ELECTRICITY TRANSMISSION NETWORK

PLANNING CRITERIA

July 2003

Victorian Energy Networks Corporation
Melbourne, Victoria

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1 Introduction

VENCorp is the Transmission Network Service Provider for the shared transmission network in Victoria under the National Electricity Code (NEC) and as such has entered into an access undertaking with the ACCC regarding provision of access to the transmission network. VENCorp undertakes its responsibility in accordance with Victorian legislation, Licence obligations, the National Electricity Code and the Victorian Electricity System Code and it assesses the feasibility of transmission projects as detailed in this electricity transmission network planning criteria.

VENCorp's transmission network planning is aimed at ensuring that, following the loss of the most critical transmission element, including at times of peak demand,

- the security of the power system can be maintained;
- transmission plant ratings are not exceeded; and
- the network performance requirements in Schedule 5.1 of the National Electricity Code are met.

To satisfy these requirements, VENCorp accepts possibility of load shedding after an event but includes the expected unserved energy in the cost-benefit analysis, which is used to determine the optimum solution and implementation timing for an augmentation. This involves investment decisions based on a probabilistic analysis of energy at risk, which includes consideration of the probability-weighted impacts on supply reliability of unlikely, high cost events such as single and multiple outages of transmission elements, generation or rotating reactive compensation plant, and unexpectedly high levels of demand. This approach provides a sound actuarial estimate of the expected value of energy at risk. However, implicit in its use is acceptance of the risk that there may be circumstances when the planned capability of the network will be insufficient to meet actual demand.

As well as planning for loss of single element events, VENCorp considers loss of multiple elements as part of the planning process and determines what emergency and control schemes should be provided to minimise the disruption that such events could cause.

VENCorp commenced detailed consultation on its electricity transmission planning criteria in February 2001 and published a final report[1] on 23 May 2003. In light of respondents' submissions to VENCorp's consultation papers, and having regard to the analysis set out in the final report, VENCorp adopted the following policy in relation to its electricity transmission planning criteria:

1. VENCorp will continue to:
    - apply an approach that is consistent with the requirements of the ACCC's "net market benefits test" in the economic evaluation of transmission network investment decisions; and

[1] "Response to Submission: Final Report, The value of unserved energy to be used by VENCorp for Electricity Transmission Planning" see VENCorp web site www.vencorp.com.au

- apply a probabilistic approach, where practicable, except in those cases where VENCorp is required to meet a performance standard under Schedule 5.1 of the Code (At this stage the only non-discretionary projects identified in Schedule 5.1 that would not be the subject of a probabilistic assessment would be the requirements under S5.1.9 - Fault clearance times, S5.1.10 - Load shedding facilities and S5.1.14 -Remote monitoring equipment, which are all secondary equipment projects).

2. VENCorp will to adhere to its present policy of not including externalities in the economic evaluation of transmission investment decisions, but provide information on externalities associated with its decisions, so that Government, market participants and other stakeholders may be informed of such issues, where these may have a bearing on the investment decision;

3. In its transmission investment evaluation decisions, VENCorp will use a Value of Customer Reliability (VCR) of $29,600 to value unsupplied energy.

4. A sector specific VCR may be applied where transmission constraints affect essentially only a reasonably clearly distinguishable subset of Victorian load. Table 1 details sector specific values. Individual terminal station loading data will be used to identify subsets of the Victorian load for individual projects.

SECTOR	**VENCorp Study (2002)**
	VCR($/MWh)
Residential	$11,867
Commercial	$56,625
Agricultural	$54,782
Industrial	$18,531
VCR_{State} (TOTAL)	**$29,600**

Table 1 - VCR for different sectors

5 VENCorp will adhere to its present policy of detailed consultation on a project-by-project basis.

Whilst VENCorp will plan and develop the Victorian transmission network in line with this policy, it will also develop the network outside this policy to meet the legitimate electricity transmission needs of parties fully funding such developments, as the NEC also allows.

2 Economic Planning Basis

All regulated transmission investment decisions must satisfy the regulatory test as promulgated by the ACCC[2]. The key economic test involves deciding whether an investment maximises the net present value of the market benefit, which is the total net benefit to all those that produce, distribute and consume electricity in the National Electricity Market. This section outlines some of the key components in undertaking economic investment planning.

2.1 Probabilistic Planning

VENCorp applies a probabilistic planning approach to evaluate the risks associated with transmission constraints, where practicable, except in those cases where VENCorp is required to meet a performance standard under Schedule 5.1 of the Code. The probabilistic approach takes into account the fact that the level of supply reliability is uncertain because there are variations in both supply and demand as:

- demand varies due to factors such as forecasting inaccuracies and economic and weather impacts; and

2 A summary of the regulatory test is provided in Appendix 1

- supply varies due to factors such as variability in the performance and availability of generating plant (and, to a much lesser extent, variability in the capacity and availability of transmission plant).

A market simulation model is used to determine the hourly generation dispatch for a large number of scenarios to capture the range of variations of these key parameters. Critical transmission plant loadings are then determined on an hour by hour basis and compared with the network capability ratings. This allows the risks associated with the transmission system to be identified.

A range of statistics is then used to build a comprehensive picture of the risks associated with different levels of transmission augmentation. These include:

- the total energy beyond the continuous thermal capability in each year;
- probability of outage of transmission elements and generators;
- historical outage rates and/or benchmark performance standards of transmission elements and generators;
- the total energy beyond the 10-minute thermal capability[3] in each year;
- the number of separate occasions in each year in which the network would be required to operate beyond the 10-minute thermal capability;
- the maximum duration of a single event in which the 10-minute thermal rating is exceeded; and
- the maximum amount by which the demand exceeds the 10-minute network capability (which equates to the load which would need to be shed).

The "energy at risk"[4] is a critical parameter in justifying any network investment. The probabilistic approach to network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove any constraints; and
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, recognising that very extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional network capacity to meet all anticipated loading requirements. Rather, the probabilistic approach indicates that network augmentation should take place only when its cost is less than or equal to the value of the reduction in energy at risk.

The probabilistic planning approach is more compatible and consistent with a competitive market environment, since it allows an economic assessment to be made on the benefits achieved through network augmentation compared to net costs which Participants (including consumers) may sustain.

2.2 Investment Cost

VENCorp's investment criterion suggests that in principle a transmission augmentation should proceed when the total market cost of not proceeding exceeds the cost of the investment necessary to remove or reduce that cost. The costs considered are the capital, operation and maintenance costs associated with a proposed augmentation.

2.3 Investment Benefits

The benefits associated with augmentation of the transmission network are the avoided costs of non-provision of additional network capability. These costs include:

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3 The concept of 10-minute rating is explained in more detail in Appendix 2.

4 "Energy at risk" is the probability weighted value of the amount of energy that will not be supplied in a year because of network constraints. This value is calculated by using simulation models under scenarios considering a plausible range of generation and load patterns. The analysis takes into account key variables such as scheduled and forced generator outages, and weather impacts on the loading of transmission elements. These simulation studies indicate on an hourly basis the extent of demand that is in excess of the network capability, and this is then averaged over many scenarios to determine the amount of energy expected to lie beyond the network capability, on an annual basis.

- the value of any load that must be curtailed to ensure that the transmission system does not operate beyond its rated capability;
- changes in the cost of providing ancillary services;
- the additional net market cost of generating plant (both fixed and variable);
- reductions in the cost of active and reactive power losses; and
- deferment of other network investments.

2.4 Value of Energy at Risk

There are three aspects associated with determining the benefit of avoiding energy at risk.

2.4.1 How much energy is at risk?

As stated above, this is calculated by using simulation models under scenarios considering a range of generation and load patterns. This analysis takes into account the impact of scheduled and forced generator outages and weather impacts on the loading of transmission elements. These studies indicate on an hourly basis the extent of energy beyond the network capability, and this can be averaged over many scenarios to determine the energy expected to lie beyond the network capability on an annual basis. Figure 1 shows the flow chart for the assessment of the expected unserved energy and cost of expected generation re-dispatch.

2.4.2 How should energy at risk be valued?

The second important aspect is to determine how such energy should be valued. Energy at risk can be considered in two categories depending on the action required to remove it.

- Re-dispatch of generation and/or re-distribution of ancillary services which can alleviate some energy at risk. The cost of this is readily determined from the simulation model since the altered generation profile can be determined and the increased dispatch cost can be calculated from bid prices.
- In some cases energy at risk would be permitted since the consequences of an overload following the critical contingency can be controlled by automatic load shedding, use of short term overload capability and subsequent control action to avoid plant ratings being exceeded. In addition, any load beyond the 10-minutes network rating should be assumed to be shed on a pre-contingent basis to ensure the security of the power system in the event of a outage. The Value of Customer Reliability (VCR) is used to value load at risk under these circumstances.

2.4.3 What is the Value of Customer Reliability (VCR)

The third aspect is the value of customer reliability to be used in the assessment. In the transmission investment evaluation decisions, VENCorp applies a VCR of $29,600/MWh statewide. A sector specific VCR may be applied where transmission constraints affect a reasonably clearly distinguishable subset of Victorian load. Table 1 details sector specific values. Individual terminal station loading data will be used to identify subsets of the Victorian load for individual projects.

In Appendix 3, an example is illustrated with the above principles.

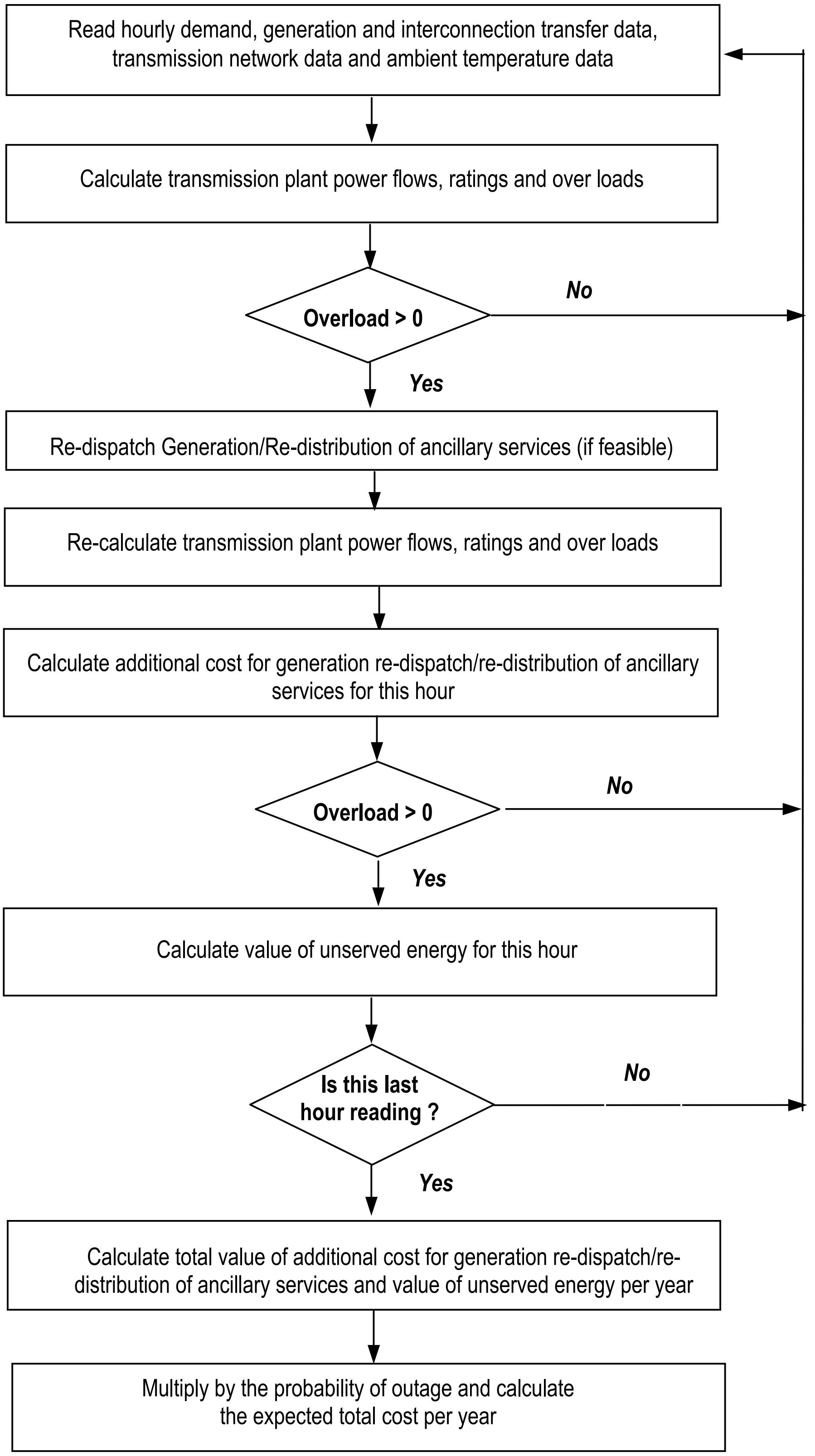

Figure 1 - Flow chart for assessment of cost of expected generation re-dispatch and expected unserved energy

2.5 Summary of Key Steps Involved in Undertaking a Transmission Network Economic Evaluation

The key steps involved in undertaking an economic evaluation are summarised below:

(a) Identify a network constraint for the existing transmission system at the forecast level of demand, taking into account the variability of temperature and plant availability.

(b) Identify transmission augmentation, demand management and other possible options to alleviate the constraint.

(c) Identify the costs of each option including:

- incremental generation costs (fuel, operations and maintenance, and capital);
- incremental ancillary services costs;
- incremental transmission costs; and
- incremental consumers' opportunity costs associated with the level of supply reliability provided by each option.

(d) Calculate the net present value of the market benefit[5] of each option over its life cycle (or alternatively, over a shorter period, with inclusion of appropriate allowances for residual values at the end of the study period).

(e) Select the option that maximises the net present value of the market benefit.

(f) Test the sensitivity of the net present value to changes in key assumptions, including the timing (i.e. deferral) of options, discount rate, capital and operating costs, and a range of alternative market development scenarios.

(g) Select the option and timing that minimises the net present value of the cost (or maximises net present value of the market benefit).

3 Technical Criteria

There are many technical factors that may impose limitations on the performance of the transmission network and need to be considered when determining and planning its capability for providing secure and reliable energy transfer between generators and customer loads. Many of these are described as the network performance requirements in schedule 5.1 of the National Electricity Code. This section discusses some of these factors and the strategies that are proposed for these areas into the future.

In order to maintain a secure system, the design principles and approach used by VENCorp for planning the transmission network are as follows:

- The system must be able to sustain any single outage, including disconnection of any single generator, busbar or transmission element, and remain within performance limits as defined in the National Electricity Code.
- Following the forced outage of a single network element, it must be possible to 're-adjust' the system within 30 minutes so that it is capable of tolerating a further forced outage without risk to the security of the overall network. This may involve network switching and/or modification to generation dispatch to account for the new system constraints. Blocks of load may be at risk of disconnection either directly by a second failure (such as

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5 A risk-adjusted commercial discount rate must be used to calculate present value costs and benefits of all options. That discount rate is to be consistent with prevailing capital market conditions, and relevant regulatory determinations. It will also be subject to periodic review, to reflect any material changes in relevant factors. VENCorp's present policy is to apply a discount rate of 8% real pre-tax, with sensitivities at 6% and 10% real pre-tax

for loads that are supplied by two lines where the first line is unavailable and the second line fails) or by load shedding action to ensure that the system is capable of remaining in a secure state if the second event occurs.[6]

- Adequate control measures are in place to secure the power system (ie. retain the system in a stable and controllable condition) and minimise the extent of disruption to customers following low probability events not catered for by the basic network design.
- Sufficient periods are available to allow maintenance of critical shared network elements without exposing the network to excessive risk in the event of a further unscheduled outage of a network element. These parts of the network must have sufficient capacity to reliably meet transfer requirements with two elements out of service during light load when maintenance is scheduled.

3.1 Thermal Capacity of Plant and Lines

The transmission network must be planned to operate within the thermal capability of transmission lines and transformers. The current carrying capacity of transmission plant is defined in terms of a maximum temperature that the equipment is able to sustain without plant damage, or in the case of transmission lines, the necessary critical clearances to the ground being maintained[7].

It is possible to temporarily operate a transmission line or transformer beyond the current level that would, if applied continuously, result in temperatures higher than equipment rating. Providing the equipment is operating below the temperature rating prior to an outage occurring, a sudden increase in current flow can be sustained for a short period of time before the temperature of the equipment rises to the rated temperature. Time constants for transmission lines are generally less than 15 minutes due to the low mass of metal involved. On the other hand transformers have a large iron mass and a large oil volume and take quite a long time to heat up. Time constants of the order of 30 to 45 minutes are typical.

In planning the transmission network in Victoria, VENCorp has made allowance for the short-term operation of transmission plant beyond continuous current ratings, allowing flows greater than the normal firm capability limit. The maximum acceptable normal flow (with all plant in service) is limited to a level such that plant items will not exceed their rated temperature within 10 minutes after an item of plant fails. A 10 minute rating is normally used to provide time for manual operating action to be taken to reduce the flow so that the temperature of the element is not driven beyond its rating. Application of short-term ratings is detailed in Appendix 2. The actions could involve transformer tap changing, reconfiguration of the network through switching or, in some cases, generator rescheduling and/or selective load curtailment. Where special automatic controls are implemented, the time allowed for post event load reduction may be shorter than 10 minutes. An automatic control scheme can permit the secure utilisation of short-term ratings of transmission plant.

It may not always be prudent to plan the network by taking full account of short-term overload ratings given significant uncertainty in load growth and the competitive market. However, the use of short-term ratings provides some flexibility should market outcomes for network capacity exceed planning expectation and therefore provides more confidence in planning the network to meet expected performance levels. It may also provide security for the period immediately prior to network augmentation where the risk associated with operating beyond firm capability is insufficient to justify augmentation.

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6 Overloaded elements may be tripped by protection schemes leading to further overloading of remaining elements and cascade tripping of large portions of the network and ultimately to complete shutdown of the entire network. Such an event would involve total loss of supply to all participants in Victoria (and perhaps across the interconnected system). A complete restart of the system may take many hours, mainly because of the unavailability of an electricity supply to start auxiliary plant for base load generation. The costs of such a "system black" event are difficult to estimate but are extremely high, perhaps up to $250 million per event. Pre-contingent load shedding may be required to ensure that such outcomes are avoided under extreme system operating conditions.

7 Transmission lines are designed so that certain clearances are maintained between the conductor and the ground ("statutory clearances"), the transmission towers or between phases. As the conductor expands with higher temperatures, the conductor sags further and these clearances are reduced. Beyond the design temperature the clearances will be reduced below acceptable levels and the risk of flashovers is increased. This is also an important safety issue since reduced clearances to ground increase the potential for accidents with machinery contacting lines with reduced clearance.

3.2 Transient and Oscillatory Stability

The power system's stability is determined by its ability to return to normal or stable operation after it has been subjected to some form of disturbance. If the power system becomes unstable, generating plant may be damaged and widespread loss of generators/load could occur.

The performance of large generating units connected to the network can be critical to the stability limits and lower standards of performance can reduce transfer capabilities of the network. The network design is based on large generating units meeting the generator technical requirements specified in the National Electricity Code.

The interconnected power system is designed to withstand a two-phase-to-ground fault at the most critical location, cleared within primary protection times with all transmission in service and under extreme operating conditions. The system is also designed for these conditions to be modified to allow for prior outage of the critical transmission element and less onerous conditions.

Under normal operating conditions, there are currently no transfer capabilities within Victoria, which are constrained due to transient or oscillatory stability considerations. The transfer capabilities on the interconnectors between Victoria and New South Wales/Snowy and between Victoria and South Australia are constrained by transient stability under some conditions. Although oscillatory stability is not limiting in the Victorian network, it may become an issue if the transient stability related capabilities are increased. An increase in the transient stability capability may be possible if improved analytical techniques indicate that higher transfers are possible without threatening system security.

The transient and oscillatory performance of the interconnected power system is reviewed from time to time to determine the validity of planning advice for operation. This advice is provided to NEMMCO to ensure system operation within safe transfer levels. The impact of planned transmission and generation developments is assessed prior to commissioning to ensure that operating advice is updated if required. This includes interstate developments where major projects have the potential to affect the Victorian transfer capabilities.

3.3 Voltage Control

The provision of a sufficient level of reactive support is essential to ensure that satisfactory voltage control of the power system can be maintained following a loss of a critical network element or generator, particularly under high summer loading conditions.

The severe implications of a loss of voltage control means that, during normal minute-to-minute power system operations, a capability margin is retained to guarantee that voltage control is not lost following any outage of a transmission element or generator.

Reactive power used for voltage control is provided in a number of ways:

- generators;
- synchronous compensators and static VAr compensators (SVCs)
- shunt capacitors;
- series capacitors; and
- shunt reactors.

The first two sources are fast acting and can be used to provide continuous control of voltage. They are able to provide rapid reactive support following loss of a critical network element or generator. Shunt capacitors and shunt reactors provide discrete blocks of reactive power and are appropriate to compensate slowly changing reactive demands associated with daily load variations. They are coordinated with fast acting sources to ensure that adequate margins are maintained in the fast acting devices to allow them to respond to sudden system changes. If the voltage moves outside the normal voltage range, the shunt capacitors and shunt reactors can operate automatically to restore satisfactory voltage levels within a short period.

The National Electricity Code specifies maximum voltage deviations of ±10% on nominal voltages for any operating condition, including following a network contingency. In practice voltage changes of this magnitude could not be tolerated at some locations due to the limitations in plant connected at the interface, and more stringent system voltage requirements in lower voltage networks. For example the lack of a large tapping range on some metropolitan 220/66 kV transformers provides a restriction on the minimum level for 220 kV voltages where a post contingency voltage drop of around 3% is considered the minimum desirable level.

The voltage change due to capacitor bank switching is also an important consideration in the design and location of new terminal station capacitor banks. As a general rule the voltage change is limited to ±2½% under system normal conditions.

The voltage control criterion is that stable voltage control must be maintained following the most severe credible contingency event. This requires that an adequate reactive power margin must be maintained at every connection point in the network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point.

3.4 Quality Of Supply

Customers require an electricity supply of appropriate quality, to ensure their electrical equipment and appliances:-

- will operate as designed and can be utilised to full design capability,
- are at minimal risk of damage when connected to the electricity supply system,
- will operate continuously when required, with minimal risk of interruption.

To meet these requirements it is necessary to maintain the supply voltage from the network at an appropriate standard, with the following electrical quantities maintained within appropriate limits:

- frequency
- voltage levels
- harmonic distortion of voltage,
- voltage variations,
- voltage unbalance

Appropriate limits have been defined in the National Electricity Code, based on overseas and Australian experience, so that present and future customers can have confidence that they will be provided with an electricity supply of adequate supply quality for the foreseeable future. Under the National Electricity Code, VENCorp is obliged to use its reasonable endeavours to maintain quality of supply at points of connection within the levels defined by Schedule 5.1 of the Code. VENCorp's obligation is subject to customers maintaining their quality of supply contribution at points of connection within the levels defined by Schedule 5.3 of the Code.

Participants and customers will be aware that modern electrical equipment, including industrial equipment, often has load characteristics with a significant non-linear component, caused by power electronic devices such as thyristors and rectifiers. Such electrical equipment will adversely affect their quality of supply by impacting on one or more of the above electrical quantities to some extent. Customers planning to connect such equipment to the electricity supply should realise that in some circumstances special measures may be required to ensure that their equipment does not cause the quality of supply to other customers to deteriorate outside standards defined by the National Electricity Code. Customers should be aware of their obligations under Schedule 5.3 of the Code to generally maintain their quality of supply contribution at points of connection within the levels defined in the Code or Connection Agreements.

A Participant may request a temporary higher allocation of an allowance specified in the National Electricity Code (Schedule 5.3), which has an influence on the quality of supply at the relevant point(s) of connection. An example would be a load that produces excessive harmonic distortion of the supply voltage. If no other significant distorting loads exist in the area, an increased but temporary allowance might be negotiated. This temporary allocation would depend on the pre-existing quality of supply distortion levels at the relevant point(s) of connection. Any such temporary higher allocation would be granted only if the relevant participant enters into an agreement to reduce their quality of supply contribution to within the National Electricity Code required levels, if reasonably required by

VENCorp. This may be necessary, for example, if another customer wishes to later connect a load, which would adversely contribute to the quality of supply at the point(s) of connection.

3.5 Fault Levels

The network must be operated within the fault breaking capability of circuit breakers to ensure that faulted plant can be removed from the system quickly and safely. Since many of the circuit breakers were installed, the fault breaking requirements have increased considerably as a result of increased network loading, additional lower impedance network elements and additional generation.[8]

At the time of station development, circuit breakers were selected with a fault breaking capability sufficient to cater for the expected growth over the 30 year anticipated life. It was also intended to progressively open 220 kV connections between stations and operate the 220 kV system with radial connections from the 500 kV network by installing 500/220 kV transformation around the outer 500 kV ring. However, these stations have not been developed and the utilisation of the 220 kV system has been maximised by retaining the connections as part of the meshed network.

This has resulted in the need to open some "ties" or specific transmission lines and transformers to restrict the maximum fault breaking duty of these critical circuit breakers. The original system configuration may be restored manually or automatically following critical network outages. This approach provides a workable arrangement allowing high network utilisation with little reduction in security while avoiding the high cost of wide spread replacement of circuit breakers.

Eventually, scope for opening parts of the system will be exhausted and replacement of circuit breakers will be required to enable operation at higher fault levels. Where possible this would be a staged process to limit replacement to specific areas to avoid widespread replacement. To further prepare for this need, the opportunity will be taken to uprate circuit breakers as SPI PowerNet replaces ageing plant.

4 Environmental And Social Impacts

Power system assets have actual and perceived environmental and social impacts on the community. To minimise community concerns, some of the factors considered when initially planning lines and stations include:

- Visual impact;
- Social dislocation;
- Electro Magnetic Fields (EMF);
- Greenhouse gas emissions;
- Community consultation including relevant professional independent specialist input; and
- Planning permit process.

5 Sites And Easements

There are a significant number of network station sites and some transmission line easements that have been reserved for anticipated future development of the network. These were reserved some time ago and the requirement for these is kept under review. A number of sites have been disposed of in recent years at locations where it is considered there is no longer a need for future development.

The existing easements and sites are a very valuable asset to the industry to allow planned development to occur in areas where future intentions have been made clear.

At present, ownership of the rights to easements and shared station sites has been vested with SPI PowerNet, who manage these properties on behalf of the industry and in consultation with VENCorp. It is intended that should there

8 The 220 kV circuit breakers are a particular problem in this regard. Most were installed in the 1960's prior to the development of the 500 kV system and significant power stations including Hazelwood, Yallourn West and Loy Yang.

be successful tenderers for projects that require these sites, that access would be provided by SPI PowerNet in accordance with its legal and regulatory obligations.

Appendix 1: ACCC Regulatory Test

On 15 December 1999, the ACCC published the "Regulatory Test for New Interconnectors and Network Augmentations" pursuant to section 5.6.5(q)(1), now deleted, of the National Electricity Code. The regulatory test is to be applied to transmission augmentation proposals in accordance with clause 5.6.2 of the National Electricity Code.

A new interconnector or an augmentation option satisfies this test if it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios.

An augmentation satisfies this test if:

(a) in the event the augmentation is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the augmentation minimises the net present value of the cost of meeting those standards; or

(b) in all other cases – the augmentation maximises the net present value of the market benefit

having regard to a number of alternative projects, timings and market development scenarios.

For the purposes of the test:

a) market benefit means the total net benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios. The benefits associated with augmentation of the transmission network are the avoided costs of providing the additional network capability. These costs include;

   - the value of any load that must be curtailed to ensure that the transmission system does not operate beyond its rated capability;
   - changes in the cost of providing ancillary services;
   - the additional cost of generating plant (both fixed and variable costs); and
   - reductions in the cost of losses.

b) cost means the total cost of the augmentation to all those who produce, distribute or consume electricity in the National Electricity Market;

c) the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector;

d) the calculation of the market benefit or cost should encompass sensitivity analysis with respect to the key input variables, including capital and operating costs, the discount rate and the commissioning date, in order to demonstrate the robustness of the analysis;

e) a proposed augmentation maximises the market benefit if it achieves a greater market benefit in most (although not all) credible scenarios; and

f) an augmentation minimises the cost if it achieves a lower cost in most (although not all) credible scenarios.

Appendix 2: Short Time Ratings

Historically the network was designed and operated in accordance with an (n-1) planning standard. That is to say, sufficient redundancy was built into the network to allow an unexpected outage of a single transmission element to occur without risk of supply interruptions, and so that the rating of other transmission plant would not be exceeded. This ensured that no damage would occur to the transmission elements and that no curtailment of load or generation would be necessary.

More recently short-term equipment ratings have been used to provide increased transmission utilisation. This recognises that the temperature of a transmission element exposed to a sudden loading increase after an outage will take some time to reach its thermal rating. This is due to the mass of metal involved. The use of a 10-minute rating has been adopted, so that following a contingency system operators have ten minutes to reduce loading on critical transmission elements before their temperature rating is exceeded. In some cases the use of less than 10-minute ratings have been employed with an automatic control scheme. An automatic control scheme can permit the secure utilisation of short-term ratings of transmission plant.

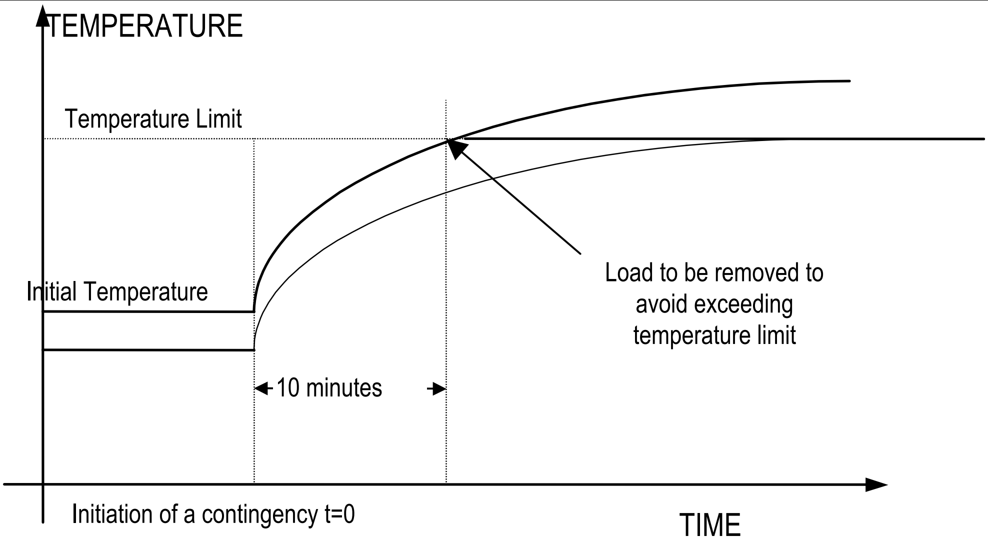
This approach has become more feasible over the last decade due to the higher level and accuracy of remote monitoring of critical aspects of the transmission system, to allow much tighter control. Given the rare occasions on which the capability is exceeded it is relatively easy to develop rigorous procedures to apply under critical loading conditions to ensure that response is achieved within the required time frames.

It is recognised that higher utilisation could be achieved if even shorter term ratings were adopted (ie, if system operators were required to act in less than 10 minutes). In the event that network loading did exceed the 10-minute rating (for example due to higher than forecast load) this approach would be likely to be adopted in preference to taking pre-contingent action (such as load shedding). In planning the network this additional capability is reserved for those rare occasions when the network operation may be more extreme than that anticipated in network planning studies, or to cover the period immediately prior to the augmentation when the energy at risk is insufficient to justify augmentation[9].

Plant ratings depend on ambient temperature since greater heating of the conductor due to the passage of current is allowed at lower ambient temperatures. Another important consideration is that temperature will not rise instantaneously following a sudden increase in flow. Due to the mass of metal that is heated, the temperature rises more gradually. Assuming that redundancy is built into the network the flow prior to a contingency will be somewhat less than its continuous rating and the conductor temperature will be at a relatively low value.

9 In some special circumstances the network may actually be designed to operate beyond ten minute ratings, however this requires provision of automatic control schemes to ensure the required response can be achieved. It is most frequently adopted where there is considered a higher than normal probability of a double contingency and it is prudent to make some provision for ensuring system security.

Example of application of 10-minute rating



Following outage of one 100 MW line of a double circuit line, the current flow will increase on the remaining 100 MW line and the temperature of that line will begin to rise. However there will be time available in which to take action to ensure that this rise is contained within conductor temperature limits. This is shown in the following diagram.

This illustration shows that it is possible to operate beyond the firm (n-1) capability without compromising on system security providing action is taken after the contingency to bring the loading within the continuous rating before the maximum conductor temperature is exceeded. In this case the lower curve shows the situation that would exist if no short-term overload capability was adopted. For this example it corresponds to an initial line loading of 50 MW which following the outage increases to 100 MW, just sufficient to increase the conductor temperature to its rating.

The higher curve indicates the temperature that results if initial operation is allowed at higher levels. In this case the conductor temperature rises after the outage and if left unchecked would increase beyond the thermal rating of the line after 10 minutes. However, with facilities in place to remove the overload within the ten minutes, temperature ratings would not be exceeded.

A10-minute response time is considered acceptable. If higher loading was used then temperature ratings and perhaps plant damage would occur prior to the ten minute period allowed for operators to act. Consequently this sets the maximum pre-contingent loading which is allowed, and any load beyond this level should not be transferred since it leads to the risk of plant damage and ultimately, loss of system security.

Appendix 3: Example of assessment of energy at risk for economic justification

Assuming a VCR of $29,600/MWh, some indication can be gained of the level of risk which may be economically justified before an investment in the network should proceed. Applying an (n-1) supply reliability standard, then in the above example, an additional 100 MW transmission line would be required in parallel with the existing lines to remove the constraint. However, this (n-1) standard is not applied in the assessment of supply reliability. Load at risk is determined and valued, and the cost of the investment is then compared with the expected benefit (reduced load at risk), as follows:

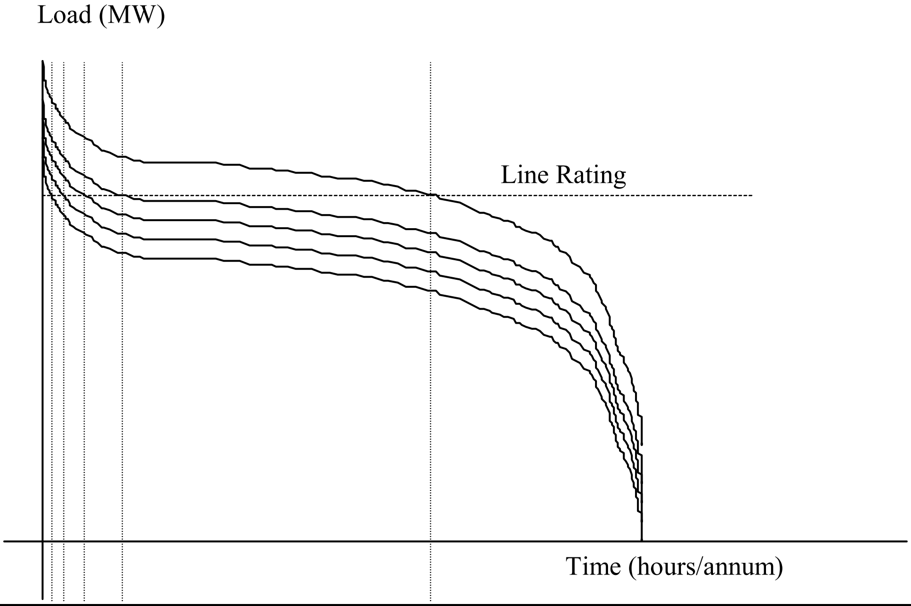
Capital Cost (of additional 220 kV line) = $20 million

The equivalent annual cost over the project life = $2.5 million per annum

With VCR at $29,600 per MWh this equates to about 85 MWh of load not supplied.

For a situation where the maximum demand was anticipated to be 105 MW the project could not be justified, since it is likely that loads up to this level would be achieved for 10 - 20 hours per annum at most, ie. 25 to 50 MWh of expected unserved energy[10].

However the expected unserved energy grows dramatically as load increases. This can be seen from consideration of a load duration curve, which shows the period of time that load exceeds a certain value. If load growth is around 5% per annum, the demand beyond the firm capability will increase by around 5 MW each year but in addition the period of exposure will increase dramatically. After one more year, up to 10 MW may be exposed for up to 40 hours, resulting in expected unserved energy of 200 MWh and the project would be justified in that year.



While the above example exaggerates the typical situation by showing a high average load with respect to the peak, the principle is well illustrated. In initial years when the load just exceeds the critical rating the exposure is very slight. However this increases rapidly as load grows, both in terms of the demand which is at risk and the period of exposure. In general, given the scale of economies that exist, transmission investment is likely to be justified two to three years after the initial exposure.

10 The calculation of expected unserved energy at risk assumes that (i) the ten minute rating of the line is 100 MW, and therefore all load above 100 MW would need to be shed pre-contingent; (ii) the probability of the line outage is very low and the expected unserved energy when load is between the firm and ten minute ratings is assumed to be negligible; and (iii) the load would typically not be at the peak level of 105MW over the entire duration of any overload.