CENTRAL VICTORIAN greenhouse alliance

Rm 49 /1 Halford Street
Castlemeiane VIC 3450

Phone/Fax (03) 5472 5388
Mobile 0401 370 485

Email eo@cvga.org.au
ABN 71 2568 787 48

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Mr Chris Pattas
General Manager
Network Regulation South
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

email: aerinquiry@aer.gov.au cc: paul.dunn@aer.gov.au

Central Victorian Greenhouse Alliance

Submission to AER – 2011 Victorian electricity distribution price review

The Central Victoria Greenhouse Alliance (CVGA) welcomes the opportunity to comment on the AER's review of pricing for the Victorian Distribution Network Service Providers (DNSPs) for the period 2011-2016.

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission."

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Introduction

The Central Victorian Greenhouse Alliance, comprising 14 local governments, and businesses and community organisations, is playing a key role in creating sustainable, climate-aware communities and profitable, climate-friendly economies in our region.

Our objectives are:

- To reduce Central Victorian Greenhouse Gas Emissions by 30 per cent below 2000 levels with the goal of achieving zero net emissions by 2020, and
- To promote sustainable development and sustainable economic growth throughout the region.

Our key activities include:

- Raising awareness of climate change, its effects and the solutions;
- Initiating, driving and coordinating projects;
- Facilitating networks, partnerships and cooperative ventures;
- Sourcing project funding, information and resources; and
- Providing a forum for discussing opportunities and challenges.

Our region has:

- Enormous potential for generating and utilizing renewable energy and
- Committed and innovative communities, organisations and businesses.

The CVGA and its members are active proponents of many small distributed sustainable generation projects in regional Victoria, notably:

- Solar parks in Bendigo and Ballarat;
- Central Victoria Solar Cities project;
- Maine's Power project;
- A number of waste - to - bio energy projects, for both animal and crop waste;
- Stonefruit stone processing for energy generation.

It is important to note that the projects promoted by the CVGA could be characterised as “small business distributed sustainable generation projects”. That is, these are generally projects with relatively small output that generally would not require significant connection works or augmentation of the shared distribution network.

Context

CVGA members have a range of technically and economically viable small scale distributed sustainable generation projects ready to be deployed across regional Victoria. However, the consistent message from project proponents is that network connection forms the largest barrier to these projects coming to fruition.

In the context of the current price review process, the CVGA's focus relates to connecting distributed sustainable generation to the Victorian distribution networks.

The CVGA takes a positive view towards its task, recommending solutions rather than lamenting challenges. The CVGA also strives to work within the National Electricity Rules and the scope for regulatory discretion within the Rules.

Background

Historically, the electricity supply network has been constructed and managed with a vision of large generation facilities remote from population centres. In Victoria, the transmission and distribution networks have been designed to evacuate power from the large Latrobe valley generators, and transmit and distribute it to the rest of Victoria. The current structure of the networks demonstrates this vision.

This vision and the resulting structure of the networks was appropriate in its time, and the CVGA acknowledges the hard work and dedication exerted by the Victorian electricity supply industry to realise that vision.

However, the environment in which the Victorian electricity industry operates is changing, with a much greater societal focus on carbon emissions and environmental sustainability. This is clearly evident in the level of government policy initiatives resulting from the Garnaut Climate Change Review, the Carbon Pollution Reduction Scheme (CPRS) and Mandatory Renewable Energy Targets (MRET).

In recent years, there has been much activity on the subject of sustainable and distributed generation in the Australian electricity industry, including a large body of work undertaken by the Ministerial Council on Energy. While not an exhaustive list, this body of work includes:

- Code of Practice for Embedded Generation
- Charles River Associates Review of NEM Arrangements for Renewable and Distributed Generation - October 2006
- Impediments to the Uptake of Renewable and Distributed Energy, Discussion Paper, February 2006
- National and State Renewable Energy Initiatives, February 2006
- Impediments to the Uptake of Renewable and Distributed Energy, March 2006

- NERA Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation - April 2007
- NERA Demand Side Response and Distributed Generation Case Studies - April 2007
- NERA Network Planning and Connection Arrangements – National Framework for Distribution Networks – August 2007
- NERA Revised Demand Side Response and Distributed Generation Case Studies – August 2007
- AEMO, Minimising barriers to cost-effective small generator participation in the NEM: Discussion Paper
- AEMC, Review of Energy Market Frameworks in light of Climate Change Policies

This body of work exhibits a common thread – an acknowledgement that sustainable energy and embedded generation will become a larger and larger component of Australia's energy supply portfolio and that the management and regulation of distribution networks will need to evolve to accommodate that growth.

However, despite that good work, the experience on the ground is that it remains very difficult to obtain network connection for distributed sustainable generation projects.

To date, the National Electricity Rules are lagging behind this process, a function of the nature of the Rule Change process.

While work is progressing in this area, the CVGA sees an opportunity in this price review process to make allowances for the current changes to come to fruition. Failure to do this will mean that there will be limited scope for embedded generation to contribute to the operation of the electricity network in the current regulatory period – resulting in a further 5 year delay.

The CVGA's objective in this price review process is to find avenues, within the current National Electricity Rules, to enable connection of distributed sustainable generation projects.

The AER's Framework and Approach paper

In May 2009, the AER published its Framework and Approach[1] paper relating to this review in accordance with S6.8.1 of the Rules. In the Framework and Approach paper, the AER has outlined its likely approach to many aspects of the current review process,

[1] Framework and approach paper for Victorian electricity distribution regulation: CitiPower, Powercor, Jemena, SP AusNet and United Energy - Regulatory control period commencing 1 January 2011, May 2009

including the classification of services and the operation of various incentive mechanisms.

However, the CVGA notes that S6.8.1(h) the Rules provides that the proposed approach in the Framework and Approach paper is not binding on the AER or the relevant DNSPs:

> _6.8.1(h) Subject to clause 6.12.3, a framework and approach paper is not binding on the AER or a Distribution Network Service Provider._

In this submission, the CVGA will request the AER to revisit some of the proposed approaches it discussed in the Framework and Approach paper

Classification of services

One of the first of the Constituent Decisions the AER must make in a price review process relates to the classification of services under S6.12.1(1). The AER discussed its views on this matter in Section 2 of its Framework and Approach paper.

In its Framework and Approach paper, the AER proposed to classify connection and augmentation services as Negotiated Distribution Services in accordance with S6.2.1(a)(2) of the Rules.

The CVGA, on reviewing the form of regulation factors in section 2F of the National Electricity Law in light of the Victorian contestability framework, and the AER's reasoning, accepts that the direct costs associated with a customer connection should reasonably be classified as negotiated distribution services.

However, on reviewing the discussion in the Framework and Approach paper, it appears that the AER has not made a clear distinction between augmentation of DNSP assets that are directly related to the particular connection, and augmentation of the shared distribution network.

In its submission to this review, CitiPower made extensive commentary on this matter[2], noting that augmentation will form part of the distribution network and the services provided by augmentation assets will be 'shared distribution services' as defined in the Rules, and not a separate service.

> _Where a new customer connection requires an augmentation to the distribution network, the assets that are constructed as part of that augmentation will be used by CitiPower to provide distribution network services. This fact is recognised by the AER in the Framework and Approach Paper (on p.38) where it notes that the operation and maintenance of those assets will be treated as a Standard Control Service._
>
> _The assets associated with such an augmentation will form part of the_ 'distribution network' _as defined in the Rules and the service provided by means of those assets will be a_ 'shared distribution service' _as defined in the Rules. These augmentation works do not constitute the_

[2] See CitiPower Pty Regulatory Proposal: 2011 To 2015 30 November 2009, section 3.2.1.3

> *provision of a separate identifiable service that is to be classified by the AER. These works are instead an element of the provision of distribution network services.*

SP AusNet proposes to classify "above standard connection and augmentation works for new connections" as Standard Control Services.[3]

Particularly where distributed sustainable generation projects are deployed to assist the network in coping with network demands in excess of the capacity of the network, the CVGA is concerned that the cost of any augmentation of the shared network, that will ultimately be used to provide direct control services, would be charged to the distributed sustainable generation project. This would create a major barrier to distributed sustainable generation projects.

As noted in the CRA report to DITR on NEM Arrangements for Renewable and Distributed Generation [4]

> *it is more often the case that the distribution network will not require augmentation as a Prescribed Service at the same time as an embedded generator is commissioned. There are two reasons for this: embedded generation is more likely to decrease loading on a network and thus defer the need for augmentation of a Prescribed Service within distribution or transmission networks, and the generally smaller scale of embedded generation does not affect as great an area of the network as larger generators.*

The CVGA notes that adding embedded generation to a feeder is likely to be able to defer augmentation of the shared network. It seems incongruous, therefore, that the costs of augmenting the shared network should be fully charged against the very projects that are striving to avoid or defer the augmentation of the network.

Consistency in the form of regulation

One of the factors to which the AER must have regard in classifying a distribution service is

> *6.2.1(c)(3) the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction);*

The CVGA notes an inconsistency in the form of regulation for generator connection to distribution network when compared to transmission networks. As noted in the CRA report to DITR on NEM Arrangements for Renewable and Distributed Generation:[5]

> *Network charges are potentially the most contentious and significant issue in this review. Many submissions noted concern about the principles for determining amounts charged to small generators where the network needs to be augmented upstream of the local point of connection. Currently, embedded generators often face charges for such augmentations.*

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[3] SP AusNet regulatory proposal p36.

[4] Charles River Associates, *Review of NEM Arrangements for Renewable and Distributed Generation*, Prepared For Department of Industry, Tourism and Resources (DITR) October 2006

[5] Charles River Associates, October 2006

> _… the terms "shallow" and "deep" connection generally refer to whether a generator is required to pay any part of the cost of the shared network as a matter of policy. Under a "shallow" connection cost regime generators pay no part of the cost of the shared network and customers therefore pay it all. Under a "deep" connection regime, some of the cost is apportioned to generators with the remainder being paid by customers. In August 2006 the AEMC published a draft rule which confirmed the current "shallow" connection arrangement for generators connected at transmission level. Within the NEM arrangements this is achieved by not charging generators for Prescribed Services._

There does not appear to be a clear policy reason for the different treatment of "deep" connection costs (any costs associated with augmenting the shared network) between transmission and distribution networks.

In the interests of consistency in the form of regulation for similar services between transmission and distribution connected generation, the CVGA submits that augmentation of the upstream network should not be classified as a negotiated distribution service, but rather be classified as a direct control service.

Recommendation

The CVGA requests the AER to revisit its proposed approach on the classification of connection and augmentation services to classify augmentation of the shared distribution network as a direct control service under S6.2.1(a)(1) of the Rules.

Scope for distributed sustainable generation in the current price review

On review of the DNSPs' regulatory proposals, the CVGA finds that there are significant opportunities for embedded generation to contribute to the operation of the distribution networks and defer network investment over the current regulatory period, particularly in regional Victoria.

By way of example, SP AusNet, in its regulatory proposal, relies on DM and embedded generation projects arising over the course of the current regulatory period:[6]

> _Demand side management initiatives are not expected to significantly reduce network peak demands within the forthcoming regulatory control period. However, at the margin, particularly on the rural network, several non-network initiatives are expected to allow capex to be deferred._

The SP AusNet regulatory proposal discusses Distributed Generation at Euroa and Generation support, embedded generation or voluntary load curtailment in order to defer feeders at five identified sites. It appears from the text that the particular projects required to achieve this feeder deferral have not been identified.

The CVGA considers that this type of information presents opportunities for project proponent to investigate opportunities to defer the capital expenditure as identified.

[6] SP AusNet regulatory proposal S6.3 p112.

For this submission, the CVGA has commissioned a high level analysis of the load and capacity of a number of substations in the Powercor service territory. The purpose of this analysis was to investigate opportunities for distributed sustainable generation to reduce loads on substations, with an aim to deferring capital expenditure or customer reliability.

The Powercor territory has been chosen simply because it is the CVGA's "home ground". Time permitting, and consistent with its focus on rural and regional Victoria, the CVGA may undertake similar analyses on selected substations in the SP AusNet service territory. [7]

This analysis was undertaken based on the supporting information filed by Powercor with its regulatory proposal, notably Powercor's Distribution System Planning Report 2008, and spreadsheets *Zsub Utilisation V4* and *22kV Feeder Utilisation V4.*

Findings

The high level engineering study reviewed capacity and load forecasts at four substations and their related feeders: Castlemaine, Bendigo, Eaglehawk and Ballarat, and the Bendigo transmission terminal station (BETS). These studies are summarised in the appendix to this submission.

The study found that, in all the distribution substations examined, there was significant scope to connect distributed sustainable generation. In the cases of Castlemaine, Bendigo and Eaglehawk, there would therefore appear to be significant scope in the short term for embedded generation to reduce the magnitude and risk of loss of load, in the event of a network contingency.

Moreover, in the case of Castlemaine[8] and Eaglehawk, connection of distributed sustainable generation would also potentially defer the planned transformer augmentation.

In the case of the related feeders, in Castlemaine, there appears also to be ample scope for medium sized embedded generator connection (1-5 MW) to the trunk 22 kV feeders. For Bendigo, Ballarat and Eaglehawk, there appears to be considerable scope for small scale (1-5 MW) distributed sustainable generation connections to the trunk 22

[7] In conducting this analysis, the CVGA found some inconsistencies in the information provided by Powercor. It is likely that these differences are simply the result of different engineering analyses being conducted at different times, and for the most part the differences are not significant.
However, the CVGA notes that the Distribution System Planning Report (DSPR) filed as an attachment to the Powercor regulatory proposal is dated December 2008, almost a full year before the regulatory proposal was filed. However, the CVGA's engineering advisor was able to source the more recent December 2009 version from the Powercor website.
Some differences came to our attention in the process or conducting the engineering review, notably the plans to upgrade the Castlemaine and Bendigo substations, which did not feature in the 2008 DSPR filed with Powercor's Regulatory Proposal.
It is not clear which version of the DSPR is "on the record" for the purposes of the AER's analysis.

[8] The proposed date of augmentation of the Castlemaine substation has changed form 2016 in the December 2008 DSPR to 2010 in the December 2009 DSPR.

kV feeders at this location. The generation would act to offset the relatively heavy feeder utilisation and could thereby potentially improve customer reliability.

The CVGA's analysis is filed as an appendix to this submission.

Incentive mechanisms

In its Framework and Approach paper, the AER discusses the application of several incentive mechanisms as required under S6.8.1(b)(2)-(4) of the Rules. Of particular interest to the CVGA is the Demand Management Incentive Scheme (DMIS) as described in S6.6.3 of the Rules. The AER published a separate paper on the operation of the DMIS in April 2009.[9]

Under the Rules, the goal of the DMIS is:

> *6.6.3(a) …to provide incentives for* Distribution Network Service Providers *to implement efficient non-network alternatives or to manage the expected demand for* standard control services *in some other way.*

Throughout this process, the CVGA has remained conscious of the DNSPs' economic drivers as embodied in the regulatory framework. In particular, the CVGA is mindful that the DNSPs earn returns primary through the construction and ownership of energy distribution assets.

In many ways, the connection of a distributed sustainable generation facility whose purpose is to defer or avoid the construction of network augmentation assets runs contrary to the DNSPs' primary economic drivers.

Under S6.6.3(b)(2) of the Rules:

> *(b) In developing and implementing a* demand management incentive scheme*, the* AER *must have regard to:*
>
> *(2) the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a* Distribution Network Service Provider's *incentives to adopt or implement efficient non-network alternatives;*

The CVGA submits that, under the Building Block structure of the Rules, a DNSP has a strong disincentive to engage in any activity, particularly implementing efficient non-network alternatives, that would serve to defer or reduce its income-earning investment in the network.

The Demand Management Innovation Allowance

In the AER's paper on the DMIS, it comments on the purpose of the DMIS:

[9] AER, Demand Management Incentive Scheme - Jemena, CitiPower, Powercor, SP AusNet and United Energy, 2011–15. April 2009

> *The AER's DMIS for Victorian DNSPs is designed to complement the broader regulatory framework in providing incentives for DNSPs to carry out non-network alternatives, and encourage DNSPs to explore alternate approaches to managing expected demand for standard control services.*
>
> *The DMIS is designed to supplement a DNSP's approved capital and operating expenditure, to facilitate investigation and implementation of demand management strategies. The development of reliable and viable strategies will allow DNSPs to implement non-network alternatives where efficient, and to manage the expected demand for standard control services by means other than network augmentation.*

The CVGA submits that expenditure targeted to connect distributed sustainable generation projects to the network, with an aim to defer network augmentation, fits squarely within the ambit of the DMIS.

However, the CVGA notes that the AER has identified two separate components of the DMIS – a Demand Management Innovation Allowance (Part A) and a recovery of foregone revenue mechanism (Part B).

The CVGA agrees with the AER's findings that it is necessary to compensate the DNSP for revenue lost due to implementing a DM project. Such a loss may occur where embedded generation is co-located with a load, which takes a proportion of the generator's output. In this case, less electricity flows through the customer meter, and the DNSP has a lower basis on which to charge for its services.

However, the CVGA notes that a "pure play" embedded generation project, which exports its power directly to the distribution network, causes no such loss of revenue to the DNSP; the embedded generation project does not influence the amount of consumption at load points. The CVGA therefore notes that the operation of the DMIS is restricted to the benefits the DNSP may obtain through the Part A DMIA.

Connecting embedded generation under the DMIA

The CVGA's experience has been that the processes for connecting embedded generation to the distribution network have been cumbersome and ad hoc in nature. The CVGA submits that there is benefit in developing greater expertise in connecting embedded generation projects. Further, the CVGA submits that the development of this expertise fits well within the objectives of the DMIA.

The AER also suggests that expenditure of a capital nature can be included in the DMIS:[10]

> *Allowing capex under the DMIA through the DMIS criteria allows cost recovery of innovative and potentially untested demand management capex projects and programs. Through the DMIA, the DMIS offers a mechanism to recover such capex, without necessary recourse to the capex criteria in clause 6.5.7 of the NER.*

[10] AER Framework and Approach paper p121

The CVGA notes that the AEMC in its *Review of Energy Market Frameworks in Light of Climate Change Policies*, suggested the extension of the DMIA to include the connection of embedded generation:[11]

> *We consider that the existing DMIA should be expanded so that it also includes consideration for connecting embedded generators. The purpose of the expansion would be to encourage distribution businesses to consider more innovative and cost effective ways of connecting generators to distribution networks. Given the DMIA is also being considered as part of the Review of Demand-Side Participation in the NEM, we propose developing a draft Rule for this change in conjunction with other recommendations that may result from that review.*

This AEMC recommendation was accepted by the MCE:[12]

> *Consequently, the MCE supports the AEMC's proposal for expanding the DMIA to incorporate the connection of embedded generators in recognition of the role this is likely to play in distribution network operation in the future.*

The CVGA notes that the DMIS has very broad scope for discretion at this stage of the process. The CVGA submits that the AER could expand the current DMIS to adopt this recommendation within its existing discretions.[13]

> *The AER's final decision on how the DMIS is to apply to a DNSP in a regulatory control period will be part of the distribution determination it makes for that DNSP.*

Recommendation

The CVGA requests the AER to modify its DMIS to specifically include consideration for connecting embedded generators.

Indicative assessment under the DMIS

In its Framework and Approach paper, the AER included scope for an indicative up-front assessment as to whether proposed DM initiatives would qualify under the DMIS:[14]

> *In response to stakeholder submissions, the AER, in its final DMIS for Victorian DNSPs, has also included an optional, up-front, indicative approval process as part of the DMIA. Under this process, the AER will examine proposed demand management initiatives (under the DMIS) and provide an indicative assessment of whether or not these projects or programs satisfy the DMIA assessment criteria.*

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[11] AEMC, Review of Energy Market Frameworks in light of Climate Change Policies p122.

[12] Review of Energy Market Frameworks in light of Climate Change Policies, Response to Australian Energy Market Commission's Final Report, MCE, December 2009, p13.

[13] AER, *Demand Management Incentive Scheme - Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, April 2009

[14] AER Framework and Approach paper, p120

The CVGA requests the AER to broaden the scope of this option by allowing the project proponent to request the AER to conduct the up-front indicative approval process. The CVGA acknowledges that the project proponent will not have all the necessary detailed costing information to conduct a detailed analysis. However, based on the CVGA's review of the DNSPs' Distribution Network Planning Reports, the proponent should be able to indicate the general extent of connection works required to undertaken. By way of demonstration, analysis of four Powercor substations, based on information filed with the regulatory proposal, are attached as an appendix to this submission.

The CVGA submits that, if a project proponent's approach to the DNSP to seek connection of a distributed sustainable generation project includes the AER's indicative approval for the costs to be included in the DMIA, the scope for the connection proceeding are greatly improved.

Recommendation

The CVGA requests the AER to broaden the scope of the up-front indicative assessment under the DMIS to allow project proponents to request the AER to conduct the up-front indicative approval process.

The quantum of the DMIA

The CVGA submits that it is evident that the allowance of $3 million proposed by the AER for the DMIA (for each of Powercor and SP AusNet) is so low as to be well out of step with community and stakeholder expectations. The CVGA considers that this level of funding will be inadequate to allow the continued research and development of a range of projects, including the connection of distributed sustainable generation.

The CVGA proposes that an incentive allowance in the order of 0.5% of the annual revenue requirement is more appropriate. This would be in line with the level of funding permitted by Ofgem under the Innovation Funding Incentive (IFI) regime, which it has applied to electricity distributors in the United Kingdom.[15] The IFI scheme has now been extended to March 2015.[16]

An allowance of 0.5% of Powercor and SP AusNet's revenue requirement would equate to a DMIA allowance of about $2.5 million per year over the regulatory control period The CVGA considers that an allowance in this order of magnitude would enable the DNSPs to make considerable progress in connecting distributed sustainable generation projects to the network.

As a further matter, the CVGA would like to see a proportion of this funding "earmarked" for the connection of distributed sustainable generation projects. While the CVGA is confident that connection of distributed sustainable generation projects will deliver excellent value from this fund, it is concerned that the DNSPs may not be incentivised

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[15] See for example Ofgem's summary: Reports by Distribution Network Operators (DNOs) on Innovation Funding Incentive (IFI) and Registered Power Zone (RPZ) activity for 2007-2008.

[16] Open Letter Consultation on the Innovation Funding Incentive and Registered Power Zone Schemes for Distribution Network Operators, Ofgem, 14th February 2007.

to adequately explore this option. This would potentially defer network augmentation investment, improve reliability of supply, and diversify the electricity supply portfolio.

Recommendation

The CVGA recommends an increase in the level of the DMIA in the order of 0.5% of annual revenue, and that a proportion of this funding be earmarked to connection of distributed sustainable generation projects.

Summary

The CVGA thanks the AER for the opportunity to comment on the DNSPs' regulatory proposal in the price review process.

The CVGA requests the AER to take the following action:

- acknowledge the scope that embedded generation has to contribute to the management of the network and the deferral of capital expenditure in the current regulatory period;
- revisit its proposed approach on the classification of connection and augmentation services to classify augmentation of the shared distribution network as a direct control service under S6.2.1(a)(1) of the Rules.
- modify its DMIS to specifically include consideration for connecting embedded generators;
- broaden the scope of the up-front indicative assessment under the DMIS to allow project proponents to request the AER to conduct the up-front indicative approval process; and
- increase the level of the DMIA in the order of 0.5% of annual revenue, and that a proportion of this funding be earmarked to connection of distributed sustainable generation projects.

Appendix: Embedded generator opportunities in Powercor territory

The following observations are made concerning opportunities for embedded generation to defer or otherwise influence network augmentation in regions served by selected substations and feeders in the Powercor territory.

The Powercor territory has been chosen simply because it is the CVGA's "home territory". Time permitting, and consistent with its focus on rural and regional Victoria, the CVGA may undertake similar analyses on selected substations in the SP AusNet service territory.

It should be noted that the forecast contained in the spreadsheet from which substation utilisations are derived[17], differs in detail from that in the Distribution System Planning Report[18]. It is likely simply that this may arise from the forecasts being prepared at different times.

[17] Excel file Zsub utilisation V4.XLS, 15 February 2010.

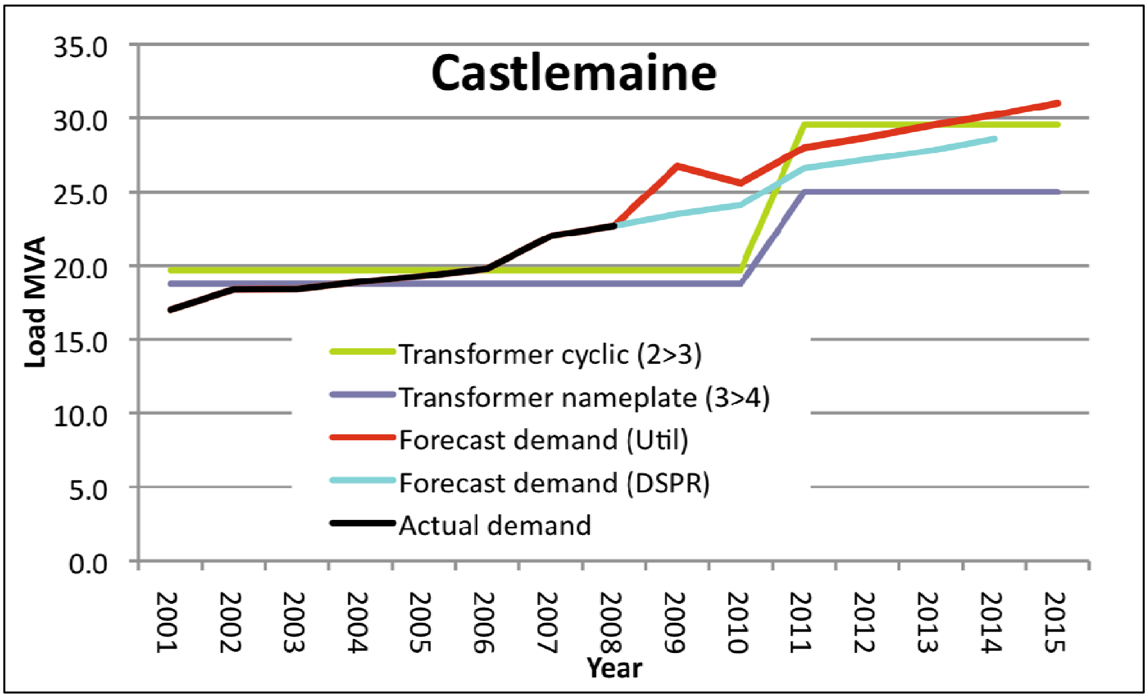
[18] Distribution System Planning Report, Powercor Australia Limited, December 2009.

Castlemaine 66/22 kV zone substation and 22 kV feeders

The Castlemaine area is serviced by a relatively small 66/22 kV substation, which is relatively heavily loaded. The substation has three transformers and its configuration is such that the failure of a transformer would cause complete loss of supply and require manual switching to enable restoration.

In the event of transformer failure, Powercor plan to transfer load to adjacent substations using the available capacity of the 22 kV system. Since the 2008 Planning Report[19], Powercor have made significant changes in some planning assumptions and now plan to install a fourth transformer at the substation in 2010.

The relevant capacity, actual and forecast system loading from the most recent Planning Report are illustrated in the chart below.



Based on Powercor's assessment of the firm (N-1) capacity of the substation, the substation load exceeds this by 22-37% in 2010. However, there is doubt concerning the validity of Powercor's firm capacity rating.

The firm summer cyclic (overload) rating for two transformers (ie. with one out of service) is claimed by Powercor to be 15.7 MVA[20]. This is a loading of 126% of nameplate and seems unusually high. A transformer summer cyclic rating of 115% to possibly 120% of nameplate would normally be assigned. Loading a transformer to such a high level would cause overheating and rapid insulation degradation.

[19] Distribution System Planning Report, Powercor Australia Limited, December 2008.

[20] Distribution System Planning Report, 2009, p. 23.

Based on a more realistic cyclic rating of 15 MVA (120% of nameplate), the 2010 summer load would exceed the firm capacity of the substation by 60-70%.

By way of comparison, it should be noted that the NSW licence conditions would ordinarily provide for the augmentation of such a substation to maintain the (N-1) standard of supply security.

The annual hours at risk is stated as growing from 277 in 2010, to 2,514 in 2013[21]. This is the number of hours for which the demand exceeds the (N-1) capacity of 15.7 MVA, and in the final year equates 28% of hours. However, if a firm transformer capacity of 15 MVA is substituted, the forecast summer load of 28.6 MVA in 2010 would exceed the firm capacity by close to 90% and the number of hours at risk would be significantly higher than the stated figure.

The load forecasts do appear to contain a noticeable step increase in 2011, which may be attributable to the proposed bacon processing plant.

Powercor now is planning to augment the transformer capacity at this location with an additional transformer, in 2010.

There are five 22 kV feeders sourced at Castlemaine substation, identified as CMN001 to CMN005. The first four of these are classified as “Rural Long” and the last as “Urban”.

The rural feeder capacities and 2009 loading and utilisation are set out in the table below[22]. Although not stated in the source document, it should be noted the capacity levels would apply to the three phase “trunk” main connections and not to the spur lines or SWER connections to those trunks.

22 kV Feeder	**CMN001**	**CMN002**	**CMN003**	**CMN004**	**CMN005**
Classification	Rural Long				Urban
Capacity MVA	10.16	7.37	10.16	7.37	12.95
Loading MVA	5.65	3.00	8.17	4.06	8.13
Utilisation %	59%	44%	80%	55%	63%

There would appear to be adequate capacity to accommodate the connection of medium scale (1-5 MVA) embedded generation on all trunk 22 kV feeders. Generation levels in the order of the connected load and up to the feeder capacity could be potentially accommodated, subject to the resolution of any technical requirements.

21 Distribution System Planning Report, 2009, p. 36.

22 Excel file Powercor 22 kV feeder utilisation V4.XLS, 15 February 2010.

Castlemaine zone substation summary

The Powercor analysis of load at risk at this location appears likely to be understated because of the assumption of a higher than appropriate cyclic overloading level for transformers.

The substation is currently loaded beyond its firm (N-1) rating and the extent of this situation also appears to be understated. Powercor's forecast loading exceeds a firm summer rating of 15 MVA (120% of nameplate) by 61 to 71% in 2010.

There would therefore appear to be significant scope in the short term for embedded generation at this location to reduce the magnitude and risk of loss of load, in the event of a network contingency.

The generation would also potentially defer the planned transformer augmentation. However, as Powercor are planning to add the fourth transformer in 2010, a deferral option would be needed immediately.

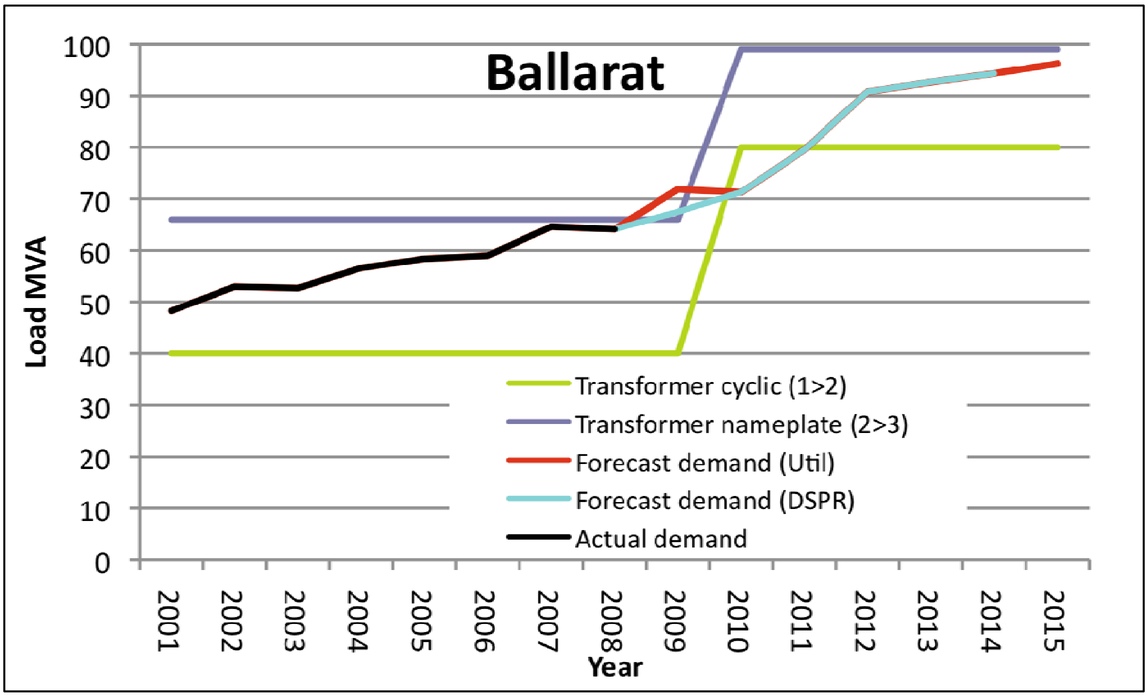
There appears also to be ample scope for medium sized embedded generator connection (1-5 MW) to the trunk 22 kV feeders at this location.

Ballarat South 66/22 kV zone substation and 22 kV feeders

Ballarat South substation supplies Ballarat and environs and now has three, 33 MVA transformers. As with Castlemaine, the configuration of the substation would lead to complete loss of supply on the failure of a transformer, with manual restoration of supply.

In the event of a transformer failure, there is currently adequate capacity at this location, following the installation of an additional transformer in 2010[23].

The relevant information is charted below.



The summer cyclic rating of the Ballarat transformers is approximately 115% of the nameplate capacity, which is at within a feasible range.

Powercor does not quote loss of load statistics for this location in the Planning Report.

There are nine, 22 kV feeders sourced at Ballarat substation. Of these, four are classified Urban, two Rural Short and three Rural Long. The feeders, their classification, loading and utilisation are set out in the table below.

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23 Distribution System Planning Report, 2009, p. 22.

22 kV Feeder BAS	012, 013, 014, 024	023, 034	011, 021, 022
Classification	Urban	Rural short	Rural Long
Capacity MVA	7.1 - 9.1	6.7 - 9.1	6.7 - 9.1
Loading MVA	5.0 - 10.1	5.6 - 7.6	7.0 - 12.2
Utilisation %	61 - 111%	83 - 84%	111 -181%

Many of the feeders are loaded to relatively heavy utilisation levels of more than 80%. By way of comparison, it should be noted that a level of utilisation of 80% is generally applied to High Voltage feeder utilisation in metropolitan areas by the NSW licence conditions, to ensure reasonable reserve capacity to restore customer supply in the event of a network contingency.

Ballarat South zone substation summary

Following the installation of a third transformer, there would appear to be no scope for embedded generation at this location to reduce the magnitude and risk of loss of load, in the event of a network contingency.

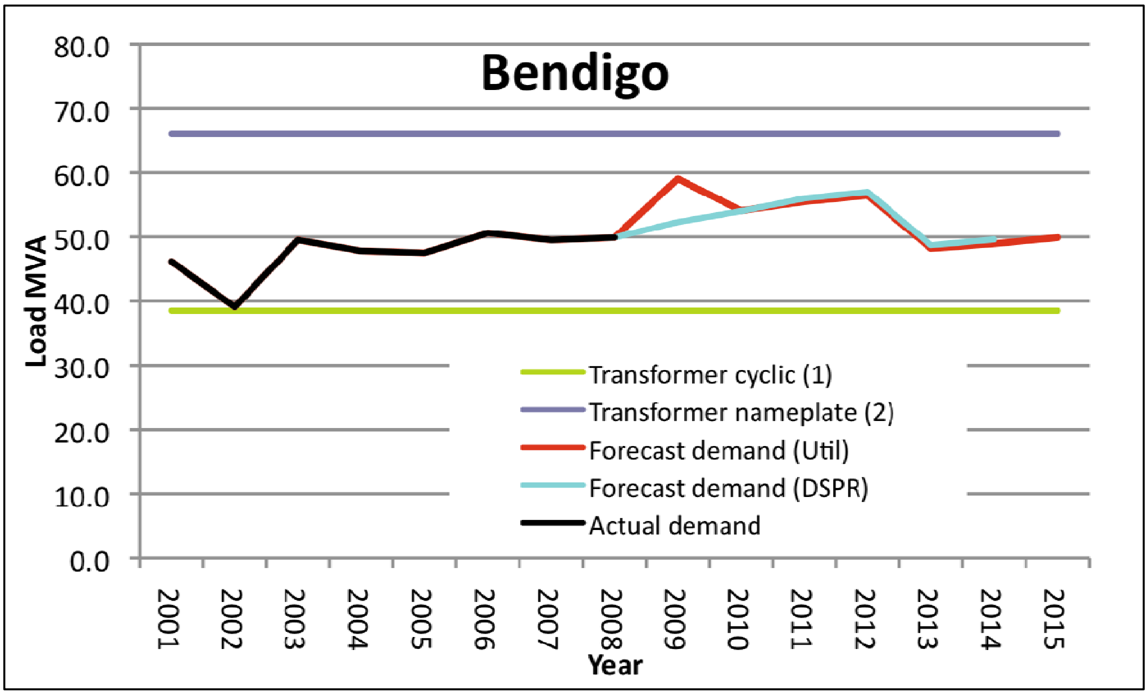
There does appear to be considerable scope for small scale (1-5 MW) generator connections to the trunk 22 kV feeders at this location. The generation would act to offset the relatively heavy feeder utilisation and could thereby potentially improve customer reliability.

Bendigo 66/22 kV zone substation and 22 kV feeders

Bendigo substation supplies the city and environs and has two, 33 MVA transformers. The configuration of the substation permits restoration of supply by remote switching.

In the event of a transformer failure, Powercor plan to transfer load to adjacent substations using the available capacity of the 22 kV system, and augment the system with an additional 22 kV feeder in 2010[24].

Bendigo substation is currently loaded above Powercor's firm capacity for the substation. The relevant information is charted below.



The summer cyclic rating of the Bendigo transformers is approximately 117% of the nameplate capacity. This level of emergency loading seems appropriate.

The substation is currently loaded well beyond its firm rating (with one of the two transformers out of service). The forecast 2010 load is 137% of the firm capacity. The forecast would exceed the firm rating in 2012 by around 143%, beyond which it appears some load would be transferred to an adjacent location.

Powercor quotes the annual hours at risk and the annual energy at risk for this location[25]. The hours at risk vary from 146 to 207, with the annual energy at risk escalating from 750 to 1460 MWh.

24 Distribution System Planning Report, 2009, p. 22.
25 Distribution System Planning Report, 2009, p. 29.

The capacity of the seven 22 kV feeders at Bendigo, the 2009 loading and utilisation are summarised in the table below[26]. Again, it should be noted the capacity levels would apply to the "trunk" main connections.

22 kV Feeder BGO	**011, 012, 022, 024**	**013**	**021, 023**
Classification	Urban	Rural short	Rural Long
Capacity MVA	10.7 - 14.6	14.6	10.7 - 13.3
Loading MVA	6.0 - 12.4	13.3	8.0 - 11.3
Utilisation %	42 - 85%	91%	60 -105%

A number of the feeders are relatively heavily loaded and there would appear to be adequate capacity to accommodate the connection of medium scale embedded generators on all trunk 22 kV feeders. Generation levels in the order of the connected load and up to the feeder capacity could be potentially accommodated, subject to the resolution of any technical requirements. A number of feeders are relatively heavily loaded and embedded generation offers the potential of improving customer reliability.

Bendigo zone substation summary

The substation is currently loaded significantly beyond its firm (N-1) rating and the extent of this situation is increasing. Powercor's forecast loading exceeds a firm summer rating by 37% in 2010.

There would therefore appear to be significant scope for embedded generation at this location to reduce the magnitude and risk of loss of load, in the event of a network contingency.

There does not appear to be scope for an embedded generation project at this location to defer major transformer augmentation.

There appears also to be considerable scope for medium scale generator connections to the trunk 22 kV feeders at this location. The generation would act to offset the relatively heavy feeder utilisation and could thereby potentially improve customer reliability.

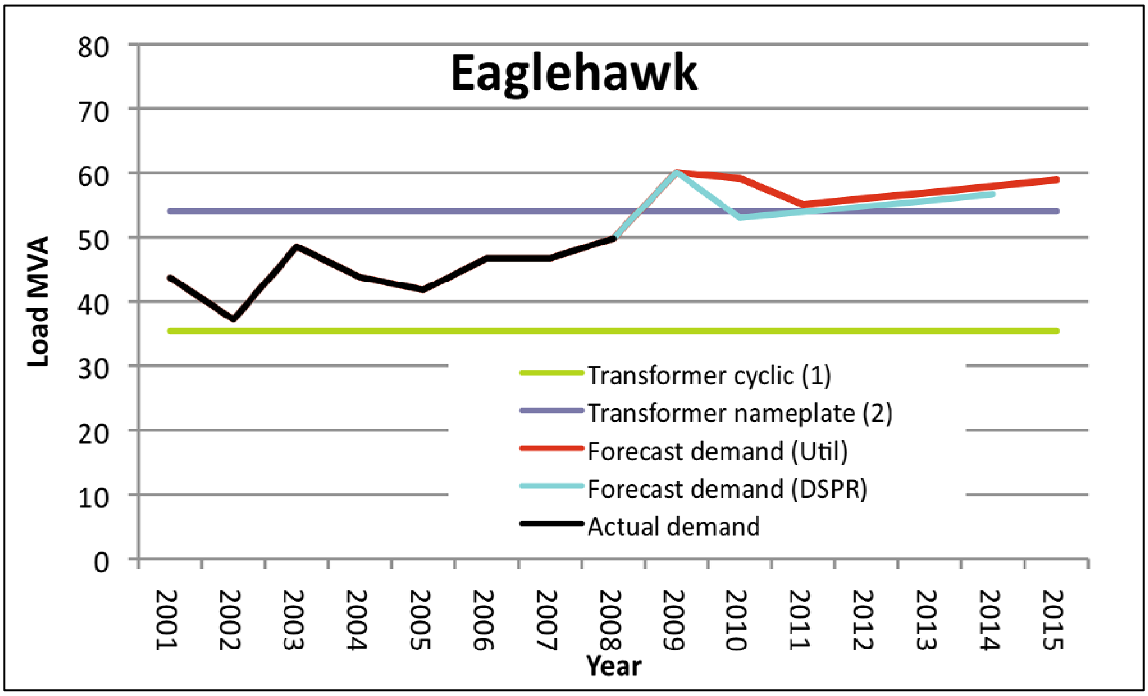
26 Excel file Powercor 22 kV feeder utilisation V4.XLS, 15 February 2010.

Eaglehawk 66/22 kV zone substation and 22 kV feeders

Eaglehawk substation supplies the town and environs and has two, 27 MVA transformers. The configuration of the substation permits restoration of supply by remote switching.

In the event of a transformer failure, Powercor plan to transfer load to adjacent substations using the available capacity of the 22 kV system, and augment the system with an additional 66/22 kV transformer by 2012 or later[27].

Eaglehawk substation is also currently loaded well above Powercor's firm capacity for the substation. The relevant information is charted below.



Based on Powercor's assessment of the firm (N-1) capacity of the substation of 35.4 MVA, the substation load would exceed this by 50% in 2010. However, as with Castlemaine, there is doubt concerning the validity of Powercor's firm capacity rating. A cyclic rating of approximately 130% of the transformer nameplate rating has been assigned by Powercor. A more reasonable assumption of 120% of the nameplate rating would yield a firm capacity of 32.4 MVA, which the load would exceed by 64%.

Powercor quotes the annual hours at risk and the annual energy at risk for this location[28]. The hours at risk vary from 365 to 432, or 5% of hours. The annual energy at risk escalates from 2116 to 3315 MWh.

27 Distribution System Planning Report, 2009, p. 41.

28 Distribution System Planning Report, 2009, p. 29.

The capacity of the eight 22 kV feeders at Eaglehawk, their 2009 loading and utilisation are summarised in the table below[29]. Capacity levels would apply to the "trunk" main connections.

22 kV Feeder EHK	**021, 022, 034**	**031, 032, 033**	**023, 024**
Classification	Urban	Rural short	Rural Long
Capacity MVA	12.9 - 17.3	12.9 - 13.3	12.9
Loading MVA	4.5 - 7.1	8.1 - 11.4	8.3 - 11.7
Utilisation %	26 - 54%	63 - 88%	72 - 90%

A number of the feeders are relatively heavily loaded and there would appear to be adequate capacity to accommodate the connection of medium scale embedded generators on all trunk 22 kV feeders. Generation levels in the order of the connected load and up to the feeder capacity could be potentially accommodated, subject to the resolution of any technical requirements. On feeders that are relatively heavily loaded, embedded generation offers the potential of improving customer reliability.

Eaglehawk zone substation summary

The substation is currently loaded significantly beyond its firm (N-1) rating and the extent of this situation is increasing.

There would therefore appear to be significant scope for embedded generation at this location to reduce the magnitude and risk of loss of load, in the event of a network contingency.

There appears to be scope for an embedded generation project at this location to defer major transformer augmentation, planned for 2012 or later.

There appears also to be scope for medium scale generator connections to the trunk 22 kV feeders at this location. The generation would act to offset relatively heavy utilisation on some feeders and could thereby potentially improve customer reliability.

[29] Excel file Powercor 22 kV feeder utilisation V4.XLS, 15 February 2010.

Transmission connection works

The above zone substations are in a portion of the Powercor territory that is serviced by a 66 kV system emanating from two 220/66 kV terminal substations on PowerNet's transmission system, at Ballarat and Bendigo.

In the Victorian jurisdiction, the DNSP has responsibility for planning the connection assets to the transmission system. At one of these terminal stations, Bendigo (BETS), Powercor is planning to augment the transmission connection capacity[30].

The 66 kV system emanating from Bendigo services Bendigo and Castlemaine 66/22 kV zone substations and adjacent areas and recorded a summer peak demand of 256 MVA in 2009 and has growing at a rate of 7.5%, or around 19 MVA per year.

In the Application Notice, Powercor describes options for the reinforcement of the existing transformer capacity of 265 MVA at Bendigo and sets out a preferred Option 3:

Leave all existing BETS transformers in service and:

install two new 75 MVA 220/22 kV transformers in parallel with the existing transformers; then

replace the existing single phase transformer groups with a single 150 MVA 220/66 kV transformer during SPI.

The commissioning of the first stage of these works is planned for 2012.

Bendigo Terminal Station summary

The terminal substation is proposed to be augmented in 2012 by the addition of transformer capacity.

The growth of load in this substantial load area would require the provision of embedded generation having a firm capacity in summer in the order of 20 MVA in order to enable deferral of the proposed works.

The timing of this proposed augmentation would require the urgent development of such a generation alternative.

Harry Colebourn

16 February 2010

30 Powercor, Application Notice - Proposed Augmentation of Bendigo Terminal Station, June 2009.