APPENDIX F

Powerlink Planning Criteria

June 2010

Powerlink Queensland 2013–2017 Revenue Proposal

PLANNING CRITERIA

Grid Planning			
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TABLE OF CONTENTS

1 OBJECTIVE

Powerlink is the sole holder of the transmission authority in Queensland, which authorises it, under the Queensland Electricity Act, to operate the high voltage transmission grid in the east coast part of Queensland. Powerlink is also registered as a Transmission Network Services Provider (TNSP) in the NEM, and must comply with the relevant National Electricity Rules.

Under the Queensland legislation, Powerlink has the responsibility to plan for the future Queensland transmission needs, including the interconnection with other networks. These planning responsibilities are defined in the National Electricity Rules (NER), the Electricity Act 1994 and in Powerlink Queensland's Transmission Authority issued by the Queensland Government.

A salient feature of the arrangements in Queensland is that Powerlink has mandated reliability obligations that drive non-discretionary investment in grid augmentations as the load grows.

These mandated obligations include a requirement to apply "good electricity industry practice" which in-turn necessitates a range of supporting technical standards. These mandated obligations along with the technical standards are referred to as the "planning criteria". Whilst the components or detail of the "planning criteria" are not specifically defined by the NER or in the State Government legislative requirements, the "planning criteria" must be defined and documented such that the required statutory outcomes are achieved. This paper documents the components of Powerlink's "planning criteria".

2 STATUTORY OBLIGATIONS

As a transmission network service provider (TNSP), Powerlink must comply with the requirements of Schedule 5.1 of the National Electricity Rules (NER) and in particular, Schedule S 5.1.2.1:

> *"Network Service Providers must plan, design, maintain and operate their transmission networks and distribution networks to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events").*
>
> *The following credible contingency events and practices must be used by Network Service Providers for planning and operation of transmission networks and distribution networks unless otherwise agreed by each Registered Participant who would be affected by the selection of credible contingency events:*
>
> *(a) The credible contingency events must include the disconnection of any single generating unit or transmission line, with or without the application of a single circuit two-phase-to-ground solid fault on lines operating at or above 220 kV……"*

The Queensland Electricity Act 1994, S34 also includes a responsibility to:

> *"ensure, as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and, if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorized to connect to the grid or take electricity from the grid…."*

In addition the Queensland State Government has issued a "Transmission Authority – No. T01/98" to Powerlink Queensland. Clause 6.2 of this Transmission Authority requires that:

> *"Plan and develop its transmission grid in accordance with good electricity practice such that:*
>
> *(a) If the power quality standards specify different obligations during normal and other operating conditions – the power quality standards will be met by the transmission entity;*
> *(b) If the power quality standards do not specify different obligations during normal and other operating conditions – the power quality standards will also be met by the transmission entity even during the most critical single network element outage; and*
> *(c) The power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage.*
>
> *The obligations imposed on the transmission entity by clause 6.2 will apply unless otherwise varied by a connection or other agreement made by the transmission entity with a person who receives or wishes to receive transmission services."*

Powerlink has connection agreements with each of the parties connecting to the transmission network. These connection agreements include obligations regarding the reliability of supply as required under Schedule S5.1.2.2 of the NER. The connection agreements generally require that capacity is required to be provided to a supply point or area such that forecast peak demand can be supplied with the most critical element out of service, without the necessity to interrupt customer load (i.e. N-1).

3 JURISDICTIONAL PLANNING REQUIREMENTS - RELIABILITY STANDARD

Clause 6.2 of the Transmission Authority requires Powerlink to plan and develop its transmission network according to an "N-1" criterion. That is, unless specifically agreed otherwise with the affected distribution network owner or directly connected major customer, there will be no loss of load (other than load that is interruptible or dispatchable) following a single credible contingency event. This mandated reliability of supply obligation drives non-discretionary investment in grid augmentation as the load grows.

Credible contingency events that Powerlink must take into account when assessing whether the network meets this reliability standard are defined in Schedule 5.1.2.1 of the NER. These events include the disconnection of any single generating unit (extended to consider large individual customer loads) or transmission line/plant, with or without the application of a single circuit two-phase-to-ground solid fault on lines operating at 330kV or 275kV.

When considering the application of a fault, Schedule 5.1.2.1 of the NER allows the fault to be cleared in primary protection time by the faster of the duplicate protection schemes with installed intertrips available.

Meeting this "N-1" criterion means that following the single contingency event, the power system settles to a new "satisfactory" operating state without the need to shed non-interruptible load immediately after the contingency. The network should have sufficient capacity to accommodate AEMO's operating practices which include the re-dispatch of generation and ancillary services following a first contingency, such that within 30 minutes, the power system can again be returned to a "secure" state . The satisfactory and secure operating state aspects of the "N-1" criteria are outlined in sections 3.1 and 3.1 below.

3.1 Satisfactory Operating State

What constitutes a satisfactory operating state is described in Chapter 4.2.2 of the NER.

" The power system is defined as being in a satisfactory operating state when:

(a) the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band;
(b) the voltage magnitudes at all energised busbars at any switchyard or substation of the power system are within the relevant limits set by the relevant Network Service Providers in accordance with clause S5.1.4 of schedule 5.1;
(c) the current flows on all transmission lines of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;
(d) all other plant forming part of or impacting on the power system is being operated within the relevant operating ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;
(e) the configuration of the power system is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and
(f) the conditions of the power system are stable in accordance with requirements designated in or under clause S5.1.8 of schedule 5.1"

Schedule S5.1.8 of the NER requires:

(a) the power system to remain in synchronism;
(b) power system oscillations to be adequately damped; and
(c) voltage stability criteria to be satisfied.

following any credible contingency event.

These power system stability criteria are further defined in Section 4.4.

3.2 AEMO's Obligation to Return the Power System to a Secure State

Section 4.2.4 of the NER (Secure operating state and power system security) defines a secure operating state as:

"(a) The power system is defined to be in a secure operating state if, in AEMO's reasonable opinion, taking into consideration the appropriate power system security principles described in Section 4.2.6:

(1) the power system is in a satisfactory operating state; and

(2) the power system will return to a satisfactory operating state following the occurrence of a single credible contingency event in accordance with the power system security and reliability standards."

Section 4.2.6 of the NER (General principles for maintaining power system security) defines AEMO's obligations with regard to operating the interconnected power system in a secure state.

"The *power system security* principles are as follows:

(a) To the extent practicable, the power system should be operated such that it is and will remain in a secure operating state.

(b) Following a contingency event (whether or not a credible contingency event) or a significant change in power system conditions, AEMO should take all ***reasonable actions****:*

(1) to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within thirty minutes;"

Actions considered reasonable by AEMO to return the power system to a secure operating state include:

- Re-dispatch generation and dispatchable load;
- Re-distribute ancillary services; and
- Where there is no other alternative, shed load.

The initial response of AEMO will be to redispatch available generation and/or load to return the system to a new secure state. As such, the generation assumptions used to assess whether or not this can be achieved may be quite different from those assumptions used to assess the reliability standard for the initial single contingency event (N-1). The most notable difference may be the maximum dispatch of any available energy limited plant following the initial contingency. These generation assumptions are dealt with in more detail in Section 4.2.2.

If AEMO cannot return the power system to a secure operating state following an initial contingency without the need to shed non-interruptible load immediately following this first contingency, then the power system fails to meet the required planning reliability standard.

However, if load (even non-interruptible load) can be shed following the second contingency such that the system then falls to a satisfactory operating state, then the power system meets the required planning standard.

For convenience, this requirement will be referred to as meeting the (N-1 Secure) reliability standard throughout the rest of this document.

The requirement to shed load either immediately following the first contingency or following the second contingency depends on the failure mode of the system when subjected to the second contingency.

If the power system is dynamically unstable (transient or oscillatory) in the event of the second contingency, then load must be shed pre-contingent. However, if the limitation is the thermal rating of plant, then the response to place the system at a satisfactory operating point may be post-contingent. If the failure mode is voltage instability then the required timeframe for the load-shed response must be carefully considered. These are discussed in further detail in Appendix A.

4 THE RELIABILITY STANDARDS ARE TO BE MET UNDER THE FOLLOWING TECHNICAL STANDARDS

Following is a discussion of each component of the planning criteria. The components are the building blocks that together define the technical standards under which Powerlink will meet its statutory obligations.

Unless specifically defined otherwise, these technical standards apply equally to the assessment of the reliability obligations under the initial single contingency event (N-1) and when assessing whether or not AEMO is able to reposition the power system into a new secure state following this initial contingency. Powerlink meets its statutory obligations to deliver a network for AEMO to operate securely over a range of reasonably probable conditions.

4.1 Load Forecast

The load forecast used will be based on that published in Powerlink's most recent Annual Planning Report. If planning for a local supply area, zone adjustments will be made to the load forecast.

Planning of the main transmission system will be based on meeting the 10% PoE medium economic load growth forecast (zonal or multiple zones), which is consistent with good industry practice. This extends to the provision of adequate transformation capacity at Powerlink's major substations that supply bulk power to each of the zones.

Consistent with DNSPs, the 50% PoE medium economic load growth forecast is to be used to identify the limitations within the zones. Allowance is made to consider the 50% PoE zone or local peak forecast.

4.2 Generation

In assessing whether or not the reliability obligations can be met, standards relating to generation availability, dispatch and capability are of importance. The generation standards under which this assessment is to be done must take account of:

- Number of generating units of influence in the area or zone;
- Age, technology and reliability record of this plant;
- Energy limitations of the plant (if applicable);
- Any external factors (eg water availability, fuel supply, environmental restrictions etc) that may impact on the generation capacity (both short and long term) and availability of plant; and
- Any linkages that may exist between different generation sources within a zone or region with respect to critical resource availability (e.g. water, fuel). Such linkages mean that if one of the power stations is experiencing constraints, there is a high likelihood that several of the other power stations may also be constrained for similar reasons or be constrained as an operating consequence from the constraint on the first power station.

These issues require individual consideration for each of the zones or areas of the Queensland network.

4.2.1 Coincident Generator Outage

Generator outages are an inevitable occurrence in any power system, including the NEM. Notwithstanding best operating and maintenance practices, full availability of generation can never be guaranteed. In addition, hot weather conditions can place additional stress on plant and increase the likelihood of failure. Generating plant outages coincident with hot ambient temperatures (and hence high load conditions) are not uncommon.

As generators have significantly lower availabilities than transmission network elements, reliance on any individual generating unit cannot be made when considering network reliability obligations.

As a result, Powerlink plans and develops its transmission grid in accordance with good electricity practice such that power quality and the reliability standards, defined in the NER and in Powerlink's Transmission Authority, are met under a number of generation dispatch patterns including consideration of the most critical generation unit outage affecting the area or zone of study.

4.2.2 Generation Output of Energy Limited Plant

Energy limitations are more likely at hydro, wind, biomass and liquid fuel generating plant.

For the hydro plant, consideration must take account of the age, historical generation patterns, market dispatch patterns, load profile, water storage capacity and other water uses (eg irrigation, tourism).

Taking these factors into account, the following effective capacity assumptions are used for the hydro generating units in north Queensland:

- Kareeya Power Station – 63MW;
- Barron Gorge Power Station – 15MW; and
- K5 Power Station – 6MW.

In southern Queensland, the generation output of the Wivenhoe pumped storage scheme is limited by the size of the upper storage dam, system black start obligations and the availability of commercially suitable opportunities to restore the upper dam level by pumping. To reflect the above energy limits over the extended summer load profile, the effective output of Wivenhoe is assumed to be limited to 150MW.

Generating plant fuelled by bagasse do not usually operate during summer high demand periods as these occur after the sugar cane crushing season. In addition, consideration needs to be given to:

- Possible drought during the growing season reducing bagasse stocks;
- Possible early wet season reducing usability of stored bagasse during the summer season;
- Transportation and available bagasse storage facilities; and

- Prevailing network support agreements where they are possible.

These considerations determine the capacity available during periods of peak demand. Where grid support is not contracted a capacity factor of zero is applied. Where grid support is contracted a capacity factor of 50% is applied.

When assessing whether or not the power system can be returned to a secure state following an initial single contingency event, the output from energy limited plant may be extended by an appropriate level.

4.2.3 Generation Output of Intermittent Plant

For wind generators, coincident prevailing wind resources during periods of peak demand are generally only a small fraction of each machine's full capacity. In planning the transmission network for peak load conditions, a capacity factor of 5% is assumed. This capacity factor is consistent with operating experience in other states, which have significant wind generation.

When assessing whether or not the power system can be returned to a secure state following an initial single contingency event, the output from intermittent plant is assumed to be the same as output at peak load conditions, viz. 5% capacity factor.

4.2.4 Reactive Power Capability

Unless otherwise contracted, the reactive power capability of all generators is assumed to conform to their registered performance standards.

AEMO currently contract for additional reactive power capability from the following generator:

- Wivenhoe Power Station in synchronous compensator mode.

The current AEMO contract is until 30 June 2011 with an option to extend for an additional year to 30 June 2012. For the purposes of this criteria it is assumed that synchronous compensation from Wivenhoe is available if required (either as an ancillary service from AEMO or as network support if economic).

4.3 Rating of Transmission Equipment

The NER prescribes that the current flows on all transmission lines and plant of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) defined by the relevant Network Service Providers in accordance with Schedule 5.1.

4.3.1 Transmission Lines

For planning the network, Powerlink has formulated a criterion for rating transmission lines. The criterion involves using fixed ratings for both system normal operation and following a contingency event, which will prevent line conductors violating statutory clearances under a range of expected ambient conditions. Powerlink publishes its transmission line ratings on its web site.

For system normal operation, the sustained flow on a transmission line must not exceed the normal continuous rating.

The maximum sustained flow on a transmission line following a contingency is based on not exceeding the contingency rating. The contingency rating is based over a shorter time span than the normal continuous rating and therefore presents opportunity for a slightly higher rating without increasing risk.

Where appropriate, consideration can be given to reduce the loading on a critical transmission line to within this contingency rating by network switching and/or selective load curtailment (load that is interruptible or dispatchable). These responses must be automated or achievable within 10 minutes of the occurrence of the contingency.

4.3.2 Transformers

For system operation, Powerlink has assigned normal cyclic, emergency cyclic, short term emergency (2-hour) and short term maximum ratings for each transformer. For planning the network, the same ratings are applied with the following guidelines:

Powerlink's transformer rating policy is based on not exceeding the emergency cyclic rating following a contingency event and any subsequent mitigating action to curtail the loading (eg load transfer between connection points and/or network switching).

Under no circumstances is the immediate post contingent loading of the transformer to exceed the short term maximum rating.

If the initial flow through the transformer exceeds the short term emergency (2-hour) rating, then any mitigating action to curtail the loading must be automated.

4.4 Power System Stability

Schedule S5.1.8 of the NER requires the power system to be stable following any credible single contingency event. Instability can manifest itself as angular, oscillatory of voltage instability.

4.4.1 Transient Stability

Transient stability is assessed on the basis of rotor angle swings following credible contingency events. These contingencies can include the trip of a generating unit or customer load, or an outage of a transmission element. In accordance with the NER, if the critical contingency is an outage of a transmission element then this is preceded by the application of a solid two phase-to-ground fault on one circuit at the most critical location. The fault is cleared by the faster of the primary protection systems with the full availability of intertrips.

4.4.2 Oscillatory Stability

The requirements for controlling oscillatory stability are defined in Schedule 5.1.8 of the NER. For planning purposes, oscillatory stability (or system damping) is considered to be adequate under any given operating condition if, after the most critical contingency, predictions indicate that the halving time of the least damped electromechanical mode of oscillation is not more than 5 seconds.

The prediction of the oscillatory stability performance of the system is undertaken using software and models that has been calibrated against system tests.

4.4.3 Voltage Stability

Schedule 5.1.8 of the NER defines the general requirement for voltage stability:

> *"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 a network with respect to the voltage stability limit as determined from the voltage/reactive load characteristic at that connection point. Selection of the appropriate margin at each connection point must be at the discretion of the relevant Network Service Provider, but must not exceed a capacitive reactive power (in MVAr) of one percent of the maximum fault level (in MVA) at the connection point."*

The voltage stability limits for various parts of the transmission system are assessed by determining the maximum power transfer (or load level) above which the reactive power margins are no longer preserved at key buses following a critical credible contingency.

The assessment methodology does not allow for the determination of the reactive power (MVAr) margins at every connection point in the network. Rather, Powerlink recognises the existence of "coherent bus groups" and therefore selects key buses that will be reasonably representative of buses in the neighbourhood. In general, different MVAr margin observation buses will be selected to determine different transmission limits for different contingencies. The appropriate MVAr margins of these key buses will be reassessed from time to time, but are not less than 1% of the maximum fault level at that bus.

In making this assessment Powerlink is also cognisant of the effect high levels of reactive power compensation have on the characteristics and operability of a heavily loaded network. Therefore, maintaining reactive power margins by adding ever increasing amounts of reactive power compensation is not sustainable. High levels of compensation erode key operational measures such that bus voltage is no longer a reliable indicator of system health or proximity to voltage instability. In fact voltage instability may occur at voltages within operational limits. Such system characteristics must be avoided.

The assessment of system performance must also comply with the power quality system standards as defined in schedule 5.1a.4 to schedule 5.1a.7 of the NER.

Appendix B discusses in more detail the modelling assumptions to be adopted when assessing voltage stability.

The voltage stability limits of the power system are very dependent on the location and capability (both real and reactive power) of generators. The generation assumptions to be applied have previously been discussed in Section 4.2. Of great significance also are the power factor of the load and the availability of static capacitor banks, both at the transmission and distribution voltage levels.

4.4.3.1 Load Power Factor

The load power factor to be applied is obtained for the DNSPs and major customers during the load forecasting process. Powerlink prepares reactive forecasts in consultation with DNSPs and major customers connected to the Powerlink network. The resultant power factor is then used to determine the reactive load at other demand levels (e.g. 10% PoE) with adjustments as appropriate.

4.4.3.2 Capacitor Bank Availability

With consideration of the historical availability of capacitor banks in both the transmission and distribution networks, and the uncertainty of the uncompensated reactive load, system analysis is to assume less than 100% availability of all capacitor banks.

For the analysis of large parts of the network (multiple zones) the following guidelines are given:

- Assume 100% availability of capacitor banks installed at the load bulk supply points and connected to 66kV, 33kV, 22kV and 11kV voltage levels;
- Assume 100% availability of capacitor banks connected to the 132kV and 110kV voltage level; but
- De-scale the capacitor banks connected to the 275kV transmission system by 5% to allow for the fact that at any one time not all capacitive compensation equipment is available.

For analysis within a zone the discrete unavailability of a capacitor bank may be considered, instead of the averaged approach above, if appropriate.

4.5 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.

At no time should the contribution that the circuit breaker must interrupt of the total fault current, or the through current exceed the plant capability.

These short circuit currents are calculated assuming:

- All scheduled network generators are in-service;
- Fault level contributions from significant embedded non-scheduled generators are included in the analysis;
- Generators are modelled as 110% of nominal voltage behind sub-transient reactance;

- Classical network model is used where all transformer taps set to 1 pu and system loads and all shunt admittances not represented;
- Maximum fault contribution from inter-regional interconnections; and
- Normally open connections are treated as open.

AUTHORISATION

22 / 6 / 2010

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24 / 6 / 2010

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Planning Criteria Summary

	Comments	Criteria
Reliability Standard	The Transmission Authority requires Powerlink to plan and develop the transmission grid in accordance with good electricity industry practice such that power quality and reliability standards in the NER are met for intact and outage conditions, and the power transfer available through the power system will be adequate to supply the forecast peak demand during the most critical single network element outage, unless otherwise varies by agreement.	Meet forecasted peak demand following credible contingencies (N-1) as defined in the NER. Check that a sustained contingency can be managed without pre-contingent load shedding by operational means within the time for AEMO to achieve a secure operating state. This should consider a further contingency either transmission or generation (N-1 Secure).
Economic Growth Rate	Normal planning is based on the medium economic growth forecast. For the scenario planning process high, medium and low economic growth forecasts are used as appropriate.	Medium economic growth forecast is used as the base planning case. High, medium or low as required for scenario analysis.
Load Forecast	Due to an increased reliance on electricity, consumers are demanding a high standard of reliability of electricity supply. Consistent with other TNSP's in the NEM, Powerlink plans its interconnected main transmission network such that reliability of supply can be maintained following a single contingency for loads that are forecast to be exceeded only one year in ten. In making this assessment Powerlink also takes into account AEMO's requirement to return the system to a new secure state following the first contingency.	10% PoE medium economic load growth forecast (zonal or multiple zones) used for planning the main transmission system and 275/132kV and 275/110kV transformation capacity. 50% PoE medium economic load growth forecast used to identify the limitations within the zones. Allowance is made to consider the 50% PoE zone or local peak forecast.
VAR forecast	Use MVAr forecasts (based on 50% POE demand forecast) as supplied by the DNSPs and major customers (accounting for the effect of planned downstream capacitors). Where customer load power factor is non-compliant with the NER requirements corrections are	Use forecasted power factor as provided to scale reactive power to other demand levels with adjustments as appropriate.

Planning Criteria Summary

	Comments	Criteria
	made on the assumption that such shortfall will be identified and corrective action undertaken by the customer to ensure compliance.	
Availability of Capacitor banks	Both transmission and distribution level capacitor banks may be unavailable. There is also some uncertainty in the uncompensated reactive component of the load.	For analysis of multiple zones de-rate the capacitor banks connected to the 275kV transmission system by 5% to allow for the fact that at any one time not all compensation equipment is available. For analysis within a zone the discrete unavailability of an individual capacitor bank may be considered if appropriate.
Coincident generator outage	The reliability standard must be met for different generator dispatch patterns. This includes less than optimal generation within the import area/zone of interest. Such dispatches should make allowance for the outage of the largest generating unit.	Include consideration for the outage of the largest generating unit or the unit that has the greatest impact. Large areas or zones require special consideration. Based on the age, mix and number of generating units, the overall reduction in available generation capacity may exceed that of one generating unit.
Generation assumptions energy limited plant	Energy limitations exist at hydro, liquid fuel and biomass generating plants. These limitations are to apply when assessing the adequacy of the transmission system to meet the forecasted peak demand.	Barron Gorge - 15MW Kareeya – 63MW K5 – 6MW Wivenhoe – 150MW
Generation	Generation capacity limitations exist for wind plant. These limitations are to apply when assessing the adequacy of the transmission system	In planning the transmission network for peak load conditions, a capacity factor of 5% is assumed for

Planning Criteria Summary

	Comments	Criteria
assumptions intermittent plant	to meet the forecasted peak demand.	wind generation.
Transmission Line rating	Ratings for both system normal operation, and following a contingency event, are used consistent with good industry practice.	System normal operation – normal continuous ratings Post-contingency operation – contingency ratings Allow post-contingent switching and/or other strategies to reduce the loading to within the "contingency" rating. Such actions must be achieved within a 10-minute window. Energex and Ergon plant ratings are to be applied as advised.
Transformer ratings	Powerlink's transformer rating policy is based on not exceeding the emergency cyclic rating following a contingency event and any subsequent mitigating action to curtail the loading (e.g. load transfer between connection points and/or network switching).	System normal operation – normal cyclic rating Initial post-contingency operation < short term maximum rating Sustained post-contingency operation – emergency cyclic rating Contingency (initial) – manual load mitigating strategies if < short term emergency rating (2 hour)

Planning Criteria Summary

	Comments	Criteria
Generator Reactive Power Capability	AEMO currently contract for additional reactive power capability from the following generators: Wivenhoe Power Station The current contract expires 30^{th} June 2011.	Unless otherwise contracted, the reactive power capability of all generators is assumed to conform to their registered performance standards.

APPENDIX A

Issues to be considered when assessing whether the Power System can be return to a Secure State following the initial contingency (N-1 Secure)

If AEMO cannot return the power system to a secure operating state following an initial contingency (N-1) without the need to shed non-interruptible load immediately following this first contingency, then the power system fails to meet the required planning reliability standard.

The requirement to shed load either immediately following the first contingency or following the second contingency depends on the failure mode of the system when subjected to the second contingency.

If the power system is dynamically unstable (transient or oscillatory) in the event of the second contingency, then load must be shed pre-contingent. However, if the limitation is the thermal rating of plant then the response to place the system at a satisfactory operating point may be post-contingent. If the failure mode is voltage instability, then the required time frame for the load-shed response must be carefully considered.

Mode of System Failure	Issues
Dynamic Instability	• Post-contingent load shedding is **not** a solution • Generation must not be dispatched beyond the secure operating envelope for dynamic stability • In practice this envelope would be defined by an equation: ➢ Allowance should be made for typical confidence intervals and other off-sets imposed by AEMO.

Thermal overload	• Post-contingent load shedding may be a solution • Immediately following the contingency (but prior to load shedding) the flow **can** exceed the contingency rating. Immediate post-contingent flow must **not** exceed protection load limits or short term maximum rating of transformers: ➢ Generation must not be dispatched beyond the envelopes defined by these limits; ➢ Post-contingent load shedding is not an option to allow operation beyond these limits; and ➢ In approaching these upper limits, consideration must be given to an adequate safety margin (ΔP) – particular where trips could be initiated for transient flows in excess of these limits (Relay Load Limits or transformer protection limits). • Load shedding must occur in a timeframe that ensures that the post-contingent conductor temperature does not exceed the design temperature. The criterion is that 10 minutes must be preserved.

Voltage Instability	• The viability of post-contingent load shedding as a solution to arrest voltage instability depends on the speed of the voltage collapse: ➢ Speed of collapse will depend on: • Magnitude of the system loading above the firm capability; and • Strength of the immediate post-contingent system as it affects the ability of induction motor (IM) load to reaccelerate. ➢ Speed of load recovery cannot be assessed reliably without detailed dynamic analysis that includes realistic dynamic load models. Most documented voltage collapses are slow processes. However, transient voltage collapse may occur. This failure mode is more likely to occur in power systems that: • are heavily loaded; • have large % of IM load (air conditioning etc); and • are heavily compensated with capacitor banks. MVArs from these capacitor banks reduce (proportional to the square of the voltage) as the voltage reduces. This compounds the problem for re-acceleration of IMs. ➢ The risk of transient voltage instability is managed by ensuring there is sufficient reactive power margin to facilitate the initial recovery of the load. • The amount of load shed required to arrest a slower voltage collapse and to land the system in a satisfactory state should also be limited. Put another way; limit the amount by which the power transfer (or system load) exceeds the firm capability of the system. The larger the violation of the firm transmission capability, the higher the risk that post-contingent load shedding will not be successful in arresting the voltage collapse. • Post-contingent undervoltage load shedding is only viable to extend the loadability of the system if the load to be shed is located within the area/zones where the voltage collapse originates (i.e. where the reactive power reserve problems originate). The reason is that if the problem is insufficient reactive reserves at the "sending end" (e.g. CQ) then falling voltage levels at this end may put the bulk power transmission corridor (e.g. CQ-SQ) at risk of voltage collapse before the problem is observed in the "receiving end" where the load is to be shed.

APPENDIX B

Voltage Stability Assessment Methodology

In assessing the post-contingent reactive power margin the following assumptions apply:

- The system intact voltage profile is set to minimise the need for post-contingency reactive power support. This is achieved through adjustment of transformer tap positions (both at transformers under manual and automatic control) and the scheduling of discrete capacitors and reactors.
- Availability of transmission and distribution system discrete reactive plant as per section 4.4.3.2.
- Following the critical contingency the incremental MW demand (either due to increased system losses or generation imbalance) is supplied remote from the zone of interest such that the weakened transmission system is further stressed.
- Transmission plant only changes state between the pre and post-contingent system conditions if automatic controls are enabled.
- The on-load-tap-changer (OLTC) of the generator step-up transformers and several 275/132/110kV bus tie transformers are normally operated in manual control and as such their tap positions do not change following the contingency.
- All discrete reactive devices connected to the 330kV, 275kV, 132kV and 110kV network can change state automatically if the voltage moves outside the normal voltage range. This plant switches within 5 to 15 seconds following the voltage threshold being breached (therefore before any OLTC action). Post-contingent switching of discrete reactive devices to restore satisfactory voltage levels can occur. However, the appropriateness of this assumption is assessed on a case-by-case basis dependent upon:
    - Number of discrete devices required to be switched;
    - Likely failure mode of the system (i.e. speed of the voltage collapse); and
    - Load at risk.
- On-line generators can provide reactive power support up to levels defined by their respective "performance Standard" (assume "tram track") or reactive power ancillary service agreement (whichever is the greater).
- If the MVAr margin is to be assessed at a bus where there already exists a Static Var Compensator (SVC) then:
    - The MVAr margin is the MVAr-distance between the Q-maximum of the SVC and the MVAr output of the SVC at the knee point if the post-contingent solution is on a positive slope; or
    - The MVAr margin is the MVAr-distance between the Q-maximum of the SVC and the MVAr output of the SVC at the post-contingent operating point if the post contingent solution is on the negative slope.