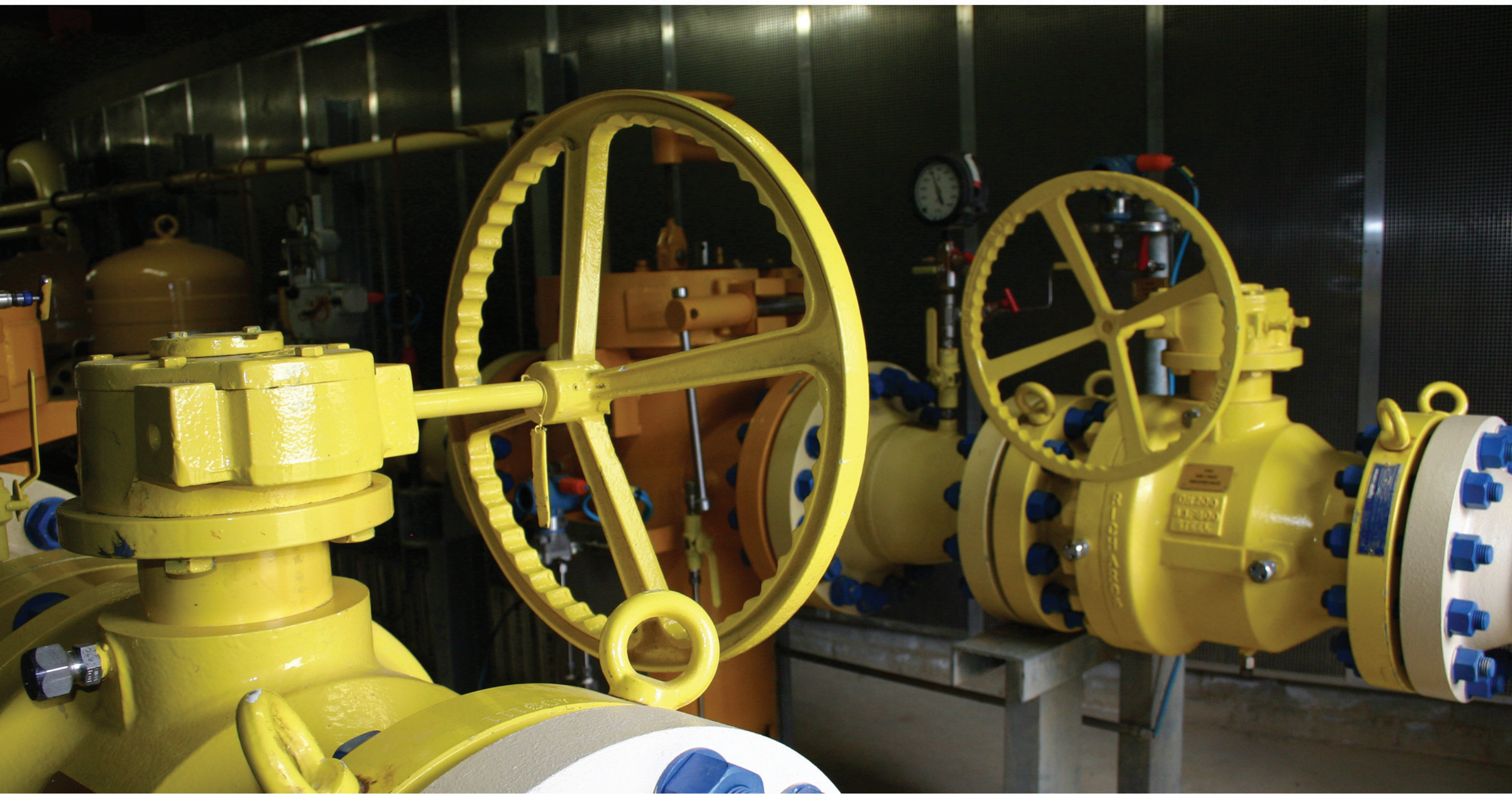
energy networks association

# Embedded Generation

## ENA Policy Framework Discussion Paper

November 2008





# Embedded Generation
# ENA Policy Framework
# Discussion Paper

# November 2008

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# Overview

**Main Messages**

- Support for the wider use of demand management by DNSPs is an important step to encouraging embedded generation. These issues are discussed in the ENA Demand Management Regulatory & Policy Framework (February 2008).
- Establishment of national access rules which ensure that embedded generator connections are not subsidised by electricity networks.
- Increased harmonisation of technical requirements, contractual arrangements, operating protocols and procedures for the connection of the smaller embedded generators across jurisdictions.
- Consideration be given to the impact of the risks to network performance related to the increased use of embedded generation so that networks are not penalised for linking such generation into the grid.

Current energy policy trends include an emphasis on cleaner energy to meet national environmental goals, including climate change abatement, has increased the pressure for incorporating increased renewable energy sources into the electricity network. This development is reflected in recent Australian Government commitments to implement a Carbon Pollution Reduction Scheme (CPRS) and an expanded national Renewable Energy Target (RET) scheme.

The enhanced RET aims to ensure that the equivalent of at least 20 percent of Australia's electricity supply is generated from renewable energy by 2020. This target poses a challenge to electricity network operators and the Australian Energy Regulator (AER) who have to find ways to incorporate significant renewable energy sources into the electricity grid without compromising energy security and safety.

An outcome of the push for more renewable energy sources in the National Electricity Market (NEM) is expected to be a significant rise in the development of embedded generation (EG).

EG refers to generators connected within the distribution network in contrast to larger power plants which are generally located at a distance from final energy consumers. EG is located in proximity to end users and typically involve a wide range of capacities (ranging from less than 1 KW to tens of MW's (or thousands of kW), technologies (from conventional induction and synchronous machines to power electronic based devices), operating characteristics and connection arrangements (from within a domestic installation to project specific substations). It can also be for a range of purposes such as supply of renewable energy, peak load reduction or the provision of network support.

Typical EG installations commonly comprise:

- Photovoltaic Systems;
- Small to large scale wind power generators;
- Hybrid renewable energy and diesel systems;
- Combined heat and power generators; and
- Micro to large gas turbines.

This policy framework paper considers the regulatory, contractual and technical issues that need to be addressed to provide the best chance to reach the government RET objective while meeting broader energy policy goals. Some 30 Key Messages have been formulated (See Summary at Attachment A) to provide guidance to policy makers, advisors and regulators.

The paper is broadly divided into four areas:

1. Setting the scene (Chapter 1 to 4);
2. Pricing (Chapter 5);
3. Technical issues (Chapter 6, 7, 10); and
4. Matters relating to contractual arrangement and operating protocols (Chapters 8, 9 and10).

Major issues identified in this paper relate to:

**Furthering national consistency**

The paper points to a number of inconsistencies between jurisdictions in relation to EG tariffs policies, technical requirements for generators under 30MW, procedures for the connection of, and the contractual arrangement for micro, mini and small and medium EG.

ENA supports moving towards a nationally consistent approach to the above issues where practicable. This would include the harmonisation of tariff policies, development of common connection processes, including common procedures, development of uniform documentation, information collecting procedures, contractual arrangements and operational protocols.

Further, increased standardisation of technical (for example: protection) requirements across network providers is highly desirable as it allows for EG products to be connected to different parts within a particular network and in different networks. This would reduce the costs relating to the manufacture of variants to the one EG product or the need for modifications to the product.

## A requirement for full cost recovery and cost reflective pricing

As a general principle ENA believes that generators should pay the full cost of connection to the electricity distribution network. The regulator needs to be vigilant to ensure that those not accruing direct benefits from the generation are not forced into cross subsidising the generation connection.

ENA gives in principle support to the application of use of system charges and recommends that the Australian Energy Market Commission (AEMC) consider this issue further. This is because DNSPs are entitled to be paid by users of their networks, irrespective of whether they are receiving energy from or sending energy to the system. All network users should be required to pay their share of the use of the network.

The paper finds no rationale for the requirement that network service providers make avoided use of system payments to EG owners. While calling for the removal of these charges, ENA nevertheless recognises that there is a role for network support payments to network support EGs and demand management providers. This is justified where non- network solutions are demonstrated to be the most efficient means of alleviating a network constraint.

The growing number of generator types, their different operating characteristics and the wide range of capacities creates a need for more complex communication infrastructure to facilitate safe, secure and reliable operation of EGs.

ENA notes that there is a need for supervisory, control and data communication between the EG operator and the network service provider, particularly in the case of larger EGs, and that this cost should be recognised. Another cost that needs to be taken into account is anti "islanding" equipment. Islanding occurs where a part of the electricity network becomes isolated leaving it to be supplied by the local generator. This can result in safety risk and supply quality issues where the EG installation is not intended and designed to take over the load supply.

## Issues relating to the application of the Regulatory Test

ENA believes that, when considering the characteristics of EGs as part of Regulatory Test options analysis, DNSPs need to have regard for the availability and reliability of EGs and also the associated supply risk and repair times. In this context, ENA's view is that there is a need to consider options for adopting a regulatory approach which places non-network options, such as EG, on an equal footing with established network augmentation approaches in terms of delivering the needed performance requirements

## Need for consultation between stakeholders

The processes and outcomes under the current NER connection procedures do not reflect the need for what can be extensive consultation and preliminary network assessments to give certainty that a workable EG proposal and connection exists.

Without an interactive approach to confirm a workable project proposal following the submission of a Connection Enquiry, there is no surety that a workable "offer to connect" will result from the present NER obligation for an "offer to connect" to be made against a submitted "connection application".

ENA's view is that facilitation of efficient and effective incorporation of EG requires an improved understanding and co-ordination between network service providers and generator proponents particularly with respect to the consideration of the impact of EG during system operation. This interactive approach is essential to confirm that a workable EG project proposal exists following a connection enquiry.

**Management of Risk**

Transmission and distributor businesses are subject to "Service Target Performance Incentives" for supply of electricity to customers. This means that network service providers are exposed to penalties for any shortfalls in their performance regarding reliability and quality of power supplied to customers arising as a consequence of EG failure to meet performance requirements.

ENA's position is that DNSPs should not be penalised through 'performance incentives' when an alternative non-network solution with a higher risk profile is implemented in lieu of a network augmentation.

ENA submits that any risk to a DNSP's obligations to provide network services and ensure power quality to other network users posed by the connection and operation of EGs should be covered by an appropriate requirement or penalty on the EGs involved. As a result network providers would not be penalised through 'performance incentives' when a non-network solution is implemented in lieu of network augmentation. ENA's view is that there needs to be consideration of mechanisms to address this issue.

**Safety cannot be compromised**

Electricity networks are characterised by extensive distributed assets throughout the public domain such as powerlines, substations and underground cables. EG assets will add to the hazards and risks posed by the operation of these energy assets in the public domain.

ENA released a *Proposed National Framework for Electricity Network Safety* in July 2008 as the recommended approach to national electricity network safety regulation. In having an industry wide approach, the safety requirements established for each of the distribution network service providers can not be compromised for any of the different classes of EG.

A list of the key messages arising from this discussion paper are at Attachment A.

**Energy Networks Association**

The Energy Networks Association (ENA) is the peak national body for Australia's energy networks which provide the vital link between gas and electricity producers and consumers. ENA represents gas distribution and electricity network businesses on economic, technical and safety regulation and national energy policy issues.

Energy network businesses deliver electricity and gas to over 13 million customer connections across Australia through approximately 800,000 kilometres of electricity distribution lines. There are also 76,000 kilometres of gas distribution pipelines. These distribution networks are valued at more than $40 billion and each year energy network businesses undertake investment of more than $5 billion in distribution network operation, reinforcement, expansions and greenfields extensions. Electricity transmission network owners operate over 42,000 km of high voltage transmission lines, with a value of $10 billion and undertake $1.2 billion in investment each year.

ENA distribution-sector member businesses include:

- ActewAGL
- Jemena
- Aurora Energy
- CitiPower
- Country Energy
- ENERGEX
- EnergyAustralia
- Envestra
- Ergon Energy
- ETSA Utilities
- Horizon Power
- Integral Energy
- Multinet Gas
- NT Power and Water Corporation
- Powercor
- SP AusNet
- United Energy Distribution
- Western Power

This policy framework discussion paper was developed by the members of ENA, and represents a distribution-sector wide policy position.

# Chapter 1 Introduction

## *1.1 Why this is a critical issue?*

Public policy developments applying to the energy supply sector are set to increase incentives for the connection of embedded generation (EG). In particular, the potential implementation of an Australian Carbon Pollution Reduction Scheme (CPRS), the proposed expansion of the Renewable Energy Target (RET), the pending national smart meter rollout and ongoing pressure for regulatory reforms seeking more detailed information provision and planning requirements on network opportunities. This will further increase opportunities for connection of EG and pose challenges for distribution networks.

ENA expects these trends to increase the need for a consistent and effective national approach to the legislative and regulatory framework covering the pricing, contracting, security and reliability and processing of all classes of EG. In particular, the potential for major increases in the amount of renewable energy generation into the National Electricity Market (NEM) over the next decade will bring about significant changes in the mix of generation technology connected to transmission and distribution networks. Among the challenges this will bring to the network are the need to accommodate a substantial increase in renewable energy generation (much of which could be intermittent) and the provision of market information that facilitates the timely entry of EG into areas where the most efficient contribution to the network can be made.

In preparing to deal with the new trends in EG the ENA Demand Management and Embedded Generation Committee has prioritised the development of this Discussion Paper to inform policy makers and stakeholders of the issues for consideration in developing a nationally consistent regulatory framework for the connection, pricing, contracting and operation of EG. In particular, it is hoped that this paper will inform the pending Australian Energy Markets Commission (AEMC) review of the energy market framework in the context of the introduction of the enhanced RET and the CPRS. The review was requested by the Ministerial Council for Energy (MCE) at its meeting of 13th July 2008.

Key definitions to technical terms used in this paper are at <u>Attachment C`</u>

## *1.2 Key issues from a network perspective*

The energy generated by EG can have an impact on the wholesale/retail market either due to the size of actual units or by the impact of many aggregated units. However, this issue is <u>not</u> the subject of this paper.

This paper focuses on the impact of EG from a network perspective. Critical issues include:

- Pricing – Transmission use of system (TUoS) and Distribution use of system (DUoS) prices that reflect network costs.

- Technical Requirements – Safety of personnel and the public is paramount, protection of the EG itself, security and stability of the power system to which the EG is connected, quality of supply, metering requirements.

- Contractual Issues – Factors that need to be considered in the contractual arrangement between an EG proponent/owner/operator and a Distribution Network Service Provider (DNSP). Alternatively the contractual considerations when a DNSP seeks EG to provide network support.

## 1.3 Update on Australian Government policy developments with respect to EG.

***The Mandatory Renewable Energy Target***

The Australian Government's mandatory renewable energy requirement is enhanced in all states and territories through a 10 to 20 per cent renewable energy target, with the exception of Tasmania, Northern Territory and South Australia

Introduced in 2001, the national Mandatory Renewable Energy Target (MRET) scheme, enacted in the Renewable Energy Act 2000, sought to increase renewable electricity generation. The scheme uses a system of tradeable certificates and requires the generation of 9 500 gigawatt hours of additional electricity by 2010 over and above existing renewable generation, and maintains this target until 2020. More recently, the new Australian Labor Government has indicated that it plans to expand this target to 45 000 gigawatt hours in 2020.

***Support for Renewable Energy in Remote Areas***

In August 2006 the then Prime Minister announced a further $126 million on top of the $205 million already committed over four years for the Renewable Remote Power Generation Programme which provides rebates for installed renewable energy technologies in remote areas.

***Support for Solar Energy for Residential and Communal Buildings***

In May 2007 the Australian Government announced additional funding of $150 million, up from $51. 8 million, for the Photo Voltaic Rebate Program, which provides cash rebates for householders and community groups who install photo voltaic systems. This initiative increases the rebate from $4 per watt to $8 per watt up to a maximum of $8000 for each residence. The initiative is funded for 5 years and will run to 2012. In the May 2008 Budget the Australian Government announced that access to the rebate would be restricted to house holds with an annual taxable income of less that $100 000 per year.

At the State/Territory level there has been increased support for enhanced solar feed-in tariffs. These arrangements have been legislated in South Australia, Victoria and Queensland where they apply to generators net output of renewable energy. The ACT is has upgraded its arrangements.

***Ministerial Council on Energy policy and regulatory work***

The February 2006 Council of Australian Governments (COAG) Communiqué outlined a commitment to implement a comprehensive and enhanced MCE work plan, from 2006, to establish effective demand-side response mechanisms in the electricity market, including network owner incentives, effectively valuing demand-side responses, regulation and pricing of EG, and end user education. [1]

The MCE Energy Market Reform Working Group (EMRWG) is currently looking at demand management and embedded generation issues relevant to the new *National Electricity Rules* applying to distribution businesses. This Working Group is chaired by the Commonwealth.

***Draft National Code of Practice for Embedded Generation and Impediments to renewable and embedded generation***

Regulatory approaches to the connection and operation of embedded generation have been part of a number of past MCE consultation processes. The ENA provided a detailed submission in response to the 2006 release of the Draft National Code of Practice for Embedded Generation and associated Consultation Paper on the Code of Practice and Discussion Paper on Impediments to the Uptake of Renewable and Distributed Energy.

No further public action was taken on this consultation process until the release of the NERA/Allen consultation paper on 23 August 2007 (discussed in more detail below) which purported to take into consideration the recommendations, submissions and issues through this earlier consultation process. An October 2006 CRA International report commissioned following the consultation on the draft Code of Practice and Discussion paper was released as part of the 23 August 2007 package.

***Economic regulatory incentives for demand side response and embedded generation***

As part of the MCE response to the COAG decision to increase incentives for demand side response (DSR) and EG, the MCE SCO released as part of the economic regulatory package released on 13 April 2007 three papers prepared by NERA Consulting.

The intention of the papers was to assess the draft economic regulatory package and make recommendations on approaches that would deliver a balanced regulatory framework between network and non-network options, including EG. The consultant did not consider (or recommend) possible approaches that would provide incentives for DSR or EG. ENA understands that possible incentives could be the subject of further MCE work.

The NERA papers included 28 recommendations, some of which sought immediate changes to the current draft rules, while the majority recommended further work be undertaken to develop appropriate approaches. The papers focus on efficient pricing through interval meters to incentivise DSR and EG, but recommended introduction (or continuation) of some specific mechanisms until efficient pricing is achieved.

[1] Council of Australian Governments, *Meeting Communiqué*, 10 February 2006.

In particular, the NERA papers recommended the following approaches or mechanisms to support embedded generation:

- The Rules should require that, once the appropriate form of regulation is determined for domestic distribution use of system charges, distribution network service providers (DNSPs) should be required to allow such customers to install and use PV on the basis of the same usage and capacity tariff elements applying to equivalent sized load.

- The initial Rules should not permit DNSPs to levy on EGs either positive DUoS charges for energy exported to the grid or deep connection costs.

  Voluntary payments from EGs to DNSPs should be permitted where a EG agrees to pay for upstream augmentations in order to increase energy transfer capability, in the same way that a transmission connected generator can pay for upstream augmentations of the transmission system.

- The initial Rules should retain a requirement for DNSPs to submit their proposed negotiating framework for EG connection charges to the regulator for approval and subsequent publication. The Rules should require the Australian Energy Regulatory (AER) to be satisfied that this framework:

  1. provides for a robust procedure for the negotiation of connection agreements, including information exchange;

  2. requires EGs only to fund shallow connection costs, where shallow is defined as the nearest point of the existing shared distribution network; and

  3. provides for EG proponents to be made aware of the options for the funding of deep connection costs or the connection constraint consequences of these not being funded (either by the EG or customers), including measures to ensure the provision of sufficient information to apply the Regulatory Test so as to determine the extent of any appropriate user-funded network augmentation.

- The Rules should remove the requirement for DNSPs to make avoided TUoS payments to EG owners.

  The Rules should continue to provide for both TNSPs and DNSPs to make network support payments to EGs or DSR providers, where the planning and Regulatory Test obligations under the Rules establish that such non-network solutions represent the most efficient means of alleviating a network constraint.

ENA's submission responding to the NERA papers considered that they represented a start to the consideration of this policy issue at a national level. The ENA submission, at a high level, supported the COAG and the MCE policy intention to remove unnecessary disincentives for EG. ENA also supported some recommendations such as removing current barriers to efficient pricing while opposing others. For example, that approved non-tariff-based demand management implementation costs should not be continued under a national regime. The submission noted, however, that most of the issues and recommendations in the NERA papers require further policy consideration by the Australian Energy Market Commission (AEMC) which was seen as the most appropriate body to develop future Rule changes to support EG and DSR.

***Approach to network planning, connections and losses***

The MCE SCO released a further set of studies on 23 August 2007 by NERA and Allen that recommend a new national approach to network planning, connections and losses. Recommendations adopted from this process will be incorporated into the second tranche "non-economic" regulatory package, expected to be completed in 2009.

The main NERA/Allen Consulting paper recommends the introduction of detailed information disclosure and planning requirements, a new approach to connections, as well as consideration of the case to introduce an incentive regime to ensure network losses are efficient. Significant variations exist as to recommended approaches between the NERA/Allen proposed approach, and the recommendations of reviews that have gone before it (such as the Code of Practice for embedded generation), particularly with regard to levying shallow and deep connection costs, and the scope for EG to offer viable alternatives to network augmentation. ENA forwarded a response to this paper to MCE SCO (http://www.ena.asn.au/udocs/ena_101107_143259.pdf)

In its submission ENA raised concerns that the NERA papers approach to distribution infrastructure planning and investment was simplistic and dominated by prescriptive and costly obligations that were disproportionate to the expected benefits of regulation.

# Chapter 2 The Current Regulatory Framework

An EG is defined in the National Electricity Rules (NER) as being a generator connected to a distribution network which does not have direct access to a transmission network. The NER makes a number of references to requirements for the connection and operation of the EG and also to compensation and charging principles applicable to EG.

Chapter 5 of the NER includes detailed obligations on network service providers for providing connection services, pass through of transmission use system (TUoS) costs and network planning. The Rules prescribe how various types and sizes of generator will be treated in terms of their participation in the National Electricity Market (NEM). The classification of generators includes:

<u>Registered or non registered generation</u>

All generators connecting to the distribution or transmission network must be registered with NEMMCO, unless they are subject to a general or specific NEMMCO exemption. A general exemption applies to generation units with a nameplate rating of less than 5MW, and specific exemptions are considered for generators up to a name plate rating of 30MW. Generators that have no capability to synchronise with the network are also exempt. Exemption means that persons who own such facilities are not required to pay participant fees and do not have their generation capacity scheduled or settled in the market.

<u>Scheduled or non-scheduled generation</u>

A generator with a rating in excess of 30 MW is classified as a scheduled generator, that is, one required to submit offers to the NEM wholesale dispatch process, unless classified otherwise by NEMMCO. Generators with a rating of less that 30 MW can operate as non-scheduled generators, that is, generators that do not participate in the NEM wholesale market.

<u>Market or non market generation.</u>

A generator is considered a non market generator if its output is purchased by either the local retailer or by a customer at the same connection point as the generator. Market generators operate in the NEM wholesale market.

***Network connection, including EG (section 5.5)***

The *National Electricity Rules* (NER) set out a process for the connection of all generators (registered and exempt) to the network. This process includes:

- A connection enquiry and resultant application;
- Satisfaction of technical and information requirements;
- Consultation with other network service providers, including transmission businesses, where the connection is over a particular size;

- An offer to connect;
- A connection agreement; and
- Eventual testing and energisation of the site.

These steps are subject to time limitations binding the network service provider, where the generation proponent provides all reasonable information required to connect to the site.

Specific access arrangement requirements applying to distribution businesses include:

- Provision to the connection applicant of such information as is reasonably requested to allow the connection applicant to fully assess the commercial significance of the distribution network user access arrangements to the distribution businesses (cl. 5.5(c)(2));
- Use of reasonable endeavours to provide the distribution network user access arrangements being sought by the connection applicant (cl. 5.5(e));
- Negotiation in good faith to reach agreement on connection service charges, use of systems charges and any compensation payable in the event the generation unit is constrained (cl. 5.5(f)); and
- Pass through of the locational component of prescribed transmission use of system charges that would have been payable by the distribution businesses had the embedded generator not been connected (cl. 5.5(h)).

***Planning and development of the network (section 5.6)***

There are a number of obligations on network service providers to consider non-network options when augmenting the network. These obligations interact with jurisdictional rules as outlined below.

Where the outcome of an annual planning review suggests that forecast load will exceed any relevant technical limits, distribution businesses are required to consult with affected registered participants, NEMMCO and interested parties on possible options to address the forecast shortfall. This consultation must include, but is not limited to, consideration of demand side options, generation options, and market network service options that may address the forecast shortfall. The distributor must also carry out an economic cost effectiveness analysis of all possible options that satisfy the Regulatory Test.

This consultation is not required if the network option to address the forecast shortfall would be a new small distribution network asset. A new small distribution network asset is defined under the Rules as an asset with an estimated total capitalised expenditure of $1 million to $10 million. The relevant jurisdictional regulator can specify another higher amount or other criteria to define a new small distribution network asset.

After a dispute period has passed without change, the distributor must arrange for the network options included in the report to be available for service by an agreed time.

***Regulatory Test (section 5.6.5A)***

The Regulatory Test is an economic cost-benefit test used by transmission and distribution businesses in the NEM to assess the efficiency of potential network investment. The test is developed by the AER (formerly the ACCC), in line with requirements set out in the NER.

In November 2007 the AER revised Regulatory Test for electricity network businesses along with explanatory and dispute resolution guidelines. The AER's revisions simplify and clarify aspects of the Regulatory Test and align the Regulatory Test to the NER while maintaining the reliability limb and the market benefits limb. The AER stated that it would provide input into the AEMC's work to integrate the two limbs of the Regulatory Test as part of the implementation of national transmission planning arrangements. Consequently the AEMC released a draft National Transmission Planning Arrangements report (2 May 2008) proposing a new Regulatory Test applying fit for transmission purposes. A final AEMC submission on this matter was submitted to the MCE for consideration in June 2008. The current Regulatory Test is to remain for distribution but is subject to the present MCE review of distribution and retail regulation.

The current Regulatory Test has two limbs:

- Reliability limb

  The reliability limb allows network investment necessitated solely by the need to meet minimum network performance requirements set out in the *Rules*, relevant legislation, regulation or statutory instrument of a jurisdiction, if the network investment option minimises the present value of costs, compared with alternative options.

- Market benefit limb

  The market benefit limb allows network investment which optimises the expected net present value of the market benefit, compared with alternative options.

A proponent is currently required to use either one or other of the two limbs of the Regulatory Test. However, the Energy Reform Implementation Group (ERIG) recommended combining the two limbs of the Regulatory Test. COAG has accepted this recommendation and is expected to refer the matter to the AEMC for implementation.

Proposed network investment is divided into new large network assets (>$10m) and new small network assets (>$1m). New small network asset proposals are not required to undertake a public consultation process; however investment still must meet the Regulatory Test. The majority of network augmentations occur under the reliability limb of the Regulatory Test.

For the purposes of the reliability limb of the Regulatory Test, an alternative option is an option that has a clearly identifiable proponent and is technically feasible. For the market benefits limb, an alternative option must deliver similar outcomes to the network proposal being assessed and become operational in a similar timeframe. The alternative proposal does not necessarily need an identified proponent in order to be considered.

Market benefits are calculated by considering the total benefits of an option to all those who produce, distribute, and consume electricity in the NEM, but not the transfer of surplus between consumers and producers. The market benefits limb can also include consideration of competition benefits, which include benefits arising from an increase in competition between generators across the NEM resulting from freer flowing transmission lines.

It should be noted that jurisdiction and transition arrangements under Chapter 9 of the NER have implication for the practical application of the Regulatory Test. For example, in Victoria the appropriate regulator is the Essential Services Commission Victoria (ESC) until a transfer of regulatory responsibility to the AER under a law of Victoria. The ESC has not mandated the Victorian Distribution Network Service Provider to carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the Regulatory Test. The derogation expires on 31 December 2010 or a later date fixed in a Victorian distribution pricing determination as the date on which the determination will cease to have effect.

***Prohibition of DUoS charges for export of Energy (Section 6.1.4)***

A Distribution Network Service Provider (DNSP) must not charge a Distribution Network User distribution use of system (DUoS) charges for the export of electricity generated by the user into the distribution network. This does not preclude charges for the connection services.

***Pricing Approach (Section 6.20)***

The NER provides for a "shallow" pricing approach where the EG owner pays for connection to the existing network. That is, the negotiated system service charges are based on the long run marginal cost for providing a distribution service at a connection point in a distribution network.

***Jurisdictional Arrangements***

The jurisdictions apply different approaches in their regulatory arrangements covering EG. Victoria and South Australia have developed specific access codes and guidelines applying to EG. In NSW EG provisions are incorporated in the overall concept of demand management. For Western Australia, the primary driver for demand management and EG (as with other jurisdictions) comes from the requirement to minimise the cost of providing network services by having to consider "alternative options". Queensland applies the NER's provisions whereby an EG is required to pay for its connection assets (shallow connection) and any augmentation to the upstream network (deep connection) and is only charged for the use of connection assets on an ongoing basis. There are no specific provisions covering EG in the ACT/NT where economic regulation soon comes under the national regulatory framework.

Half the states and territories, namely New South Wales, South Australia, Victoria and Western Australia, apply measures to assist and encourage the entry of EG, which are in addition to those applying in the access codes mentioned above. Initiatives include direct assistance for pilot projects in New South Wales and South Australia, discounted tariffs and concessions on capital contributions in Western Australia, mandatory connection requirements in Victoria, and guidelines, rules and information packages in some jurisdictions.

All states and territories, with the exception of Tasmania, New South Wales and the Northern Territory, have implemented provisions ensuring EG owners are paid for power provided to the grid. In the Northern Territory, PowerWater Corporation does offer to buy power from EG owners under a PV network agreement.

For a more detailed discussion of the respective State/Territory treatment of EG see Attachment B.

# Chapter 3 Issues with the Current Regulatory Framework

In March 2006[2] the ENA set out its position on certain aspects of EG as follows:

- Concern that costs on the network are not fully recognised;
- All generators should be required to pay the direct costs of connection as well as their contribution to network costs[3];
- Economic regulatory arrangements are critical in allowing fair sharing of benefits between the network business and embedded generators.

Among the issues that need to be carefully considered for a future national regulatory framework relating to EG are:

**Uniformity**

A primary issue, as regulation moves towards a national regime, is the level of uniformity in the definitions, requirements and conditions for EG.

This issue seems clear in the thinking of both the Standing Committee of Officials (SCO) of the Ministerial Council on Energy (MCE) and the DNSP's.

Consideration of the extent and content of some of the present "standard" codes, conditions and proposals for connection and operation reinforces the complexity of covering all likely situations. This paper seeks to highlight what seem to be the most important issues although it recognises that many may remain for further consideration.

**How capital contributions and fees for connection should be determined?**

Currently EG owners' connection costs only reflect the costs of connecting them directly to the network ("shallow" costing) plus some negotiated additional costs relating to shared network augmentation. They are not generally exposed to the cost of increased congestion resulting from EG investment decisions ("deep" costing).

There is also the matter of whether and how to apply avoided use of system charges which under the current Rules are treated as cost savings to be passed on to the EG even though there may be no relationship to actual cost savings.

Another matter is how to deal with capital cost cover where the initial generator connected to a dedicated network is followed by subsequent EG requiring access to the same network.

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[2] ENA Submission to the Ministerial Council on Energy, Standing Committee of Officials, on the MCE papers 'Impediments to the Uptake of Renewable and Distributed Generation – Discussion Paper' and 'Draft National Code of Practice for Embedded Generation', 31 March 2006, page 1.

[3] The DMEGC noted at its 27 March 2008 meeting 'a discussion whether an embedded generator would cover all costs' noting this as a matter 'which could be further explored in the discussion paper'.

There is also the issue of not penalising DNSPs relating to the increased risks of not meeting reliability requirements under service performance incentive target arrangements due to the lack of firmness attached to electricity supplied by renewable energy sources.

**Technical issues that have to be addressed**

Technical issues commonly differ depending on the size and type of EG. Such issues include metering requirements, protection, fault levels, voltage generation, power quality and connection and quality protocols. The basis for dealing with these matters depend foremost on resolving how best to differentiate the classes of EG. These are discussed further in Chapter 4.

**Establishing clarity in EG contracts and operating processes?**

The potential for regulation to provide for establishment of processes for conveying opportunities for EG development and the intention of EG investors as well as for the application and acceptance of EG need to be assessed. There is also a need to ensure that the relationship between network providers and EG owners provides for clarity as to the process for application and acceptance of obligations, liabilities, and sanctions.

Contract clarity also needs to be established with respect to the provision of network services to the EG owner taking account of the classification of the EG, the reliability of supply and the magnitude of network support required, if applicable.

**Reliability Obligation under the NER**

There is also the issue of not unduly penalising DNSPs relating to the increased risks of not meeting reliability requirements under service performance incentive target arrangements arising from lower reliability outcomes relating to electricity supplied by intermittent renewable energy sources.

# Chapter 4 EG Classifications

## 4.1 Classes of EG and their definition in regulations

EG can contribute to the supply/demand balance, supply back-up energy for sensitive loads such as hospitals, provide other important services to an end user such as steam through cogeneration and, by virtue of many of the technologies used, provide greenhouse benefits. In some limited cases, EG can also be used to manage local network congestion. A single installation can deliver some or all of these benefits to a number of parties

In terms of salient characteristics for classification, EG varies in quantity and quality of power they provide. Power supply reliability depends on the source of energy with those dependent on wind or sunlight being the least reliable. EG units also vary in size (electricity rating) from very small rooftop photo voltaic (PV) systems, to large gas cogeneration or wind energy developments. EG can be installed by any stakeholder in the electricity supply chain to augment peak supply, or by another party to sell energy to a retailer or customer, and if over 30MW, capacity can also be bid into the National Electricity Market (NEM).

The size of an EG unit will to a large extent determine the impact the EG will have on the operation of the distribution network. The connection process should reflect this difference such that small EG connections being simpler stand to gain most from a standardised approaches to connection, defined application and acceptance processing, charging and technical requirements.

## 4.2 Definitions of classes of EG

ENA notes that the Utility Regulators Forum (URF), as part of its "Draft National Code of Practice for EG" (February 2006) (http://www.mce.gov.au/assets/documents/mceinternet/DraftCoPEGforWeb20060221154032.pdf), proposed a tiered system for classifying EG installations. ENA accepts the need for a classification system to assist the consideration of EG issues and has based the following classification table on the URF proposal and the definitions used in AS 4777.

| Classification Band | Technical Definition (*) | Typical Installations (**) |
|---|---|---|
| Micro | Less than 2kW; AS4777 compliant; installed within a (domestic) customer installation and connected to the low voltage (LV) network via the customer service connection) | Inverter connected plant; Domestic roof top PV, micro wind turbines |
| Mini | Having a nameplate greater than 2kW and up to 10kW single phase or 30kW three phase; connected to the LV distribution and generally installed within a customer installation; not necessarily AS4777 compliant | Fuel cells; combined heat and power systems (CHP); mini hydro; mini wind turbines |
| Small | Having a name plate rating greater than 10kW single phase or 30kW three phase but no more than 1 MW and connected to the low voltage(LV)network; not AS4770 compliant | Induction machines - <br> biomass, landfill, small hydro, individual wind turbines, gas & diesel fuelled engine, small hydro; fuel cells; dc storage/inverter feeds |
| Medium | Having a name plate rating greater than 1MW but no more than 5 MW and connected to the high voltage(HV)network | Single or grouped large induction or smaller synchronous machines – biomass, landfill, hydro, wind, solar thermal, gas &diesel fuelled engine drives; <br> Large scale storage plus inverter feeds |
| Large | Having a name plate rating greater than 5MW | Single or grouped synchronous or power electronic controlled induction machines - wind farms, hydro, solar thermal, gas & diesel fuelled plant |

(*) - Technical definitions of the classes modified by ENA to add a “mini” class to cover domestic type installations between from 2kW up to 10kW single phase and 30kW three phase rating.

(**) – Technical installation description added by ENA.

The scope of AS 4777 – Parts 1, 2 &3 – indicate it covers the electrical installation, inverter and grid protection requirements for invertor energy systems up to 10kVA single phase or up to 30kVA three phase which inject power through a (domestic) installation to the electricity network. This in turn will include all "micro" class of generation installations and may, but not necessarily, include installations in the "mini" class.

Notes in AS 4777 also indicate that the covered micro installations shall be approved by the appropriate electrical distributor and that, whilst it refers to the specified installations:

- similar principles could be used for larger installations
- it may be used for systems where the energy is from a variable alternating current source (for example; wind turbines or mini hydro) with appropriate changes to the tests.

By way of comparison ESC of South Australia use kVA units rather than kW units (which allows for reactive power characteristics as indicated power factor being the difference) and divides EG into two categories:

- Small: An inverter connected generator, 10kVA or less for as single phase and not greater than 30kVA for a three phase connection. That is, a generation connection which complies with AS4777
- Large: An EG which does not comply with AS4777

In making its case for a four tier classification URF states that a two tier classification does not adequately differentiate generators requiring rigorous technical consideration from those that do not. The 5MW output delineation between large EG and others in the URF proposal reflects the threshold in the NER which states that those generators rated above 5MW must comply with the technical arrangements for connection in accordance with Section5 of the Rules.

The small and medium classes cover a large range of generator capacity, plant types and likely network connection arrangements which may also require study to confirm a satisfactory installation and connection proposal.

For the remainder of this paper, ENA has adopted the amended URF classification bands, which removes the overlap between the micro and small classes through the increase to 5 tiers by the addition of a "mini" band.

# Chapter 5 Pricing

## 5.1 *Capital Charges & fees for connection*

For micro generators (for example; Photovoltaic domestic applications) ENA believes that under normal circumstances no additional capital or connection charges should apply beyond the cost of necessary additional metering. Therefore the following discussion will exclude micro EGs and in large part, mini EG**.**

### 5.1.1 Review of recommendations to date

***Fees for connection***

EGs are generally required to pay for their direct connection (shallow) plus some additional (Negotiated) shared network augmentation. EG connection costs can include transformers, circuit breakers and metering equipment dedicated to connecting a particular generator, and in some cases extending the distribution network beyond its previous reach. Connection costs can also include protection and control and the extension of remote communications control facilities to the EG. The costs of dedicated connection assets can be prohibitive for many generation projects, in particular remote wind energy projects, as they are often in rural areas and at the end of distribution lines which are not designed to handle two way energy flows.

The PB Associates report (February 2006) advocates that distributors be able to recover all reasonable costs associated with connection of the EG. This extends to costs associated with connection, extension and augmentation (including upstream reinforcement charges, that is, "deep" costs). Small and micro EG unit charges are limited to a levy associated with dedicated connection assets.

CRA (October 2006) suggests the EG units be recognised for the market dispatch benefits they bring to the network and that this be considered in the assessment of fees.

The NERA/Allen paper (October 2007) recommends that all generation and load connected to the distribution network be charged the marginal costs of providing the dedicated assets associated with that connection ("shallow" costs). This recommendation is at odds with previous reviews which have recommended that the costs of "standard" connections of small customers be included in the shared costs of the network and not charged to the individual customer.[4]

In some jurisdictions the customer funds the dedicated assets but the connection service is contestable. Across a number of other jurisdictions, connections are charged on the basis of the net incremental connection costs minus the incremental revenue expected from the connection.

There are pros and cons under these approaches and the divergence between them means quite significant changes for some jurisdictions if a nationally consistent approach is preferred.

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[4] This discrepancy in approach is noted in the NERA/Allen paper, pp. 84-88.

***Augmentations to shared assets***

The NERA/Allen paper recommends that any augmentations to shared network arising from the connection of a load or generation be recovered through shared network charges. This approach is contrary to that set out in past reviews of this issue by Gilbert+Tobin, AAR, PB and CRA.

The rationale for the NERA/Allen approach is that augmentations to the upstream network required to deliver transfer capacity for the EG should be paid for voluntarily by the generator, or the generator's output should be constrained to a level that ensures system security. This approach works for transmission as most transmission connected generators are dispatched by National Electricity Market Management Company (NEMMCO), in line with detailed constraint algorithms that ensure system security.

The NERA/Allen paper attempts to replicate these arrangements for the distribution network. It does this by placing an obligation on distribution businesses to ensure system security by allowing the distribution businesses to impose constraints through connection contracts. The intent is to effectively replicate through contracts the role currently played by NEMMCO through a centrally controlled dispatch engine.

### 5.1.2 ENA position on the development of a nationally consistent approach taking into account Classes of EG

The default service that Distribution Businesses provide to connected parties is not constrained under normal operating conditions, that is, all items of network plant are assumed to be in service. However, where access is not under normal operating conditions there should be no obligation by DNSPs to provide an unconstrained connection.

EGs should be entitled to negotiate different terms than the normal DNSP default level and thereby avoid obligation to fund deep (upstream) distribution augmentations. Additional control equipment would normally be required to be installed to manage the generator output during times of constraint. The generator would be obliged to fund any such control equipment and the operating regime enforced by this control equipment would be defined in the connection agreement between the generator and the DNSP.

ENA's view is that capital contributions and fees for connections should be formulated to address the particular characteristics of each class of generator. While seeking capital contributions for marginal network equipment by the EG seems clearly relevant for at least the shallow connection assets, the possible need for further upstream system alteration needs consideration, at least for some classes of EG.

To the extent possible, charges for connection of EGs should follow the same principles and rules as those that apply to the connection of similar sized loads.

As a general principle ENA's view is that if a generator does not pay the full costs of connection to the network then there should be a mechanism to ensure that the generator connection is not subsidised by those not directly benefiting from the generator connection. This outcome can be achieved by ensuring that the regulatory regime is cost reflective of all costs incurred in connecting the generator. Alternatively, the generator cannot be guaranteed unconstrained access to the network.

The relative size of the generation compared with system capacity at the proposed connection point will bear on the augmentation required as would the proposed mode of operation of the EG. For example, a generator used to "peak lop" load on a site might be treated differently from one used for "base load" but which required network input at peak times. Generation specifically for network support (without directly associated site load) might be different again, and might vary according to firmness of its availability and the network's ability to schedule its operation.

**Key Messages**

Regulators need to ensure that an EG's connection is not subsidised by those not directly benefiting from the EG connection.

Access cannot be guaranteed to be firm (that is; access guaranteed to be unconstrained 100 percent of the time).

The regime should be "cost reflective" of all costs.

## 5.2 System Charges

### 5.2.1 Review of past recommendations

***DUoS based charge for EG units?***

Under the NER the EG proponent is obliged to pay either an upfront charge or alternatively a use of system tariff.

Charges could be associated with contracted arrangements for a normally self-supporting site to call on network access, for example, by arrangement for machine maintenance with short time notice or for full or limited network supply to be available immediately without notice.

However, "Clause 6.1.4 of the NER precludes the application of DUoS charges for the energy they export into the network. While applicable specifically to "Network Users", it does set up some degree of conflict to propose charging EGs such charges. An EG proponent may interpret the NER to be that if they sit behind a load connection point they achieve "Network User" status and avoid network charges. As there is a need for consistency between pure generators and combined generator/load arrangements consideration should be given to a change to Rule Clause 6.1.4.

Where network users embed generators to reduce their network load, requests for preserving capacity in the network (standby) should be subject to a charging regime. These otherwise unused assets should not be reserved unless originally the subject of a capital contribution. Automatically ratcheting and resetting annual capacity charges are an example of a possible means of applying such charges.

An alternative may be to apply a once off fee which would reflect all network related costs in accommodating a new EG unit including stand by capacity for delivery of purchased energy.

### *Extension of assets issue*

PB Associates advocate that the distributor be obliged to publish policies and procedures dealing with EG connections where the asset involved was constructed for an earlier EG connectee who has made a payment for the connection assets. The distributor policy requires a reimbursement by the distributor to the original EG owner (for example, NSW IPART determination for reimbursement of subsequent sharing of load connection extensions)

The NERA/Allen paper recommends the development of a guideline to govern the approach for refunding an initial investor for extension assets that subsequently become shared. The Paper does not make specific recommendations as to what these arrangements should be, beyond a recommendation as to the timeframe over which a refund could be recovered.

The Garnaut Climate Change Review Report (September2008) recognised the "first mover" problem as a market failure giving rise to an incentive for potentially larger generators to delay investment in the hope that others step in first.

### *Feed in Tariffs (for micro/PV installations)*

The inference ENA draws from the references to feed-in tariffs in the Garnaut Climate Change Review Report is that it refers to micro EG, as it refers to "household electricity generation".

The report suggests there is a limited case for feed-in tariffs where they reflect the net value of externalities relating to electricity transmission and distribution networks. These benefits include reduction in line losses due to the locational advantages inherent in EG and benefits of deferred network augmentation.

ENA's view is that the these benefits will not always result from EG installations. Where they do, the value is very unlikely to be as high as current feed in tariff multipliers (multiples of three and four time the benchmark tariff).

The Draft report notes that feed in tariffs can be paid on the basis of gross metering (where the EG is paid for all its generated electricity) or net metering (where the EG is paid for electricity generated net of that consumed by the generator host installation). In Australia both approaches are used depending on the jurisdiction.

Garnaut recommends that feed in tariffs be based on gross metering because this option better reflects the benefits of EG, but this is conditional on the price reflecting the true value of the benefits. The report further notes *"If governments opt for a higher tariff, then the rest of the customer base will be cross-subsidising embedded generators. The reintroduction of a cross-subsidy would run counter to the reforms of the last decade."*

ENA notes that further work is going on through MCE to harmonise feed-in tariff arrangements.

#### 5.2.2 ENA position on the development of a nationally consistent approach taking into account Classes of EG

ENA gives in principle support to a nationally consistent approach to the treatment of DUoS charges with the outcome of any consideration by the AEMC reflecting the principle of cost reflective pricing. However, ENA notes a number of studies, for example Newington in Western Sydney, confirm that solar PV may not coincide with peak customer demand. Network capacity is a prime driver of investment and thus pricing.

**Key Messages:**

ENA recommends further consideration be given to the application of DUoS charges, first mover issues and feed in tariffs.

ENA notes that a number of studies have demonstrated that the installation of large scale PV may not benefit the performance of the electricity supply network.

There is a need for consistency between pure generators and combined generator/load arrangements. This requires consideration of a change to Rule Clause 6.1.4.

Where network users embed generators to reduce their network load, requests for preserving capacity in the network (standby) should be subject to an appropriate charging regime.

Alternatively, a once off fee should apply which would reflect all network related costs in accommodating a new EG unit including stand by capacity for delivery of purchased energy.

## *5.3* Payments from Networks to Embedded Generators

#### 5.3.1 Treatment of avoided costs

PB Associates position is that distributors should be obliged to quantify the benefits that may accrue to them from the connection of an EG unit. This obligation does not extend to micro EG units unless otherwise agreed between the parties.

The quantified benefits include:

- avoided TUoS,
- deferred benefits of avoided distribution augmentation, and
- payments which may be made to the EG owner in respect of the provision of network support services.

Avoided TUoS is specified to be the difference between the payment the DNSP would make to the TNSP without and with the EG installation. This can be calculated from the supply point metering data and paid periodically as agreed

If requested by the EG owner the distributor must pay an amount in respect of deferral of network investment – which is commonly presumed to be a benefit but is not necessarily relevant unless there is an identified existing or pending network constraint. The payment will be based on the annualised value of the deferred network augmentation capital and operating costs. It could also reflect the availability, reliability, and despatch ability of the generation.

Network support payment by a network service provider to a generator is covered more fully in Chapter 10. In general, the payment amount would depend on the support need defined by the DNSP, the agreed capability and duration of the EG service and the annualised value of the alternate network augmentation.

### 5.3.2 ENA Position on avoided TUoS/DUoS

ENA considers that avoided TUoS and DUoS arrangements are demonstrably inefficient and flawed in their application. Predetermined rebates for embedded generators risk cross subsidising one segment of the economy with no countervailing benefit and to the exclusion of other, more cost effective demand side options.

TUoS charges are mechanism pertaining to the TNSP to collect its allowed revenue, with a reduction in one area resulting in a compensating increase in rates across others. Hence, site specific TUoS changes resulting from a particular EG do not result in any saving per se, but rather a readjustment of the UoS charging regime.

EG, to a DNSP, is no different to an interruptible load, or a reduction in load. For this reason claims for network support payments by EGs should be managed through the same process for sourcing and evaluating DM options that is used for all other options (See Chapter 10). No generation specific rebate arrangements should exist if they fail to recognise actual avoided costs.

The following issues arise with respect to avoided TUoS requirements:

- TNSP price structures vary (as permitted under the Rules) and the usage charge is based on a cost allocation process then converted to a structure, which is not cost reflective. If this component of TUoS price is used to determine avoided TUoS payments, it results in an economically inefficient outcome.
- This is particularly the case with generators such as wind generators, which may not be able to provide transmission network support sufficient to defer any augmentation.
- TNSP revenue is regulated and any notional avoided TUoS charges which are not avoided as charges are simply reallocated and recovered in the following year via common service charges levied on all customers.
- The present arrangement is unstable. Where a connection point supplies load and EG of approximately the same size, the TUoS usage charge (which recovers a demand-related component of the transmission assets) would increase asymptotically. This is the case since during failure of the generator the full capacity of the network would be used and the full associated costs allocated, yet the net metered usage quantities at the transmission connection point diminish.

The above points also apply to avoided DUoS charges. The use of the term "avoided DUoS" is misleading. DUoS can only be avoided where an embedded generator is placed behind a meter within a customer installation that would otherwise pay DUoS charges. In that circumstance all the DUoS that can be is avoided by the host customer. This could also be considered an uneconomic subsidy as no actual costs are being avoided (for example if the embedded generator does not affect peak demands, or if no network investment is avoided).

The present procedures provide adequate scope for the negotiation of appropriate network support payments. Experience shows that a major concern regarding these payments is a qualified understanding by the EG proponent of the network role and performance requirements, the Rules obligations and the nature and capabilities of their proposed plant. Examples of this can be seen in the perception that all EG is good because it is close to the load and hence reduces losses, improves voltage regulation and reliability when in fact it can significantly worsen these aspects of network performance (depending on the match of capacity and output to the load profile, the type of plant and its control, and the number of machines).

**Key Message:**

The requirement for DNSPs to make avoided TUoS payments to embedded generators should be removed from the Rules.

ENA supports the use of network support payments to embedded generators, where the planning and Regulatory Test obligations under the Rules establish that such non-network solutions represent the most efficient means of alleviating a network constraint.

# Chapter 6 Technical Requirements

## 6.1 Technical Requirements

The issue of compliance with minimum technical requirements relating to the connection of loads or generators to an electricity network must be addressed to ensure that the overall integrity of the network is maintained, and any adverse impacts on public health and safety, and existing customers and network assets and any future connection are minimised.

The technical requirements for the connection of a generator onto a network are dependant upon the:

- type (induction machines, synchronous machines, power electronic sourced and controlled, thermal plant, hydro plant, wind plant, photovoltaic plant and various combinations)

- size of generating unit (from below 1kW: for example - PV installations; to above 100MW, for example, a gas turbine or wind farm installation).

- the electrical location within the network (domestic LV service connection; commercial/industrial LV/MV distribution network connection; sub-transmission network connection; strong urban network or light rural network service), and

- the configuration at the connection point (direct connection to distribution mains; interposing distribution substation; step up zone substation; single (radial or multiple element connection).

EG covers a wide range of installations. Even so, it is desirable to have uniformity of principles with respect to the technical requirements for connection across all generation types – as reflected in the notes to the scope of AS 4777.

Chapter 5 of the NER deals in detail with the requirements of generators to provide data to the network service provider. For generators or generating systems greater than 30MW there are specific code requirements relating to NEMMCO. For generators or generating schemes it is up to the network service provider's requirements, as per clause S5.5.6 of the NER. For generating schemes above 10MW the DNSP must notify the TNSP, as per clause 5.3.5 (e).

Given the range of possible EG installation, there is a need for the Standards schedules currently listed in Section 5 of the NER to be expanded to include pro formas which are drafted more specifically to suit the various types of installations.

Approval by NEMMCO is required for connection of generation 30MW and above (EG below 30 MW requires network service provider approval). This is similar to what has been developed for inverter connected units up to 10kVA for single phase and 30kVA for three phase in AS 4777.1 – 2005. There is a requirement to employ a common technical approach where possible to deal with each class of EG including interface and protection requirements.

**Key Message:**

It may be beneficial to develop standard technical requirements for each generation class connections below 30 MW.

## 6.2 Safety

Technical requirements and associated safety laws are not consistent across all distribution networks. Accordingly, ENA launched a policy in April 2008 supporting a common approach to energy safety in Australia, including the creation of a single national energy safety regulatory agency.

The ENA policy on *a National Framework for Energy Safety in Australia* sets out how a common approach to energy technical and safety regulation in Australia can be incorporated in Australian law and assist in the delivery of safe, reliable and affordable energy.

ENA released a *Proposed National Framework for Electricity Network Safety* in July 2008 as the recommended approach to national electricity network safety regulation.. The proposed framework sets out the scope for a safety case, which is a detailed document prepared by a network operator that:

- Identifies all the known and credible hazards and risks.
- Describes how the risks are to be managed.
- Describes the safety management system needed to ensure the controls are effectively and consistently applied and performance is measured and continuously improved

**Key Messages:**

Electricity networks are characterised by extensive distributed assets throughout the public domain such as powerlines, substations and underground cables.

There will be additional complexity and costs associated with the management of hazards and risks posed by the operation of embedded generation.

In having an industry wide approach, the safety requirements established for each of the DNSP's cannot be compromised for any of the different classes of EG.

## 6.3 Network Protection

The network protection requirements for the connection of EGs are necessary to ensure that the operation of the generating units do not:

1. Increase public health and safety risks;
2. Cause any reduction in power transfer capability of the network due to reduced rotor angle stability; reduced frequency stability; or reduced voltage stability;

3. Cause any increased need for load shedding in the event of an unplanned trip of the generating unit due to the rate of change of frequency; magnitude of frequency excursions; active power imbalance; reactive power imbalance; or displacement of reactive power capability; and

4. Adversely affect the DNSP or other users caused by transients relative to the level that would be applicable if the EG unit were not connected.

The degree of potential impact on the network is directly proportional with the size of generating capacity of the EG connecting to the network.

For example, a mini EG such as a 3 kW to 5 kW photovoltaic system is unlikely to reduce or limit the power transfer capability of a network or cause any increased need for load shedding in the event of an unplanned disconnection from the network under contingency conditions resulting from the operation of protection equipment. In the case of the latter, the generating capacity lost is well within the capability of the existing network and generating[5] capacity to absorb and will not result in the need for any load shedding. As such, the network is unlikely to detect any material voltage or frequency variations. The primary concern for the connection of micro EGs would be the increased risk to public health and safety due to the potential for islanded operation, although for inverter connected systems this risk is relatively low.

For small EGs and above connected to the distribution network, the risk of islanded operation following a network outage is relatively high. The public health and safety risks of islanded operation for EGs of this size is significant, hence protection against islanded operation is essential.

In the case of larger EGs in the order of 30MW and above, depending on the operating characteristics and connection point in the network, momentary network disturbances such as short-circuit faults which may occur in geographically remote but electrically proximate locations can result in voltage and synchronous instability of the power system causing widespread system failure. In such situations, network protection upgrades may be required at points within the network that is geographically remote but electrically proximate from the EG's point of connection to ensure that short-circuit faults are cleared within more onerous critical fault clearance times. Moreover, additional or more stringent local protection at the point of connection may be required to detect and mitigate the risks of transient voltage dips or frequency excursions.

### 6.3.1 Protection by Class

**Micro EGs**

The protection requirements for inverter connected micro EGs are outlined in AS4777.3-2005. Generally, proof that an inverter is compliant with AS4777.3-2005 by the provision of a test

[5] i.e. Spinning reserve.

certificate prepared by a NATA[6] certified test laboratory is sufficient for a DNSP to grant approval to connect in respect to protection requirements. The connection of multiple inverters in parallel may result in the requirement for additional levels of protection.

**Other Classes of EGs**

The protection requirements of other classes of EGs vary depending on the following factors:

1. Characteristics of the generator including size, intermittency, coefficient of inertia, and
2. Point of connection, that is, short-circuit strength at the connection point.

Power system studies are generally required for EGs in the medium and larger classes (that is, greater than 1 MW may be required for some installations towards the higher end of the small class, and, for example, greater than 200 KW connected to an LV or weak MV distribution network) to determine the potential need for more stringent or onerous protection requirements, such as fault clearance times. Notwithstanding the specific requirements, it is highly desirable to standardise or harmonise the protection requirements for the connection of EGs across all jurisdictions. Aspects to be taken into account include:

1. The requirement for duplicated protection (NEMMCO requirements);
2. Provision of inter-tripping back to the DNSP to prevent islanding operation with associated communications protocols;
3. Compliance with national and international standards including IEC60255-8; and
4. The data to be provided by EG proponents to the DNSP for assessing the network impact of connection can be made consistent.

### 6.3.2 ENA Position

Different detailed protection requirements are likely to be necessary for different classes of EG. Further work is necessary to determine protection requirements for different classes of EG to identify specific areas of standardisation or harmonisation, for example, metro versus rural connection points.

| **Key Message:** |
|---|
| Other than the micro EG class, the protection requirements for EGs can vary depending on the characteristics of the generating unit and the point of connection. However, harmonisation of protection requirements across jurisdictions and DNSPs is highly desirable to achieve efficiencies with respect to the ability for EG products and schemes to be connected in different parts within a network and in different networks; thereby minimising the costs of variations and modifications to proponents. |

[6] National Association of Testing Authorities.

### 6.3.3 Communication

The extent of communication networks for monitoring, protection and control is limited at the distribution interface. The growing number of different generation types, different operating characteristics and a wide range of generation capacities create the need for a complex communication infrastructure. The impact that EG has on the network both at a distribution and transmission level requires bi-directional data exchange and far greater quantities of data to be communicated.

The smart meter roll out involves some aspects of communication capability with the resulting multiple register, time interval based information accessible by telephone dial-up or other means able to assist the network operating and performance assessment needs.

### 6.3.4 Islanding

Islanding of a distributed generator is caused by a disturbance on the network which results from a protection operation which separates the EG connection from the general body of the network and leaves it to supply the local (island) load. This can result in safety risk and supply quality problems (refer Section 6.2) unless the EG is intended and designed to take over the load supply in the event of the loss of the mains power supply.

The methods used to ensure disconnection from the network to avoid islanding are usually based on the network connection point information only and therefore cannot be totally reliable. This means that unnecessary trips can occur or conversely the EG may be unable to detect situations where tripping is required. Given the present status and configuration of a distribution network all reasonable precautions must be taken to prevent the intentional or un-intentional islanding of embedded generator systems

## *6.4 Metering by Class*

### 6.4.1 Tariff Metering

Except for some fixed small loads (for example; public telephone boxes), all customer installations (loads, generators and combinations) must be metered. The metering information is required to allow the calculation of payments to be made to and by the generator and to assess the operating impacts of the EG on the network.

EG only installations can export energy to the network (generator output) and import energy from the network (generator load from auxiliary supplies, such as heating, braking, slewing and monitoring systems for wind farms).

The energy import/export requirements for a combined EG/load installation will depend on load requirements and generation output at any given time. Such variations in energy import/export requirements for a combined EG/load installation will influence the needed connection and metering arrangements.

Electronic interval meters[7] are required for all new installations. Each installation has to be in accordance with Chapter 7 of the NER. Data from these meters shall be made available to the network service provider.

Large, medium and high end small EG installations will be directly connected to the network and have independent metering installations. The metering data information to be supplied to the network service provider will require a:

- Register of the energy (kWh and KVarh) imported from the network to the customer,
- Register of the energy (KWh and KVarh) exported by the customer to the network.

Additonally, the metering may be required to register the real and reactive output power of the EG (kW/MW; kVA/MVA; kVAr/MVAr) where it is associated with providing network support capacity.

Micro, mini and low end small EG will generally be connected within a customer installation and hence associated with the supply of load. The EG metering will be part of the overall installation metering, which will generally require registers to record energy (kWhs) and demand (kWs) for either:

- the net import/export resulting from the generator/load combination or
- the separate (or gross) generator output/load usage components.

The needed metering configuration will depend on the relevant DNSP information, jurisdiction and tariff requirements, such as solar PV feed-in arrangements which presently vary between jurisdictions.

### 6.4.2 Line Current and Current/Voltage Transformer (CT/VT) Metering

For loads or generators connected to the LV network and drawing/supplying up to 80Amps of current per phase (20kVA single phase; 60kVA three phase) the metering is generally driven by passing the line current directly through the installation meter.

This arrangement is used generally for micro, mini and some small EG

The levels of current and voltage involved for the connection of larger capacity installations will generally require the use of current transformers (CTs) and voltage transformers to achieve workable metering installations. These reduce the magnitude of meter input currents (typical maximum 1 or 5 amps) and voltages (typical 110V) with connections via a secondary wiring system.

This arrangement is used for large, medium and high end small EG.

[7] In Qld type 5 meters must be registered as a type 6 metering installation and read as an accumulation meter.

The measurement of generation output and auxiliary energy use can be an issue with these installations due to the large difference in the quantities involved. For example, an EG export may be in the MW range whilst the auxiliary power import may be only kWs – giving a ratio of 1000/1. The meter sensitivity may not provide a meaningful measure of the auxiliary power use if used simply in an import/export mode. Hence, separate metering may be required for these components.

### 6.4.3 Net and Gross Metering Schemes – for EG within an installation

As indicated in 6.4.1 above, net or gross metering arrangements can be adopted for EG connected within a customer installation

Net metering will apply where the EG is intended to supply the customer load first (at any given time) with any net difference being either exported to the network (generation > load) or imported from the network (generation < load). A number of solar PV in-feed tariffs are formulated on this basis (for example; Queensland)

Gross metering occurs where the generator and load components are metered separately and are needed where EG payments may be based on the full output rather than net difference (for example the ACT feed in tariff).

Separate EG metering would also be required to derive the delivered capacity where the installation is intended to provide network support.

Gross metering could also be supported as a means of providing full information on the level and duration of EG contribution to a network load demand and delivered energy – both of which can affect planning requirements and network revenue information.

As a counter to this, full sample information sufficient to establish EG performance impacts (by class) could be sufficient to derive workable planning and revenue assessments without the total installation, communications and cost encumbrances full gross metering for all installations of claim[8]

An EG owner could prefer or require gross metering as means of maximising the benefits of an feed-in tariff for all energy produced especially if at a higher rate than grid charged electricity. Also this would provide the site with independent load and generation operational data.

In determining the most appropriate method the question that needs to be resolved is what metering scheme will provide the best outcome for the parties involved across each class of EG.

[8] Both net and gross metering schemes are used in the NEM. A summary of the types of these can be found Tables 6 & 7 in the document:
"Development of a Standard Connection Agreement for Small Grid Connected Renewable" – Discussion Paper January 2004, Robert Passey, David Roche, Muriel Watt, Ted Spooner

**Key Message**

ENA recognises that significant further consideration needs to be given to tariff (particularly mandated in-feed arrangements), jurisdiction and individual DNSP requirements which can influence the choice of net and gross metering arrangements for EG connected within a customer's installation.

## 6.5 Fault Level/ Voltage/Power Quality

For all EG all requirements relating to power quality are outlined by AS/NZ 61000.3.7:2001. Although there are guidelines set out in this AS/NZ, there can be network requirements that have specific constraints and hence it is the network service provider that determines the power quality requirements at each connection point. Large EG installations of aggregate exceeding 30MW must comply with any additional requirements as specified in the NER.

All connecting EGs have a responsibility to comply with the DNSP's requirements and as a minimum maintain the existing power quality conditions on the network as reflected in their contractual arrangements.

Fault levels are a technical aspect of a network determined by design and asset capability of both the network and the customers connected.

Connection of EG to the network can only be accommodated when the connection of the generator does not exceed the allowable fault level contribution as determined by the network service provider. Due to improving network utilisation and connecting generation electrically close to the distribution assets, the technical requirement to operate the network below fault level limits is becoming more difficult and hence more expensive to connect EG and maintain a safe working practice. This raises the question of financing the infrastructure augmentation to allow connection of additional generation. The current industry practice is that the connecting party that causes the fault limit to be exceeded pays the total cost to augment the infrastructure. In some situations these costs can result in financial barriers to proceed with connecting the generator. The introduction of some form of cost recovery mechanism could be considered to address this impending issue.

System voltage fluctuations and power surges affect customer reliability and supply quality. The level and type of generation will determine the degree of complexity. A significant component of EG in the southern areas of Australia will mainly come in the form of wind generation which has a variable and unpredictable generation source. The variability of this generation type makes forecasting generation complex and together with customer load variability means the balancing of the 'generation versus load' equation difficult. In the past this task has been carried out at a TNSP level heavily influenced by stable base load generation plants. The EG being introduced into the distribution network is another variable component entering into the equation. A clear mechanism and agreement on the planning and operational responsibilities need to be established.

As part of system security there are 'under frequency' and 'under voltage' customer load shedding schemes in operation. The European experience in 2003 showed that the standard load shed plan in place was able to maintain security of the network but the decentralised EG affect was not expected and finally provoked a system blackout. The EG being connected is a collection of large generation schemes 'riding through' system disturbance and medium, small and micro generation schemes disconnecting from the network. There is a requirement for more in depth understanding and co-ordination between the DNPS's, TNSP's and the generators to consider the impact of the increasing EG installations.

**Key Messages**

ENA's view is that the current protocol where the DNSP has the responsibility for fault level, voltage and power quality on the distribution network and its impact on related networks be maintained to preserve the integrity of the network.

ENA's firm position is that all costs incurred to ensure fault level, voltage and power quality be recognised and should be fully recovered under the regulatory arrangements.

# Chapter 7 Application and Connection Processes

## *7.1 Present Position*

The Application and Connection process applicable to a proposed EG connection will depend on the capacity (and hence class) of the proposed generator, the requirements applied by the involved DNSP and the procedures defined in Chapter 5 of the NER.

In general, the connection of an EG can be viewed as a two stage process being:

1. the "application" which involves the advice and assessment of a proposed project (including the completion of related network studies and the definition of needed performance requirements) which leads to an Offer to Connect and Connection Agreement between the EG proponent and the DNSP; and

2. the "physical connection" which involves the completion of the design and construction of the needed connection assets, the installation and commissioning of the EG plant including performance testing to determine compliance with the relevant/agreed performance standards.

The construction of the connection assets may involve work by both the DNSP and the proponent, this being undertaken by an accredited service provider (as contestable work) where that is applicable under the jurisdictional rules and may comprise shallow and deep connection works.

The Connection Agreement (CA) would contain the needed information relevant to the proposed installation and/or as required by the NER. The pro forma could be in two parts, the first being the general clauses, which define the terms and conditions of the CA and the second being the Schedules, which define the information specific to the EG project (for example; the Technical schedules listed in Chapter 5 of the NER).

## *7.2 ENA Position*

### 7.2.1 Connection process by class

ENA accepts that the connection process may vary with the class of the EG to be connected. Medium (1-5MW) and large (>5MW) EG would generally involve connection to the medium volt (MV) (11 or 22kV) and sub-transmission (33, 66,132kV) networks respectively and be subject to the NER procedures (refer to chapter 4).

Individual DNSP requirements would generally apply to Micro (<2kW), mini (<10/30KW) and small (<1MW) EG installations. These are generally connected to the low voltage (LV) network with those at the high end of the range possibly connected to the MV distribution network.

### 7.2.2 Uniform (Standard) Connection Processes

ENA supports the concept of DNSP's adopting uniform (or standardised) connection procedures. This would be achieved for the Medium and Large classes through the application of the NER procedures (enquiry, application, offer and agreement sequence) as the normal process.

Further consideration is required to define a suitable procedure for micro, mini and small EG connection proposals which would be acceptable to all DNSPs and take in to account the differing situations within the various jurisdictions.

Given that all micro plant is, and a large portion on mini plant will be AS 4777 compliant and connected within a domestic installation a suitable procedure for these could reflect that applied to the connection of new customer installations (refer to Section 6.3.1 of this paper) where:

- the work is undertaken by an accredited service provider (ASP) or licensed electrical contractor
- the intention to connect is notified to the DNSP in a similar way to a new installation
- the DNSP agrees to the connection subject to any local network, requirements (which could be different for urban and rural areas and may involve work by either the proponent or the DNSP).

| **Key Message** |
| --- |
| ENA intends to give consideration to the development of a standard procedure for the connection of micro, mini and relevant small EG |

#### 7.2.3 Automatic or Considered Connection?

ENA supports the adoption of a standard connection process for EG installation generally. This is consistent with its commitment to having a common procedure and uniform documentation for any EG connection proposal in the interest of simplifying the connection process and not as an indication of an automatic right to connect. This support should not be seen as an endorsement of the concept of providing the EG with an automatic right of connection.

ENA submits that the technical requirements outlined in Chapter 6 indicate that all but the micro and some small EG connections can impose the need to investigate the impacts of the proposed connection on the network performance and the capacity of the network to provide the required connection services.

In the longer term, the wide spread adoption of micro/mini EG (such as a PV array on every roof) could make it necessary to have a record of the number, capacity and location of every EG installation. Such records would allow the network operating, supplied power quality and safety performance affects of what could become substantial and increasing aggregated capacity to be assessed and monitored if/as needed.

Since the introduction of the Commonwealth Government's Photovoltaic Rebate Program (PVRP) and at the state government level feed-in tariffs and renewable energy buyback scheme (REBS), there has been marked increase in the uptake of micro/small EG systems[9]. This trend is likely to continue or accelerate going forward, given the impending introduction of the ETS and intense debate on climate change.

As such, careful consideration needs to be given to the definition of the capacity and characteristics of any plant to be given the right of automatic connection and the "record keeping" associated with their installation to minimise the impacts on network safety, reliability and security.

**Key Messages**

Standard connection processes, including common procedures and uniform documentation should be adopted where possible, having regard to the differences classes of EG.

ENA's view is that DNSPs need to be advised of all relevant detail relating to new EG installations (this includes; the location, capacity and type of each EG installation, the nominal capacity, the agreed generated performance standards, the required and agreed network services, the period of effect and any factors specific to the connection).

## *7.3 Limitations to Existing NER procedures*

The NER connection procedure outlines the sequence of submissions and responses required of the proponent and the DNSP, moving from an initial connection enquiry, to an application, an offer to connect by the DNSP and concluding with signed Connection Agreement based on the offer.

Whilst this process presents a logical sequence of connection activities, ENA submits that it has some inherent limitations in that:

- the prescribed response times are unrealistically short taking in to account those actually needed to complete many of the activities associated with a connection project;
- there is undue emphasis on the Application step as the key stage, and
- more recognition needs to be given to the need for consultation at the enquiry stage to identify issues associated with a proposed connection and allow the development of an "agreed project" which is reasonable and workable in terms of both DNSP network capability and proponent network service requirements.

**Key Message**

Without an interactive approach to confirm a workable project proposal following the submission of a Connection Enquiry, there is no surety that a workable "offer to connect" will result from the present NER obligation for an "offer to connect" to be made against a submitted "connection application".

[9] The likely impact of the Commonwealth Government's means test on eligibility for the PVRP is uncertain at this stage.

# Chapter 8 Contractual issues

## *8.1 Present position*

Contractual issues are covered by the general clauses and Schedules of a CA where drafted or by accepted standard documentation.

For larger generators' CAs have to be advised to NEMMCO with this advice, applying mainly to matters of concern relating to impacts on the transmission system (that is, the interconnected grid). Therefore NEMMCO is not concerned about constraints on the distribution system.

The CA is a document relating to the network connection only and in particular, it is not intended to cover matters relating to:

- a Power (or Energy) Purchase Agreement (PPA) which is negotiated separately with an Energy trader OR
- a "Network Support Contract" which may be negotiated between a DNSP and an EG to define any agreed network services sought by the DNSP and offered by the EG.

The transfer capacity and network services required by the EG and offered by the DNSP are key contractual considerations included in the CA together with the obligations and responsibilities of the parties in relation to these matters. Proponents in particular are interested in defining the minimum standards applicable to the network services to be provided by the DNSP.

Networks have an inherent performance capability and delivered serviced reliability which can not readily be changed. These are not easily quantified for a given set of connection assets – despite the keenness of proponents to include such numbers in the CA. Commonly used industry performance figures (such as the System Average Interruption Duration Index (SAIDI), the Customer Average Interruption Frequency Index (CAIFI), the number of line faults per 100km) generally provide an indication of the average performance capability of the network and may not meet the proponent expectations of being able to include quoted measures specific to their connection.

Surety of service provision is commonly stated in terms of the DNSP undertaking to apply "best engineering practice" in the design, construction, maintenance and operation of involved connection assets. This may not be seen by the EG proponent to be sufficiently specific for the CA requirements.

Communication and metering services may also be included in the CA, with them commonly having interdependent requirements. Metering information may need to be remotely accessible to the DNSP and NEMMCO with them possibly requiring to know the connection status and output level of the EG.

## 8.2 ENA Position by Class

ENA supports the need for a standard form CA to be developed and applied to micro/mini EG, with this being based on, and be similar to the standard or default Customer CAs.

ENA accepts that negotiated CA's are appropriate for medium and large EG installations and could be either a standard format offered by the DNSP or project specific, as negotiated by the proponent's agent and based on DNSP pro forma.

ENA notes that_CA's can clarify obligations from a contractual point of view but DNSP's cannot, opt out of the regulatory or statutory obligations. Therefore although financial penalties may be able to be contractually assigned, the regulatory obligation cannot.

| **Key Messages** |
| --- |
| ENA supports nationally consistent CAs for micro/mini EG. |
| ENA supports the view that minimum service standard obligations for services, as part of the existing regulatory requirements by the DNSP to the EG, do not need to be repeated in a CA |
| ENA submits that any risk to DNSP's obligations to provide network services and ensure power quality to other network users posed by the connection and operation of EG's should be covered by an appropriate requirement on the EG's involved. |

# Chapter 9 Operating Protocols

## 9.1 Present position

Micro/mini and low end small EG installations are generally connected within a customer's installation and hence to the LV network via the customer service connection. As such they are operated by the EG owner as part of a customer installation and hence do not require individual site arrangements to define the operating requirements.

Medium and large EG installations (along with high end small) involve connections to the MV (11 - 22kV or HV) distribution network or the sub transmission network respectively. Such connections may require specific network services and need suitably qualified and accredited personnel to complete installation, maintenance and operating work. The roles and responsibilities of the DNSP and EG relating to the provision and oversight of the connection are generally defined in a "HV Operating Agreement" as a supplementary document to the CA.

The HV Operating Agreement may include references to:

- the location and nature of the connection.
- the parties involved and their respective contacts.
- any particular requirements and commitments relating to the connection.
- the need to maintain records and advise the names of qualified personnel.
- procedures for the reciprocal notification of needed connection asset works and unexpected faults.
- an undertaking to synchronise scheduled maintenance works to minimise connection service interruptions.
- the need for annual forecasts of required transfer capacity and expected energy generation.
- any fees and payments applicable for requested switching operations or curtailment of network services.
- an agreed procedure or schedule to review each party's performance against the Operating and Connection Agreement requirements.

The Operating Agreement may also reference related documents such as:

- the Electrical Installation Safety Rules.
- an Asset Management Plan.
- Standard Operating procedures.
- schematic and wiring connection diagrams.

## 9.2 ENA Position

ENA agrees that the characteristics and connection arrangements for micro/small EG do not warrant the preparation of an installation specific Operating Agreement.

ENA also supports the negotiation of specific HV Operating Agreements as a relevant and an appropriate requirement to supplement the CA for medium and large EG installations, and notes that such Agreements are consistent with current practice for HV customer load connections.

**Key Messages**

ENA supports small, medium and large EG installations being subject to specific connection and operating requirements which should be defined as an operating protocol in an installation specific HV Operating Agreement.

ENA also supports an agreed standard proforma and contents list for the HV Operating Agreement to be developed to achieve consistency in connection arrangements for all DNSP's.

# Chapter 10 Contracts for Procuring Network Support Services

## *10.1 Existing Arrangements*

When it comes to network support provision by the EG DNSPs are concerned with the EG's availability and reliability.

It is expected that the Regulatory Test conducted by DNSPs would examine the best economic solution. For example, an operating expenditure payment to an EG for network support or a capital spend for network augmentation.

The default payment for network support should mirror the avoided cost of a network solution, and the nature of network support to be provided. Payments include a fixed annual/monthly charge where intermittent, short term support is sought or a combined availability/usage payment regime where extended support could be required with associated high fuel usage and costs (for example: to cover the loss of a transformer).

This Chapter expands on the general references to network support use and payments made previously in Section 5.3 of this paper.

### 10.1.1 Network Support Needs & Options

Network support refers to support given "to" the network by export or reduced demand/consumption or reserve supply capacity provided by a generator (see Definitions Attachment C).

The DNSP may seek such support as an option to relieve an identified network "constraint" (such as an overloaded line or transformer, below standard voltage and shortfall in transfer capacity to ensure "N-1" reliability). Such support may be contracted in lieu of committing to augment the network or as an interim service pending the completion of a required network augmentation.

Where network support is accepted from an EG, the DNSP's primary concern, as stated earlier is with the availability and reliability of the EG in being able to allow it to ensure the delivery of the DNSP's network service obligations capacity.

Network constraints and augmentation options are identified as part of the Planning and Development process and provide the basis for specifying the nature and capacity of the needed support.

### 10.1.2 Network support payments

Under the NER, DNSP's are required to identify and evaluate alternatives to network augmentation to address a network constraint and determine the most cost effective solution by the application of the Regulatory Test. The Regulatory Test is applied to network augmentation projects which exceed $1M in value and compares the derived Net Present Value of workable options to determine the least cost project.

The annualised value of the capital expenditure and operating/maintenance expenditures of the preferred network augmentation provide a "benchmark" for the annual operating expenditure which could be paid to an EG for the provision of an alternative support service. An alternative proposal must be demonstrated to be competitive with this cost, as well as provide a workable solution, as an outcome of the Regulatory Test assessment

### 10.1.3 Regulatory Test Reliability Limb

Network support services will be assessed under the reliability limb of the Regulatory test. The wording in relation to this limb of the test has a critical requirement in the use of the word "solely" in referring to the allowable network investment needed to meet the minimum network performance requirements.

This specific reference has the potential to adversely affect the assessment of alternatives options, such as EG, which can often introduce other benefits as a related consequence.

The above needs further considered and could be part of the foreshadowed Regulatory Test Review.

### 10.1.4 Service Target Performance Incentives

Where a "network augmentation" solution is displaced by, for example, a third party EG solution to address a customer load at risk scenario, there is inherent risk to the customers should this embedded generator cease operation after some period of operation or is designed to a lesser level of reliability[10].

DNSP's have an obligation to consider alternative solutions in a fair and reasonable manner. An EG solution could be deemed to be a fair and reasonable alternative to a line augmentation. The DNSP is exposed and subject to "service target performance incentives" for supply to their customers. Although a third party EG owner could be subject to an availability performance target the operation of the EG business remains independent of the DNSP. This means that the DNSP cannot have total control of assets providing the electricity service to their customers and is exposed to any penalty should the embedded generator fail to comply with its performance targets.

[10] Due to cost considerations, an EG proponent may choose to install a single larger generating unit in lieu of two smaller units of equivalent capacity, which in inherently more reliable.

## *10.2 ENA Position*

There needs to be consideration of having a service target performance incentive to provide the DNSP some form of protection against third party failure, given that the market is set up to encourage the development of alternative solutions to network augmentation such as EG.

**Key Messages**

DNSPs should not be penalised through 'performance incentives' when an alternative non-network solution with a higher risk profile is implemented in lieu of a network augmentation.

ENA notes that consideration needs to be given to the appropriate mechanisms to manage the reliability risks imposed by demand management projects so that distribution businesses are not disproportionately penalised for adopting demand management projects to defer network expenditure.

The following comments apply to network support services providers where the service is a long term arrangement.

### 10.2.1 Support Timing

Where a network support service is to be provided by an EG consideration should be given to the technical and performance characteristics of the plant and the time taken to complete the actions needed for the EG support services to become available. These include the completion of the application and connection procedures needed to secure a 'Connection Agreement' for a new plant installation plus the project approval, design, procurement and construction periods.

Generation plant proposals can result in significant environmental concerns such as noise, exhaust emissions and traffic. This may impact on the needed project assessment requirements which, along with plant delivery lead times, can have a significant affect on the "support available" date. This needs to be considered by both parties.

### 10.2.2 Network V Generation Reliability

A key consideration is the assessment of the needed and delivered supply reliability and how this may be affected by the relative availability of the network, generator and combination supply arrangement. For smaller and non critical loads "N" reliability may be acceptable to the DNSP whilst "N-1" (requiring full redundancy) may be needed to service larger and/or sensitive connections or meet licence compliance conditions.

The expected reliability of a supply system can be indicated from accepted availability figures and used in association with repair time allowances to determine the suitability of a proposed supported network (for details see Attachment D).

### 10.2.3 Repair time considerations

Whilst the supply availability measures discussed above indicate the overall performance, which can be expected from a particular class of supply asset, they do not allow for the timing or duration (repair time) of a failure event.

Repair times are generally accepted to be a working day (8 hours) or better for power lines and many days (or weeks or months) for plant such as transformers, motors and electrical machines – with a generating unit commonly comprising all three .

The need for periodic major plant maintenance can also affect the risk of "second" outages and result in an assessed need for duplication.

Hence, single power lines are commonly accepted as suitable for providing N supply reliability but at least two plant units (transformers, motors, generators) are needed to give N supply given the increased chance of supply failure occurring whilst a plant item is out of service awaiting repair or return to service from maintenance. This is the basis for the general DNSP requirements for two transformers to be installed in zone substations.

The risk of extended repair and major maintenance requirements can become a critical issue in assessing the acceptability of EG proposals to provide network support. Multi machine installation may be deemed necessary to allow for long potential repair times for a plant component failure. The interdependencies between the EG plant components (drive motors, generator units, connecting transformers etc) may enhance the consideration of this concern.

**Key Messages**

In the application of the Regulatory Test and in developing supply agreements, reliability performance measures need to take into account all three measures, namely availability, supply risk and repair time implications.

ENA supports the continuation of a regulatory approach which places non-network options, such as EG, on an equal footing with established network augmentation approaches.

### 10.2.4 Network Support Agreement

The above considerations should be reflected in a Network Support Agreement to define the network support services agreed between the NSP and the EG, along with any other relevant items. Such an Agreement may therefore include references to the following items:

- Network constraint and location (Feeder, Transformer, NMI).
- Legal entities contracting.
- Support service(s) needed or sought.
- Support services offered and agreed.
- Period/Term of the contract (e.g. over a summer peak period only).

- Fees payable by the network – which may take the form of fixed components ($/MW) (to assure an incentive to sign) and a variable component ($/MWh) (to assure an incentive to perform when called upon) and be based on the assessed costs of the preferred network alternative.

- Payment Terms.

- Methodology to determine impact on network load reduction after the call event.

- Minimum notice period of requested network support.

- Ancillary arrangements (e.g. surety of fuel supplies, refuelling arrangements, readiness testing etc).

- Operational contact details.

It is understood that individual micro/small EG installations will not generally contribute network support services. This position may vary for specifically designed large scale installation which would be subject to individual assessment and agreement in relation to the effects on the distribution supply network.

For medium and large installations, the Network Support Agreement will contractually and technically ensure the capability and availability of the EG where it is to be relied upon for Network support as an alternative to network augmentation.

The converse, being the availability of the network for energy import and the conditions under which it can be assessed, will be addressed in the Connection Agreement.

# Attachment A –Summary list of Key Messages

## *Pricing*

- Regulators need to ensure that an EG's connection is not subsidised by those not directly benefiting from the EG connection.
- Access cannot be guaranteed to be firm (that is; access guaranteed to be unconstrained 100 percent of the time).
- The regime should be "cost reflective" of all costs.
- ENA recommends further consideration be given to the application of DUoS charges, first mover issues and feed in tariffs.
- ENA notes that a number of studies have demonstrated that the installation of large scale PV may not benefit the performance of the electricity supply network.
- There is a need for consistency between pure generators and combined generator/load arrangements. This requires either a Rule change to back out of Section 6.1.4.
- Where network users embed generators to reduce their network load, requests for preserving capacity in the network (standby) should be subject to an appropriate charging regime.
- Alternatively, a once off fee should apply which would reflect all network related costs in accommodating a new EG unit including stand by capacity for delivery of purchased energy.
- The requirement for DNSPs to make avoided TUoS/DUoS payments to embedded generators should be removed from the Rules.
- ENA supports the use of network support payments to embedded generators, where the planning and Regulatory Test obligations under the Rules establish that such non-network solutions represent the most efficient means of alleviating a network constraint.

## *Technical Requirements*

- It may be beneficial to develop standard technical requirements for each generation class connections below 30 MW.
- Electricity networks are characterised by extensive distributed assets throughout the public domain such as powerlines, substations and underground cables. .
- There will be additional complexity and costs associated with the management of hazards and risks posed by the operation of embedded generators.
- In having an industry wide approach, the safety requirements established for each of the DNSP's cannot be compromised for any of the different classes of EG.
- Other than the micro EG class, the protection requirements for EGs can vary depending on the characteristics of the generating unit and the point of connection. However, harmonisation of protection requirements across jurisdictions and DNSPs is highly desirable to achieve efficiencies with respect to the ability for EG products and schemes to be connected in different parts within a network and in different networks; thereby minimising the costs of variations and modifications to proponents.
- ENA recognises that significant consideration needs to be given to tariff (particularly mandated in-feed arrangements), jurisdiction and individual DNSP requirements which can influence the choice of net and gross metering arrangements for EG connected within a customers installation.
- ENA's view is that the current protocol where the DNSP has the responsibility for fault level voltage and power quality on the distribution network and its impact on related networks be maintained to preserve the integrity of the network.
- ENAs firm position is that all costs incurred to ensure fault level voltage and power quality be recognised and should be fully recovered under the regulatory arrangements.

## *Application and Connection Processes*

- ENA intends to give consideration to the development of a standard procedure for the connection of micro, mini and relevant small EG

- Standard connection processes, including common procedures and uniform documentation should be adopted where possible, having regard to the differences classes of EG.

- ENA's view is that DNSPs need to be advised of all relevant detail relating to new EG installations (this includes; the location, capacity and type of each EG installation, the nominal capacity, the agreed generated performance standards, the required and agreed network services, the period of effect andany factors specific to the connection).

- Without an interactive approach to confirm a workable project proposal following the submission of a Connection Enquiry, there is no surety that a workable "offer to connect" will result from the present NER obligation for an "offer to connect" to be made against a submitted "connection application".

## Contractual issues

- ENA supports nationally consistent CAs for micro/mini EG.

- ENA supports the view that minimum service standard obligations for services, as part of the existing regulatory requirements by the DNSP to the EG, do not need to be repeated in a CA

- ENA submits that any risk to DNSP obligations to provide network services and ensure power quality to other network users posed by the connection and operation of EG's should be covered by an appropriate requirement on the EG's involved.

## Operating Protocols

- ENA supports small, medium and large EG installations being subject to specific connection and operating requirements which should be defined as an operating protocol in an installation specific HV Operating Agreement.

- ENA also supports an agreed standard proforma and contents list for the HV Operating Agreement to be developed to achieve consistency in connection arrangements for all DNSP's.

## *Contracts for Procuring Network Support Services*

- DNSPs should not be penalised through 'performance incentives' when an alternative non-network solution with a higher risk profile is implemented in lieu of a network augmentation.

- ENA notes that consideration needs to be given to the appropriate mechanisms to manage the reliability risks imposed by demand management projects so that distribution businesses are not disproportionately penalised for adopting demand management projects to defer network expenditure.

- In the application of the Regulatory Test and in developing supply agreements, reliability performance measures need to take into account all three measures, namely availability, supply risk and repair time implications.

- ENA supports the continuation of a regulatory approach which places non-network options, such as EG, on an equal footing with established network augmentation approaches.

# Attachment B – State/Territory Regimes

## Australian Capital Territory

**Summary**

There are no specific provisions in the ACT for embedded generation. ActewAGL largely operates under the provisions of the *National Electricity Rules*, for all generators, including unregistered generators. However, feed-in tariff arrangements apply for electricity sold back into the grid and a renewable energy target (RET) applies.

### Guidelines

ActewAGL are currently developing a Guideline/Information package for embedded generation proponents, to assist in the application and connection process. This package is likely to include credits for avoided TUOS and the possibility of offsetting a load with generation at the same connection point.

### Other Initiatives

The ACT's "Climate Change 2007-2020" initiative includes a renewable energy target (RET) which requires electricity retailers to source 10 per cent of their energy from renewable sources by 2010 and 15 per cent by 2020. Also, a feed-in tariff arrangement has been adopted whereby renewable power sold back into the grid is credited at a higher rate than energy bought from the retailer.

## New South Wales

**Summary**

In New South Wales, the arrangements and treatment of embedded generation are embodied within the overall network concept of demand management, which requires proponents of network augmentations to assess options to implement alternative demand management strategies. Further, a "Climate Change Fund" and RET indicate that the State Government's policy is to encourage embedded generation based on renewable energy.

### NSW Legislation

The NSW *Electricity Supply Act 1995* and regulations place a statutory requirement on all licensed electricity distributors to explore demand management options. Specifically, distributors are required to investigate the cost effectiveness of implementing demand management strategies which may allow distribution network augmentation work to be deferred (or avoided). The requirements of the NSW Act are mirrored in each of the distributor's licences. These conditions include a requirement to carry out investigations as to whether it would be cost effective to implement demand management strategies.

### NSW Demand Management Code of Practice

The purpose of the Demand Management Code of Practice ("the Code") is specifically directed, though not restricted, to covering DG, energy efficiency and load management.

The Code's objective is to provide guidance to electricity distributors on how to comply with licence obligations relating to consideration of demand management solutions when assessing network augmentations.  The Code is not mandatory but acts as a guideline in formulating Network Management Plans, which are published by each of the Distributors and endorsed by the Minister as part of the distribution licence.

### Independent Pricing and Regulatory Tribunal (IPART) Inquiry

IPART undertook an inquiry into the potential of DG options to enhance electricity network capacity and reliability. The review of DG formed part of a general enquiry on the role of demand management in the future provision of State energy services. The IPART terms of reference included an assessment of the potential for greater use of DG options and the identification of barriers to development. The outcome was that, for most non-technical purposes, embedded generation is considered as a form of Demand Management.  The IPART *Final Report of Inquiry into the Role of Demand Management and other options in the Provision of Energy Services*, October 2002, is available at the IPART website.

### Other Initiatives

In 2005, the NSW Department of Energy and Utilities introduced an Energy Savings Fund to provide financial support for marginal projects or untrialled technologies. The fund provides $200 million over five years for projects which will save energy and reduce peak electricity demand.

The purpose of the Energy Savings Fund is to:

- reduce overall electricity consumption in NSW and related greenhouse gas emissions,
- reduce peak electricity demand,
- stimulate investment in innovative measures, and
- increase public awareness in energy savings.

The first round of the Energy Savings Fund was held from September-October 2005, and awarded $15 million to about 20 projects. The second round of the fund, awarded in September-November 2006, allocated a total of $13 million to 29 energy generation, efficiency and education projects.

Following the 2007 State election, this fund is to be incorporated into a Climate Change Fund, totalling $310 million over five years, with similar objectives. The fund includes a $40 million Renewable Energy Development Fund for pilot and demonstration projects such as solar and geothermal power stations.

The NSW government has also introduced legislation requiring 10 percent of electricity consumed in NSW by 2010 and 15 percent by 2020 to be sourced from renewable energy developments. This initiative is expected to stimulate an additional 7 250 GWh of new renewable energy generated by $3.5 billion in investment.

## Northern Territory

**Summary**

There are no specific embedded generation related obligations applying to the NT nor does the Territory have any incentive scheme for the adoption of renewable energy sources.

### NT Legislation

The *Electricity Reform Act 2000* provides that a licence is required for the generation of electricity but reflects Government policy that a full licensing regime would be overly onerous on small re-sellers of electricity, so has decided to grant an exemption from the need to be licensed under certain circumstances.

### NT Electricity Networks (Third Party Access) Code

Under Clause 30 of the Code an access applicant may be required to make a capital contribution towards the augmentation of the network system if the extension is not commercially viable without the capital contribution. There is no provision providing for separate treatment for embedded generators or for applicants on the basis of their capacity to use or supply electricity.

PowerWater Corporation is the prime provider of electricity on the NT. Embedded generators are able to enter into a PV network agreement with the Corporation in relation to connection and for the purchase of power. There are no subsidies provided by PowerWater under these arrangements.

## Queensland

**Summary**

There are no specific embedded generation provisions in place in Queensland beyond the *National Electricity Rules* requirements. However, the Government has adopted a feed-in tariff scheme and a RET applies.

### Queensland Legislation

In accordance with section 43 of the *Electricity Act 1994* a network business must allow, as far as is technically and economically practicable, a generator to connect supply or take electricity from its supply network on a fair and reasonable basis provided the network is capable of safely being used to connect, taking into account among other considerations, the network capacity.

### 2005-10 Queensland Electricity Distribution Price Determination

The Queensland regulator, the QCA, considered demand management (including embedded generation) as part of the 2005-10 Queensland Electricity Distribution Price Review. The QCA determined that providing specific regulatory framework incentives for demand management (such as those in NSW) was not warranted, as Queensland distribution businesses are regulated under a revenue cap.

The QCA did indicate that demand management initiatives were a potential source of efficiency in both capital and operating expenditure for ENERGEX and Ergon Energy. ENERGEX was granted $14.5 M of demand side OPEX in the current determination, primarily to reduce asset utilisation levels to those recommended in the Somerville report.

### Queensland Electricity Industry Code

The Queensland Electricity Industry Code is made under the Electricity Act 1994, and requires each distributor operating in the state to complete an Annual Network Management Plan.

Both the ENERGEX and Ergon Energy Network Management Plans include specific references to embedded generation.

The *ENERGEX Negotiated Customer Connection Agreement* provides for an *ENERGEX Agreement for Parallel Generation*. Specifically, this Agreement provides for the installation, operation and interconnection of the customer's generating system at a connection point to the supply network, at the customer's own cost. This is subject to compliance with law, technical requirements and good electricity industry practice. ENERGEX has also developed its own Network Demand Management Strategies, incorporating embedded generation which is specifically referred to in the ENERGEX Annual Network Management Plan.

Ergon Energy has developed a standard Network Agreement for connection of AS4777 compliant inverter energy systems for EGs up to 10 kW single phase connections and 30 kW three phase connections.

### Other Initiatives

From 1 July 2008, the Queensland Government introduced "feed-in tariffs" which will pay consumers for energy they contribute to the electricity grid from solar panel systems. Metering arrangements for these are the 'net' scheme excluding controlled load. The Government has also adopted a RET of 10 percent by 2020.

## South Australia

**Summary**

South Australia has made specific provisions for accommodating embedded generators into its electricity networks including rules for the State's electricity utility to follow in connecting DG providers and for paying feed-in tariffs for electricity supplied into the network. The State is also funding stand by pilot programmes for specific demand management projects including embedded generation.

### South Australian Electricity Distribution Licence

The South Australian Electricity Distribution Licence requires network businesses, before undertaking any significant expansion of the distribution network, to investigate whether it would be cost effective to avoid or postpone the expansion by implementing demand management measures, including reduction of demand.

The Licence also requires ETSA Utilities to:

- undertake demand management activities as directed by the regulator, ESCOSA, for which it has received funding through an electricity distribution price determination,
- prepare reports on demand management investigations and measures carried out, and
- comply with any applicable guideline relating to the implementation of licence obligations for demand management.

### 2005-10 South Australian Electricity Distribution Price Determination

The 2005-10 Electricity Distribution Price Determination applying to ETSA Utilities includes funding for a number of specific demand management projects and pilots. A total of $20 million in operating expenditure has been allocated for ETSA Utilities to develop capabilities and undertake network demand management activities.

Programmes include initiation of a standby generation pilot programme. The first stage of this programme would be an assessment of the technical and environmental barriers for connecting and operating existing embedded equipment in parallel with the distribution network. The generators could then be used to provide network support (if required) and/or generating capacity during peak load periods. In the first instance, this assessment should be based on 5 large customers, with standby generation equipment identified in the North Adelaide area.

These specifically funded demand management projects are intended to operate outside of any demand management incentive scheme and not to affect the revenue paid to ETSA Utilities for normal demand management activities.

The Electricity Distribution Price Determination also includes an efficiency carry-over mechanism for both capital and operating expenditure. Capital efficiency carry-over mechanisms can enhance the economic case for demand management projects, including embedded generation projects that defer network augmentation, particularly late in the regulatory review period. South Australia is the only jurisdiction to apply a carry-over mechanism for all capital expenditure.

**ETSA Utilities Service and Installation Rules**

The ETSA Utilities Service and Installation Rules are intended to assist customers and electrical contractors by detailing:

- the method and type of supply from ETSA Utilities' distribution network,
- the requirements for electrical installations connected to ETSA Utilities' distribution network,
- some of the customers' obligations relating to that supply.

The Service and Installation Rules set out requirements and processes for supply application, connection, and disconnection for all customers, including embedded generators. The Rules also set out the technical requirements for the connection of an embedded generator to ETSA Utilities' network.

**South Australian Electricity Distribution Code**

The South Australian Electricity Distribution Code sets out rules that ETSA Utilities and embedded generation proponents must follow in respects of connection applications, offers to connect, and the levying of fees and charges on embedded generators.

The Code includes differentiated obligations for small and large embedded generators, including a limitation that only allows the levying of upstream augmentation changes on large embedded generators (being embedded generators that do not comply with AS4777). The Code also sets out time limits for the progress of stages of a connection application, and some technical requirements embedded generators must satisfy.

**ETSA Utilities Customer guide for small embedded generators**

ETSA Utilities has developed a Customer guide for both small and large embedded generators to assist embedded generation proponents understand their rights and obligations with respect to the connection and use of system. For small generators, this guide is supported by a standard small embedded generation connection agreement, intended to streamline the connection process.

**Guideline Number 12: Demand Management for Electricity Distribution Networks**

The regulator in South Australia, ESCOSA, has planning and reporting requirements in place similar to those in NSW, set out in its Electricity Industry Guideline No. 12 *Demand Management for Electricity Distribution Networks*. This Guideline was recently reviewed by ESCOSA, with a number of changes being made to the Guideline.

The Guideline requires ETSA Utilities to consider non-network alternatives before commencing augmentation projects that have an estimated capital cost of $2 million or more and to:

- publish an Electricity System Development Plan (including Sub-transmission and Regional Development Plans) annually and maintain a Register of Interested Parties;
- undertake consultation in relation to Eligible Major Network Projects, including an assessment of the suitability of particular projects for deferral through demand management solutions, as well as to develop and maintain expertise in system support options within ETSA;
- consider non-network alternatives before commencing an Eligible Major Network Project; and
- annually report its compliance with the Guideline and other demand management requirements.

**Other Initiatives**

The South Australian Government introduced "feed in tariffs", which will pay consumers for energy they contribute to the electricity grid from solar panel systems, in September 2006.

## Tasmania

**Summary**

Embedded generation is incorporated as an option under the State's demand management planning requirements.

**Tasmanian Legislation**

The *Electricity Supply Industry Act 1995* makes it a condition of an exclusive retail licence that a retailer provides electricity supply services to a customer. As Aurora Energy Pty Ltd is the sole network provider in Tasmania this amounts to an obligation to connect. Aurora currently waives costs associated with the basic connection of a photo voltaic unit to the network. The company also waives the cost of net metering equipment.[11]

### Tasmanian Electricity Code

Under the Tasmanian Electricity Code a network business must provide an annual Distribution System Planning Report to the Regulator detailing how it plans to meet predicted demand and improve reliability to customers over the next five years. The report must include, among other requirements, a description of feasible options for meeting forecast demand, including opportunities for embedded generator and the contributions available from network providers to embedded generators to reduce forecast demand and defer or avoid augmentation. Further, annual reporting also requires the network provider to identify feasible options for embedded generation.

In accordance with Section 8.7.2 of the Code a network provider must have in place a procedure approved by the Office of the Tasmanian Energy Regulator to deal with connections of embedded generators.

## Victoria

**Summary**

Victorian regulations specifically accommodate the incorporation of embedded generation through demand management planning requirements, obligations on distributors for connection; pass through of costs arising from payments to EGs for avoided charges, and provisions for capital contribution charges where connection of the DG to the network is required. New feed-in tariff legislation can be expected to encourage embedded generation and a RET applies.

### Victorian Distribution Licence

The Victorian Distribution Licence includes an obligation on distribution businesses to comply with all applicable orders, codes and guidelines issued by the Essential Service Commission. This includes Guideline 15: Connection of embedded generators.

With respect to embedded generators, the Licence includes an obligation to offer connection services to embedded generators within 65 business days.

### 2006-10 Victorian Electricity Distribution Price Determination

The 2006-10 Victorian Electricity Distribution Price Determination allows the pass through of costs that arise as payments to embedded generators for avoided distribution systems and avoided TOUS charges.

### Victorian Electricity Distribution Code

[11] The distribution network in Tasmania, starts at the load side of the 11, 22 & 33kV distribution feeders – the transmission network assets includes the 11, 22 & 33kV (& 44kV) switchgear at the connection sites and therefore connections of embedded generation to the distribution network is limited to under 10MVA.

Victorian distribution businesses are required to comply with conditions set out in the Victorian Electricity Distribution Code which are very similar to those in the *National Electricity Rules*. The distribution businesses are required to publish annually:

- A joint Transmission Connection Planning Report, including opportunities for embedded generation and demand management; and

- Individual Distribution System Planning Reports including opportunities for embedded generation and demand management.

The Reports are intended to allow interested parties to submit proposals for alternatives to network augmentation, and must include information about feasible embedded generation and demand management options that could meet forecast demand as an alternative to network expenditure. This differs from South Australian approach which actively seeks proposals through a tendering process.

The Distribution Code also places obligations on embedded generators in respect of generating unit requirements, frequency, power quality and fault levels.

**Guideline15: Connection of Embedded Generators**

Guideline 15: Connection of Embedded Generators, supplements obligations in the Victorian distribution licences and code.

The Guideline sets out rules for the development of a standard connection agreement for small generators, information provision, negotiation of connection and any avoided distribution system payments for larger generators, and calculation of avoided TUOS charges. It also states (Clause 3.3.2(b)(1)(A)) that DG connection may attract a capital contribution referable to the present value of incremental costs of shallow augmentation (defined as installation on network assets and any augmentation of the distribution system up to and including the first transformation in the system in respect of the embedded generator) required for the connection of the embedded unit.

**Other Initiatives**

The Victorian Government has introduced "fair price for renewables" legislation into parliament to simplify the rules around feed-in tariffs and ensure all renewable technologies with an installed capacity up to 100 kW are included.  The Government has also adopted an RET of 10 per cent by 2016.

## Western Australia


**Summary**

In Western Australia, the primary driver for demand management and embedded generation (as with other jurisdictions) comes from the requirement to minimise the cost of providing network services by having to consider "alternative options". Western Power is currently developing a demand management and embedded generation strategy in response to strategic imperatives driven by senior management. WA has a RET for renewable energy sources.


In WA the regulatory regime for electricity distribution is governed by two main instruments, the Electricity Network Access Code 2004, and the Wholesale Electricity Market Rules, administered by the Economic Regulation Authority (ERA) with the Independent Market Operator (IMO) operating the market. At the commencement of the Access Code the only regulated network in WA was the Western Power South West Interconnected Network.

### WA Electricity Networks Access Code

The Western Australian *Electricity Networks Access Code 2004* is the instrument for regulating access to network infrastructure.

There are two provisions in the Code that relate to major network augmentations including,

1. Subchapter 6.2 – Calculation of Service Provider's Costs. More specifically clauses 6.52 to 6.55 relating to the "New Facilities Investment Test" (NFIT); and,

2. Chapter 9 – Regulatory Test, where the Network Operator must establish to the ERA that it has satisfied the test.

"New Facilities Investment Test"

In the Code new facilities are defined as,

> *Any capital asset developed, constructed or acquired to enable the service provider to provide covered services including assets required for the purpose of facilitation of competition in retail markets for electricity.*

The need for new facilities is primarily driven by the need to augment the existing transmission network to enable,

- Connection of new generation and loads;
- Cater for load growth; and,
- All other facilities required to support safe, reliable and secure power transfer between generators and loads, which may include reactive power compensation, reactors, etc.

Prior to the inclusion of new facilities into a covered network, the ERA must be satisfied that the NFIT is satisfied. The Network Operator must establish that its new facility investment efficiently minimises total costs of providing covered services; and, one or more of the following conditions is satisfied (Clause 6.52(b) refers).

(i) Either:

A. The anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. If a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold – the modified test is satisfied;

or

(ii) The new facility provides net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

(iii) The new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

Regulatory Test

The Regulatory Test applies only to proposed major augmentation projects, i.e. projects greater than $15m in value. The objectives of the Regulatory Test are:

1) To ensure that before a service provider commits to a proposed major augmentation to a covered network, the major augmentation is properly assessed to determine whether it maximises the net benefit after considering alternative options; and

2) To provide an incentive to a service provider, when considering augmentation to a covered network, to select the option (which may involve a major augmentation or may involve not proceeding with an augmentation at all) which maximises the net benefit after considering alternative options; and

   i) To minimise:

   ii) Delay to projects and other developments; and

   iii) Administrative and regulatory costs; and

   iv) Any other barriers to the entry of generators and consumers into the electricity market, arising from the application of the Regulatory Test.

Western Power submitted an "Amended Proposed Access Arrangement" to the ERA on 2 April 2007 for consideration. In its "Further Final Decision on the Proposed Access Arrangement for the South West Interconnected Network" the ERA approved the Access Arrangement which came into effect as of 1 July 2007. Under the Access Arrangement, major network augmentation projects are submitted into the Regulatory Test process as stand alone projects with project specific consultations required for each project.

According to the Code, the Regulatory Test is deemed to be satisfied if the ERA is satisfied that (Clauses 9.20 refers),

- The service provider's statement that the proposed major network augmentation maximises the net benefit after considering alternative options is defensible;
- The service provider has applied the Regulatory Test properly to each major augmentation, i.e.
    - it has used reasonable market development scenarios which incorporate varying levels of demand growth at relevant places; and,
    - using reasonable timings, and testing alternative timings, for project commissioning dates and construction timetables for the major augmentation and for alternative options

    and
- the consultation process conducted by the service provider meets the criteria set out in the Code.

**Capital Contribution**

Under Chapter 5 of the Code the Capital Contribution Policy does not require a user to make a capital contribution in respect of part of a "new facility investment" which meets the "new facility investment" test as described above. Otherwise capital contributions apply as set out in the Code.

**Discounted Price Arrangements for DG**

The Code also provides for discounted pricing arrangements to apply to embedded generation plants under Clause 7.10. This provision requires the service provider to provide a discounted tariff reflecting any reduction in its costs which arise as a result of the entry of the DG plant into the covered network. The discounted amount can be recovered from other users through a reference tariff.

**Wholesale Electricity Market Rules**

The *Wholesale Electricity Market Rules* establish the rules for participation in the market and require endorsement by the ERA. The rules set out an approach for considering alternatives to major augmentation (investments greater than $15m).

Where required under the Access Code, the network operator, Western Power in WA, must notify the IMO of the nature of the proposed major augmentation, including estimated costs. The IMO then calls for expressions of interest for alternatives to the network augmentation. Where an alternative service provider submits a viable proposal that is less than 50% greater than the network service provider's estimated costs, then the IMO must carry out a tender process.

Under the tender process Western Power must notify the IMO of the nature of the opportunity for network support generation or demand side management to compete with transmission or distribution upgrade. The notification must include:

a) a specification of the services that would be required from the facility including:

    i. the maximum active and reactive power quantities required, specified in MW and MVAr;

    ii. the estimated number of hours per year that the services would be required; and

    iii. the required period of notice to call upon the services;

b) the location at which the facility would need to connect to the relevant network;

c) the Network Operator's estimate of the costs involved in connecting a generation facility that could provide the services specified in (a) from the location specified in (b);

d) the time by which the facility is required to be in service; and

e) the Network Operator's estimate of the cost of an augmentation to the Network that would provide the services.

Network Control Services are services "provided by embedded generation or demand side management that can be substitutes for an upgrade to a transmission or distribution network"[12]. Once the IMO has been notified of the opportunity for Network Control Services that could potentially compete with a transmission or distribution network upgrade then the IMO calls for expressions of interest for options other than augmentation.

If, as a result of a tender process a generation or demand-side option is selected, the successful tenderer must enter into a Network Control Service Contract with the IMO for 10 years.

The IMO then calls for expressions of interest for alternatives to the network augmentation. Where an alternative service provider submits a viable proposal that is less than 50 per cent greater than the network service provider's estimated costs, then the IMO must carry out a tender process. If, as a result of a tender process a generation or demand-side option is selected, the successful tenderer must enter into a Network Control Service Contract with the IMO for 10 years.

All network augmentations that are below $15 million, or where a network alternative is not available, must satisfy the New Facilities Investment Test, which is set out in the Electricity Networks Access Code.

**Other Initiatives**

The WA Government has also adopted an RET of 15 per cent by 2020 with details to be confirmed.

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[12] *Wholesale Electricity Market Design Summary*, Office of Energy, Government of Western Australia, October 2004.

## Embedded Generation - regulatory obligations and instruments in each jurisdiction

| Jurisdiction | Distribution Licence | Distribution Code | Current Price Determination | Other instruments(legislation, guideline, code) |
|---|---|---|---|---|
| **Australian Capital Territory** | | Industry Codes and Technical Codes covering distribution apply also to embedded generation. | | ActewAGL is in the process of preparing Guidelines/Information Package for the proponents of embedded generation. Subject to internal approvals, guidelines are expected to include credits for avoided TUOS and possibility of offsetting a load and generation (with some conditions) connected to the same network point. |

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| **New South Wales** | | Embedded generation is largely treated as negative demand. | D-Factor mechanism<br><br>Embedded generation is generally considered as part of the provisions for dealing with demand management generally.<br><br>The requirement to pass through avoided TUOS in full applies only to EG. | NSW Electricity Supply Act<br><br>Electricity Supply Act 1995 and Regulation place a statutory requirement on all licensed electricity distributors to explore demand management options. These obligations are mirrored in each of the distributors licences under Licence Conditions.<br><br>Code of Practice for Demand Management<br><br>Non-mandatory code to assist distribution businesses in interpreting the broad requirement to investigate DM and DG options in the NSW distribution licence.<br><br>Climate Change Fund (formerly the Energy Savings Fund)<br><br>The NSW Department of Environment and Climate Change administered fund to provide |

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| | | | | financial support for marginal projects or untrialled DM, EG and energy efficiency technologies. $200 million over 5 years.<br><br>The Market Operations Rule No.3 (NSW Rules for Electricity Metering)<br><br>Sets out metering requirements for embedded generators. |
| **Northern Territory** | | | | NT Electricity Networks (Third Party Access) Code covers all proponents wanting to use distribution network including embedded generators |

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| **Queensland** | A distribution authority (ie licence to operate in a distribution area in Queensland) requires compliance with:<br><br>• Electricity Act (1994) Qld<br>• Electricity Regulations (2006) Qld<br>• QCA Determination<br><br>Sect 42 (d) requires an entity to consider demand side options. | **Queensland Electricity Industry Code**<br><br>Requires each distributor to complete an Annual Network Management Plan.<br><br>Both the ENERGEX and Ergon Energy Network Management Plans include specific references to embedded generation. | ENERGEX granted $14.5M of DM-related OPEX, primarily to reduce asset utilisation levels to those recommended in the Somerville report. | **Electricity Act 1994**<br><br>Requires a network business to allow, as far as is technically and economically practicable, a generator to connect supply or take electricity from its supply network on a fair and reasonable basis provided the network is capable of safely being used to connect, taking into account among other considerations, the network capacity.<br><br>ENERGEX has also developed a Negotiated Network Customer Agreement which provides for the installation, operations and interconnection of the customer's generating system at a connection point to the supply network, at the customer's own cost. |

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| **South Australia** | Distribution Licence<br><br>Requires ETSA Utilities to investigate non-network options before undertaking significant expansion of the network. The Licence also requires ETSA to comply with applicable codes and guidelines relating to the implementation of licence obligations for demand management. | South Australian Electricity Distribution Code<br><br>The SA Electricity Distribution Code sets out rules that ETSA Utilities and embedded generation proponents must follow in respects of connection applications, offers to connect, and the levying of fees and charges on embedded generators. | 2005-10 South Australian Electricity Distribution Price Determination<br><br>Includes $20 million funding for specific DM initiates, including a standby generation pilot.<br><br>Efficiency carry-over<br><br>There is an efficiency carry-over mechanism in place for all capex and opex efficiencies. | ESCOSA Guideline 12 – Demand Management for Electricity Distribution Networks<br><br>Guideline 12 requires ETSA to consider DM solutions to defer network expenditure. Embedded generation is often considered as the DM alternative.<br><br>ETSA Utilities Service & Installation Rules<br><br>The Service and Installation Rules set out requirements and processes for supply application, connection, and disconnection for all customers, including embedded generators. The Rules also set out the technical requirements for the connection of an embedded generator to ETSA Utilities' network.<br><br>ETSA Utilities Customer Guide to |

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| | | | | Embedded Generation<br><br>This Customer guide in intended to assist embedded generation proponents understand their rights and obligations with respect to the connection and use of system. For small generators, this guide is supported by a standard small embedded generation connection agreement, intended to streamline the connection process. |
| **Tasmania** | Tasmanian Electricity Licence<br><br>Licence requires compliance with the Tasmanian Electricity Code. | Tasmanian Electricity Code<br><br>The Tasmanian Electricity Code requires the network business to provide an annual Distribution System Planning Report to the Regulator detailing how it plans to meet predicted demand and improve reliability to customers over the next five years, including a description of feasible options for meeting forecast demand through embedded generation as | | Aurora waives the cost associated with the basic connection of a Solar unit to the distribution network. We also waive the cost of the Net-Metering equipment. This is mainly done for promotional purposes and this arrangement is expected to be reviewed in the future. |

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| | | an alternative to network augmentation.<br><br>The Code also requires Aurora to have in place a procedure approved by the regulator to deal with connections of embedded generators. | | |
| **Victoria** | Victorian Distribution Licence<br><br>The Victorian Distribution Licence includes an obligation on distribution businesses to comply with all applicable orders, codes and guidelines issued by the Essential Service Commission. This includes Guideline 15: Connection of embedded generators.<br><br>With respect to embedded generators, the Licence includes an obligation to offer connection | Victorian Electricity Distribution Code<br><br>The Code requires network businesses to push annual planning reports to allow proponents to submit proposals for alternatives to network augmentation.<br><br>The Code also imposes obligations on embedded generators in generating unit requirements, frequency, power | 2006-10 Victorian Electricity Distribution Price Determination<br><br>The Determination allows the pass through of costs that arise as payments to embedded generators for avoided distribution systems and avoided TOUS charges. | Guideline 15 – Connection of Embedded Generators<br><br>This Guideline sets out  out rules for the development of a standard connection agreement for small generators, information provision, negotiation of connection and any avoided distribution system payments for larger generators, and calculation of avoided TUOS charges.<br><br>Tariff Order |

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| | services to embedded generators within 65 business days. | quality & fault levels. | | Includes charges for distribution services and augmentation required. |
| **Western Australia** | | WA Electricity Networks Access Code<br><br>The Code applies a "new facilities investment test" and a "Regulatory Test" (for augmentations over $15m) which must be satisfied prior to inclusion of new facilities into the network. For investment over $15m Western Power must notify the IMO of the details of the proposed project. The IMO then calls for expressions of interest for options other than augmentation. | | Wholesale Electricity Market Rules<br><br>For proposed network augmentations over $15m the Electricity Market Rules set out the details required for submission to the IMO for consideration of options other than the augmentation of the network. |

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| | | Under the Code embedded generators that meet the test(s) attract discount pricing arrangements which require the service provider to apply a discounted tariff reflecting the reduction in costs resulting from entry of the DG into the network. Further, where a user of the covered network is a “new facility investment” now capital contribution charges apply. | | |

# Attachment C - Definitions

The following definitions of terms relevant to the consideration of EG have been taken from the glossary at chapter 10 of the National Electricity Rules and other sources,

***Australian Standard*** The AS 4777 series relates to the various requirements associated with "Grid connection of energy systems via inverters". It may be useful in definition of classes of embedded generation.

***Avoided TUOS*** - The matter of avoided TUOS is treated in the NER as follows[13]:

(h) A *Distribution Network Service Provider* must pass through to a *Connection Applicant* the amount calculated in accordance with paragraph (i) for the locational component of *prescribed TUOS services* that would have been payable by the *Distribution Network Service Provider* to a *Transmission Network Service Provider* had the *Connection Applicant* not been *connected* to its *distribution network (*'avoided charges for the locational component of *prescribed TUOS services*').

***Embedded generating unit*** - A *generating unit connected* within a *distribution network* and not having direct access to the *transmission network*.

***Embedded Generator*** - A *Generator* who owns, operates or controls an *embedded generating unit*.

***Entry charge*** - The charge payable by an *Embedded Generator* to a *Distribution Network Service Provider* for an *entry service* at a *distribution network connection point*.

***Entry service*** - A service provided to serve a *Generator* or a group of *Generators*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*.

***Exit service*** - A service provided to serve a *Transmission Customer* or *Distribution Customer* or a group of *Transmission Customers* or *Distribution Customers*, or a *Network Service Provider* or a group of *Network Service Providers*, at a single *connection point*.

***Export energy*** in the context of embedded generation is energy generated by a Distribution Network User which is exported by the user into the distribution system. By extension (and from references to importing regions in the Rules) *import energy* is that energy received into the Distribution Network.

***Import energy*** – When power flows from the grid into the EG.

***Generator*** - A person who engages in the activity of owning, controlling or operating a *generating system* that is *connected* to, or who otherwise *supplies* electricity to, a *transmission* or *distribution system* and who is registered by *NEMMCO* as a *Generator* under Chapter 2 and, for the purposes of Chapter 5, the term includes a person who is required to, or intends to register in that capacity.

[13] NER Clause 5.5 Arrangements relating to Distribution Networks from sub clause (h)

**Islanding** - where a generator or generating system continues to supply customer load supplied from the network and the generator is disconnected from the network

**LV Network**: Network less than 1,000 Volts

**MV Network:** Network greater than 1,000 Volts but less than 35,000 Volts

***Market generating unit-*** A *generating unit* whose *sent out generation* is not purchased in its entirety by the *Local Retailer* or by a *Customer* located at the same *connection point* and which has been classified as such in accordance with Chapter 2.

***Negotiated use of system service -*** A *use of system service* in respect of which:

(a) a *Connection Applicant* may negotiate with a *Transmission Network Service Provider*;

(b) an *Embedded Generator* may negotiate with a *Distribution Network Service Provider*; or

(c) a *Market Network Service Provider* may negotiate with a *Distribution Network Service Provider*,

in accordance with clauses 5.4A(f)(3) or 5.5(f)(3).

**NER**: National Electricity Rules

***Network support*** is a term commonly used to refer to support BY an embedded generator TO the connected network by generator export or effectively reduced demand / consumption due to an embedded generator.

*Sent out generation* **-** In relation to a *generating unit,* the amount of electricity *supplied* to the *transmission* or *distribution network* at its *connection point*. (see Export)

**Reclose –** if an operation trips part of the network then an automatic close of that section of the network will occur after a defined time delay. This delay will vary for different parts of the network. The embedded generator must be disconnected from the network before any reclose operation takes place.

***Shallow and Deep connection*** arrangements and cost recovery refer to the provision and use of system capacity to allow connection. A *"shallow"* connection regime generally involves payment of charges (or provision of equipment[14]) by the connecting party for equipment needed just to connect to the local part of the network. It implies that augmentation "further upstream" is the responsibility of the NSP. *"Deep"* connection arrangements would, by contrast, include recovery of costs from the connecting party of network augmentation further within the network made necessary by the proposed connection.

[14] Energy Australia notes that it adopts the NSW contestability rules for the design and construction of the shallow/dedicated assets though this is not compulsory. It notes that the fee structure is covered by the NER.

In the UK context, an Ofgem consultation document[15] included the following more specific discussion:

"Deep connection charges involve a one off, up front payment. The charges include the costs of replacing equipment associated with protecting the network or with voltage control, up to the boundary of the distribution network. Where fault levels are increased above the rating of installed equipment, the cost of replacing that equipment would be included in the charge. By contrast, shallow connection charges involve paying for the assets specifically required for the connection, usually up to the first transforming point. The remaining reinforcement costs, if any, are regarded as general load growth. They are recovered through use of system charges."

There is further discussion of "shallower" connection charges – "only in relation to dedicated connection assets".

The NER definitions include definitions for *augmentation* – works to enlarge a network, or increase the capacity of a network to transmit or distribute active energy and a subset, *extension*, being "an augmentation that requires the connection of a power line or facility outside the present boundaries of the … network, owned, controlled or operated by a Network Service Provider."

If not stated in this Attachment the definitions per the NER will apply.

[15] Ofgem – Embedded generation: price controls, incentives and connection charging – A preliminary consultation document, available at http://ofgem2.ulcc.ac.uk/temp/ofgem/cache/cmsattach/40_27sep01.pdf

# ATTACHMENT D Assessment of Expected Network versus Generation Reliability in terms of Availability and Supply Risk

Availability can be quoted as a percentage or per unit figure, being typically 99% (0.99) for power lines and 90-95% (0.9 – 0.95) for generators.

The outage, or loss of supply risk, is calculated as being (1 – availability) for a single installation and the multiple of the individual factors for a multi component (a, b, c …n) system, for example; (1 – a) x (1 –b) x (1 – c)…x (1- n).

Hence as the calculation in the separate box below indicates the measure used for reflecting the level of reliability, be it availability or supply risk has a bearing on what is acceptable. Outcomes that are acceptable on the basis of availability (99%) may be perceived as unsatisfactory in terms of supply risk(3.5 days per year)

**Availability & Supply Risk For Network Augmentation v Generator Options**

The relative outage risk for adding a second transmission line or adding a generator to support an existing single (radial) transmission line supply becomes:

i) duplicate line risk = (1-0.99)(1-0.99) = 0.01 x 0.01 = 0.0001 or 0.01% which improves the availability from 99% (87.60 hours per year) to 99.99% (less than 1 hour per year supply risk)

ii) generator with 90% availability plus a single line with 99% availability = (1-0.90)(1-0.99) = 0.10 x 0.01 = 0.001 or 0.1% which improves the availability from 99% to 99.9% (8.76 hours per year) supply risk

At face value, the 2xline option performance (99.99% availability) looks similar to the line + generator option (99.9% availability).

However, in terms of “supply at risk annual hours” the performance numbers become:

- (0.0001x8760) = 0.876 hours for two lines and

- (0.001x8760) = 8.76 hours for the line plus generator.

In availability terms, the N-1 network option (two lines) could be represented as being only (99.99/99.9) = 1.001 times or 0.1% better than the generator supported network option.

In terms of hours (supply risk), the N-1 network option is (8.76/0.876) = 10 times or 1000% better than the generator plus line option.

The needed and acceptable reliability are therefore critical in determining the suitability of a possible supply option with the measure used likely to have a significant effect on how the alternatives may be perceived – eg: 99% availability represents a loss of supply time risk of 1% which is 87.6 hours (3 ½ days) per year. The former expression may give the impression of a satisfactory supply reliability which, if put the latter way may be seen to be unacceptable.

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