Powerlink Revenue Reset

CHC Review of Selected Future Capex Reports and Submissions

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1. AER's Brief to CHC for this Report

For the AER's draft decision it sought the advice of CHC Associates (CHC) in relation to PB's conclusions on a number of proposed capital projects. For some of these projects CHC's advice raised sufficient doubts for the AER to seek further information from Powerlink to justify that its proposal was more efficient than PB's. In particular the draft decision sought further information from Powerlink on the following projects:

- Strathmore to Ross;
- Larcom Creek;
- Double circuit line into Larapinta;
- Woolooga to North Coast double circuit line and transformer.

The AER requests that CHC review the additional information that has been provided on these projects (see below) and advise whether or not CHC considers that Powerlink has adequately demonstrated that the option originally proposed by it is more efficient than that proposed by PB.

In relation to the double circuit line into Larapinta, please advise if you see any similarities between this project and PB's recent conclusions regarding the Halys to Blackwall project.

In providing the AER with your comments CHC should have regard to the following information:

- The AER's draft decision for Powerlink (pages 66-68 and Appendix C);
- CHC's previous advice to us on these projects;
- Powerlink's submission on the AER's draft report (see pages 6-19);
- Submissions received by the AER, in particular submissions from Energex, Ergon, Sun Metals and Townsville Enterprise submissions;
- The Powerlink submission on PB's draft report on its review of Powerlink's supplementary submission (see pages 28 and 29);
- Recent responses from Powerlink to the AER's questions on the above projects;

- Project packs that the AER provided CHC with in November 2006.

2. Structure of the Report

The report first considers some common features of the projects under review: in particular the need to consider not only initial costs, but future costs and consequences that affect overall efficiency.

It then addresses each project in turn. So as to present a complete picture it quotes heavily from the text of the AER's Draft Decision, Powerlink's submission on it, and portions of other submissions. This is done without specific acknowledgement or footnotes to identify the source. In some cases this has been paraphrased for some brevity.

CHC's opinion is then derived for each relevant issue.

It is noted that CHC's opinion has changed in several cases, based on new evidence and consideration of the facts.

In some cases there is an immaterial difference between the efficiency of PB's alternative and that of Powerlink's proposal. It is necessary to bear in mind that all cost estimates have a margin of error. In these cases it is assumed that the AER may use its discretion, and decide in favour of Powerlink.

3. Common features of reviewed projects

In any transmission network in which power transfers are predicted to grow over time, network investment decisions must assess the relative merits of different strengths and costs of augmentation. In particular is it more efficient to build a low capital cost, but low capability and high operating cost augmentation, or to anticipate future growth by building a higher cost, higher capability and lower operating cost augmentation that will satisfy transfer requirements for more years. Key elements of the decision are:

- The rate of expected growth in the power transfer requirement;
- The estimated capital costs of the two alternatives;
- The longevity of the alternatives before the next stage of augmentation will be required ;
- The capital costs of the next stage of development in each alternative;
- Differential costs associated with the operation of the two alternatives;
- The appropriate discount rate for investment decisions; and
- Environmental considerations.

Powerlink has categorised this as the balance between short term and long term solutions. The projects that are the subject of this report are examples of where the AER's consultants, PB has questioned the scope of works proposed by Powerlink for augmentations, and has suggested that lower capital cost, lower capability augmentations would be more efficient.

Powerlink has prepared assessments of the relative efficiency of its own options compared with that of PB. The purpose of this report is to assess the relative analyses.

4. Strathmore to Ross 275 kV double circuit line (CP.01512/A)

4.1 AER's assessment of project scope in its Draft Determination

This project has a cost of $138 million and a probability of 28 per cent of proceeding during the next regulatory period. The timing for commissioning of the project is October 2010 under medium growth scenarios and October 2009 under high growth scenarios.

The project involves the construction of approximately 190 kilometres of 275 kV double circuit transmission line from Strathmore to Ross (double circuit twin sulphur conductors), substation works at either end of the line and five new 275 kV circuit breakers. The project has undergone the regulatory test.

PB stated that:

- the need for the project is driven by Powerlink's mandated reliability obligations to supply demand under N–G–1 conditions in the Ross and Far North zones

- generation in this area is subject to considerable uncertainty due to the age, mix and type of available plant

- the only alternatives considered to the recommended options were the construction of a line at a higher AC voltage or a DC link.

PB raised two issues related to this project:

- The scope of the project.

- The timing (and probability) of the project under the high growth scenarios; and

The AER addressed these as follows:

Scope of the Project

PB considered that the scope of the proposed project was not efficient. It considered that the use of a double circuit tower with a single low capacity circuit, combined with some additional shunt capacitor compensation, would be a more efficient option. It noted that if Powerlink still considered it needed the second circuit, it could be strung on the towers in the 2012–2017 regulatory period during times of low demand.

Based on this and the removal of the high growth scenarios, PB recommended that the probability weighted cost of this project should be reduced by $17 million.

CHC observed that Powerlink had analysed the impact of two alternatives to its recommended option of constructing a double circuit twin sulphur conductor. CHC noted that this analysis indicated that the costs of the two alternatives would exceed the cost of Powerlink's preferred option.

CHC also noted that PB had proposed a different option to those considered by Powerlink, involving twin phosphorous conductors and to string only one circuit initially. CHC considered that the question was whether the savings through the choice of a smaller conductor and deferral of stringing the second circuit would be greater than the calculated increased grid support costs. CHC noted that PB had proposed a capital cost for the first stage (one circuit strung) of $100 million, compared with $138 million for Powerlink's double circuit proposal. Based on an interpolation of Powerlink's figures to account for a larger conductor than that analysed by Powerlink when considering the two alternatives, CHC considered that the differential cost of grid support would probably be less than $20 million, but the cost of the second circuit still needs to be considered. Consequently, CHC considered that the difference would be small, and therefore the prudence of PB's recommended scope change was not clear.

The AER acknowledged CHC's views that the prudence of PB's proposed changes to the scope of the project are unclear. As such, the AER seeks further information from Powerlink that its recommended option is more efficient than that proposed by PB. However, for its draft decision, the AER accepts PB's recommendation. Powerlink advised the AER that this would reduce forecast capex by $18 million.

4.2 New Information Provided by Powerlink on Strathmore – Ross scope

In its submission on the AER's draft report Powerlink advised that it has carried out an approximate, conservative economic comparison of PB's and Powerlink's options. The comparison has been done using NPV analysis consistent with the requirements of the regulatory test and the regulatory framework. This necessarily involves longer term considerations than the initial capital cost.

There are two main factors which impact on the economics of these options. Foremost is the required timing of the second circuit on this route between Strathmore and Ross. In addition, the lower network impedance from using larger conductor and double circuit strung results in lower transmission losses, which will act to reduce energy prices in NQ, and in higher transfer capacity and therefore lower grid support costs.

Timing of the Second Circuit
There are a number of limits which impact on supply into north and far north Queensland – thermal, voltage stability and transient stability. The thermal limitation can be addressed for a considerable time by constructing a single 275 kV circuit between Strathmore and Ross substations. However, the maximum secure power transfer into north Queensland will then be determined by transient instability and voltage collapse.

In scenarios with no new generation plant in north Queensland in the required timeframe, these voltage and transient stability limitations would necessitate a second new circuit being strung (or individually switched if a double circuit was constructed initially) between Strathmore and Ross prior to summer 2017/18. Based on PB's proposal of constructing a double circuit line with one circuit strung, stringing of the second circuit during low load periods would need to occur one year earlier in 2016/17.

Grid support costs

The costs of grid support for supply into north Queensland are dependent on the transfer capability which in turn is dependent on the strength of the transmission system between the generation centres of central and north Queensland. The transfer limit for PB's option will be lower than the limit for Powerlink's proposal. The lower the transfer capability, the higher the grid support costs will be to ensure that NEMMCO maintains the north Queensland power system in a secure state.

Powerlink had previously calculated the relative costs of grid support for options involving the use of single circuit and also a double circuit paralleled single paw paw conductor transmission line. The transfer capability reduction was assessed as 50 MW and 35 MW respectively.

The one circuit strung twin phosphorous option recommended by PB would have an impact somewhere between these two values[1]. Powerlink has therefore conservatively used the grid support difference costs previously calculated for the double circuit paralleled single paw paw transmission line (35 MW) in the economic comparison of options.

Under PB's recommended option, the long term network configuration cannot be the same as Powerlink's proposal. The smaller conductor used in the PB option has an ongoing impact of lowering the transfer limit and hence increasing grid support costs. In addition, transmission losses will be higher with the smaller conductor into the future. These cost differences which occur beyond 2016/17 have not been captured by this economic analysis. This understates the long term cost of the PB option.

Economic analysis
Economic analysis for the period to 2016/17 for the Powerlink and PB options, including the relative increase in grid support costs and the cost of differential losses shows an NPV for the Powerlink Option of $128.1M and for the PB Option of $132.6M at 7% discount rate.

The Powerlink option provides a lower NPV cost, even when the higher costs of the PB option beyond 2016 are ignored.

Powerlink said that it has also considered the possible impact of a generator locating in NQ prior to 2016/17, the date by which further augmentation between Strathmore and Ross is required (i.e. string the second twin phosphorus circuit - PB's option or individually switch the twin sulphur circuits – Powerlink's option). Additional generation in NQ would defer the need for the second stage augmentation between Strathmore and Ross. Economic comparison of the options with additional generation in NQ also demonstrates that the Powerlink option provides a lower NPV cost, through lower losses and reduced grid support. The comparison is: an NPV for the Powerlink option of $127.5 million and for PB's option of $128.6 million over 15 years at 7% discount.

Powerlink advised that PB's smaller conductor has ongoing impacts of a lower transfer limit (and hence higher grid support costs), and ongoing higher transmission losses. These ongoing cost differences, after the 15 year period, have not been captured in the above economic analysis.

Powerlink said that to be consistent with the NEM Objective and the regulatory framework, the AER should reject PB's recommendation and reinstate Powerlink's proposed project scope in the Final Decision.

[1] CHC considers that the transfer reduction calculated for single circuit would have been a better assumption because the reactances of twin sulphur and twin phosphorous conductor lines are similar. This confirms the conservatism of the assumption.

In Powerlink's Supplementary Application the timing of this project is advanced by one year for the high and medium economic growth scenarios.

4.3 Other Submissions on Strathmore – Ross project scope

Ergon Energy said that PB has dismissed Powerlink's economic studies to use double circuit high capacity lines without any justification. It does not agree with the reductions proposed by PB for this project due to the adverse impact any such reductions could have to the security of supply to its customers in the area.

Townsville Enterprise engaged ROAM Consulting to provide a report on this project, and this was attached to their submission. ROAM identified a number of adverse impacts to electricity supply if the Powerlink proposal for a double circuit line from Strathmore to Ross is not approved. These are:

- Inability to supply potential expanded industrial load development at market competitive prices due to transmission capacity limitations
- Higher transmission losses at all times but particularly peak times, even for medium growth conditions
- Adverse loss factors leading to higher energy prices for customers, even for medium growth conditions
- Reduced ability to attract major generators to North Queensland owing to lack of transmission capacity

ROAM said that new industrial load cannot be attracted to North Queensland owing to the delivered electricity price to major consumers being about 25% higher than that in Central Queensland. This is solely due to transmission factors since the wholesale price of electricity, as generated, is the same throughout the state. The 25% increase is split approximately equally between higher TUOS charges and higher marginal loss factors. While consumers in North Queensland will have to pay additional TUOS for a larger line, this should be more than offset by reductions in energy costs due to marginal loss factors.

ROAM modelled load growth above the level that would apply when the line is commissioned, and showed that the effect would increase with time. It estimated the additional costs that would apply if a generator was to be established in the area to supply the extra losses, and calculated the value of the differential losses at market rates in comparison with the capital savings that would apply if the smaller conductor was used in the one circuit strung configuration proposed by PB. Their calculations showed that the gap between the two alternatives is narrowed if the cost of losses is considered[2].

ROAM also estimated the differential value of the change in marginal loss factors that would be experienced by customers and generators in NQ at around 2% initially. It said that for the estimated energy sales in NQ of 5539GWh in 2011/12 at a typical energy market spot or contract price of $35/MWh, the 2% additional cost of the PB option represents $3.88million in increased

[2] ROAM did this calculation on the basis of the initial one circuit strung configuration of the line, and did not account for the effect of stringing the second circuit or the cost of these works.

(energy) charges. On the other hand, generators in North Queensland will receive 2% loss on total production volume of about 2000GWh, or a reduction of $1.4 million/annum. The net market benefit to North Queensland (Far North plus Ross zones) is therefore $2.48million.

ROAM also gave its view of the effect of marginal loss factors in attracting generators to North Queensland[3].

4.4 CHC's Opinion on Strathmore – Ross project scope

The Strathmore – Ross project is the third stage of an integrated plan that will duplicate the existing 275 kV network between Broadsound (north of Rockhampton) and Ross (near Townsville). The first two stages involve the construction of twin sulphur conductor double circuit lines from Broadsound to Strathmore via Nebo, and the commissioning of a static var compensator at Strathmore.

The reason for the project is to satisfy Powerlink's reliability obligations, but when completed the project will have the additional benefit for all consumers in NQ of reducing the marginal loss factors that affect the price paid for all energy[4]. The existing lines use single paw paw double circuit construction, and the proposed final configuration will reduce the contribution to the loss factors due to this part of the network by more than half. This outcome of the project was of particular importance to Sun Metals because, as a market customer, it is directly exposed to the market energy cost. This factor was also a prime concern of the Townsville Enterprise submission.

PB assessed that the use of twin sulphur conductors and stringing both circuits of the double circuit line was not efficient, and that the use of twin phosphorous conductors[5] with one circuit strung initially would be more economic, and consequently recommended that the capex allowance for the project be reduced.

Powerlink had already carried out an analysis of an option of using single paw paw conductor with two circuits strung, and submitted an NPV analysis using the network impacts of this configuration, together with the capital costs of PB's recommended (twin phosphorous) option: the latter comprised the initial cost with one circuit strung, plus the cost of stringing the second circuit later. Powerlink claimed that these assumptions about the network impacts are conservative because the electrical characteristics of the paw paw line are intermediate between Powerlink's proposal and PB's recommendation.

CHC has confirmed that Powerlink's analysis is conservative, and has approximately quantified this conservatism as follows:

[3] CHC considers that this assessment is in error, as it is based on an apparent misunderstanding of the impact of marginal loss factors on generation. It is not germane to the considerations and has been ignored.
[4] The Energy price at an entry or exit point is the market clearing price multiplied by the loss factor. There is one market clearing price in the Queensland region, and NQ currently has a high loss factor. All loads pay the adjusted price, and all dispatched generators in Ross and FNQ also receive this higher price.
[5] A phosphorous conductor has a cross-sectional area of about 60% of that of a sulphur conductor, and for the same power transfer has power losses 60% higher. The use of conductors in twin bundles improves the power transfer capacity of the network as determined by voltage stability and transient stability. This effect is very similar for both the twin sulphur and twin phosphorous conductors.

- The value assigned by Powerlink to the differential cost of losses could be multiplied by a factor of 1.4[6] (as determined by the respective line resistances); and

- The value assigned by Powerlink to the differential cost of grid support could be multiplied by a factor of up to 1.8 (as determined by the respective line reactances).

Powerlink's analysis showed an NPV benefit of about $4.4 million for the comparison between PB's and Powerlink's options using the conservative assumptions. This rises to about $10 million with the above adjustments. However CHC acknowledges that the amount of grid support implied in this adjustment may not be available, and instead the next stage of development may need to be advanced. This figure is quoted to quantify the possible extent of the conservatism.

CHC advises that upon the completion of the stringing of the second circuit in PB's option there would be an ongoing difference in the cost of losses over this section that would never be eliminated, reflecting the 60% higher resistance of the conductors. This would result in a permanent disadvantage to NQ customers through the higher loss factor, and this would also increase the difference in NPV. However the grid support cost differential would be removed at this time, because twin conductors of either size have a similar effect on both voltage stability and transient stability.

CHC confirms that when the costs of additional losses and grid support and the extra costs of stringing a second circuit later are taken into consideration PB's option is considerably less efficient than that proposed by Powerlink, and therefore concludes that the capex allowance determined by the AER should reinstate Powerlink's proposal for the scope of this project.

4.5 AER's assessment of timing of Strathmore - Ross in Draft Determination

PB was not satisfied that the project was needed under any of the high growth scenarios on the basis that it was assumed by Powerlink (under its probabilistic methodology) that a generator would commence operating in this area in the following year, removing any further benefits of the line until the next regulatory period. It did not consider that it was prudent or efficient for such a large project to be constructed to avoid one year of potential and marginal (approximately 107 per cent) overloads. PB indicated that should the high growth scenario be realised Powerlink could negotiate with one of its connected parties for a temporary lesser supply standard, implement a control scheme or consider various small scale demand side responses. On this basis, PB recommended that the probability of the line being needed in the next regulatory period be reduced from 28.1 per cent to 21.8 per cent because of the removal of the high growth scenarios.

CHC supported PB's recommendation that the line should not be constructed in the next regulatory period for those high growth scenarios in which sufficient generation would be installed in the following year, thus relieving the potential marginal overloads.

The AER accepted PB's recommendation on the removal of the probability weighted expenditure associated with the high demand growth scenarios. The AER notes that it is efficient to defer a

[6] In the ROAM Consulting attachment to the Townsville Enterprise submission the differential cost of losses was estimated at $1.52 million pa. The basis of this costing was different, comprising the capital cost of generating plant needed to supply the loss demand plus loss energy costed at marginal price. Powerlink's estimate was $0.7 million pa, based on typical market prices. Powerlink's estimate rises to $0.98 million pa when multiplied by 1.4. Powerlink's estimate may still be conservative.

major augmentation if a new generator is expected to be operational in the year following a marginal potential overload. If the overload occurred, Powerlink could still meet its obligations under its Transmission Authority by negotiating an agreement with connected parties to provide lesser supply.

4.6 New Information provided by Powerlink on timing of Strathmore-Ross

The basis for this recommendation raises three issues which are discussed in turn:

1. The potential network violation, which quantifies the required level of DSM;

2. The negotiation of a lesser supply standard with a connected customer; and

3. The timing of the new generator in north Queensland.

Potential Network Violation and required DSM
In the four high economic growth scenarios, the augmentation was proposed prior to the 2009/10 summer. Under these scenarios PB considered the augmentation was being commissioned to alleviate only a potential “marginal” 7% overload during the 2009/10 summer. Powerlink submitted that 7% overload has been summarised from more detailed studies and does not accurately represent the potential risk to Powerlink’s plant, or the amount of DSM that Powerlink would need to contract for over the 2009/10 summer period in order to achieve a deferral.

The generating plant in north Queensland is characterised by energy limitations, and thus, the range in potential operable capacity from the north Queensland generators over the summer months is large. As a result, it is not possible to assess the adequacy of the transmission system, to meet mandated reliability of supply obligations, against a single generation dispatch. Instead, to identify any emerging reliability limitations in north and far north Queensland, Powerlink assesses the combined transmission and generation capacity across a number of different dispatch patterns. The 7% overload referred to by PB and the AER represents an average of the potential overload measured across six different generation and demand combinations.

The different generation and demand combinations were developed by an independent consultant (Energy Market Services Pty Ltd) who considered this approach was necessary given the age, mix and type of generation plant in north Queensland. Energy Market Services recommended that the adequacy of the transmission system be assessed across six generation and demand combinations, and that weighting be given to the number of cases approaching or exceeding the limitation. That is, the cumulative risk across all six cases is important.

Under the four relevant high economic growth scenarios, the network limitation was forecast to be exceeded over the 2009/10 summer in all six generation and demand combinations. The average network violation was 7%. Based on 7% overload, approximately 40MW of demand response would need to be contracted (“firm”) for Powerlink to meet its mandated reliability of supply obligations. However, the maximum forecast violation over the 2009/10 summer is 19%, requiring in excess of 110 MW of demand response which must be located in or north of Townsville. Powerlink says that this is larger than any single load in this area[7].

[7] Sun Metals quoted its maximum demand as 134MW. According to the Final Report (regulatory test) an unknown portion of this load was to be contracted as a DSM contribution for Grid Support in summer 2007/08, ahead of completion of the 275 kV line from Nebo to Strathmore.

Given Powerlink's mandated reliability obligations and the significant risks which emanate from non-compliance, it is inappropriate to rely on the average overload because there is a credible, much larger overload.

A lesser standard of supply to connected customers
In order to assess whether a lesser standard of supply to connected customers is likely to be acceptable in any given circumstance, the characteristics of that lesser standard must first be determined.

In addition to thermal limitations, the maximum secure power transfer into north Queensland is limited by transient and voltage instability. These limiting criteria arise due to the length of the transmission system. The interaction between these limitations is complex and depending on the generation dispatch any one of them may determine the limit. The occurrence of limitations from voltage and transient instability means that demand side response to alleviate forecast violations must occur pre-contingent, i.e. to be effective the demand reduction must occur prior to a violation actually occurring. This increases the incidence of the demand response because it must reduce demand in case a contingency occurs rather than only when a contingency actually occurs.

Those matters which provide a substantial weight of evidence against a suitable demand side response being available in south east Queensland are also applicable to supply into north and far north Queensland. In addition, the requirement for pre-contingent demand reductions, which increase its use dramatically, and the large size of the reduction (112MW) make demand response in north and far north Queensland even less likely to be feasible.

Powerlink advised that in a consultation associated with reinforcement of supply to North and Far North Queensland, Powerlink received 15 submissions of which 9 contained potential non-network solutions. As part of its evaluation and assessment process, Powerlink issued all potential non-network solution providers with an information paper outlining the timeframe and criteria for assessment of their solutions. The evaluation of options resulted in contracts for provision of grid support from two non-network solution providers (both generators).

Powerlink has conducted several regulatory tests and associated consultations in relation to supply into north and far north Queensland, including one as recently as 2006. In every case no new suitable demand response has been identified. For example, Powerlink approached the Cairns Chamber of Commerce when planning augmentations in the Cairns area. The feedback was that it would not be practical due to the already flat load curve, the need for pre-contingent DSM due to the predominantly stability-based limits on transmission capability, and the high load growth.

Timing of the New Generator in North Queensland
A distinguishing characteristic of the four relevant high growth scenarios is that those scenarios assume a new generator is commissioned in north Queensland in 2010/11. As a result, the network violation does not continue to grow as operation of the generator removes the violation in 2010/11 and it does not reappear until beyond the next regulatory period. PB and the AER cited the planting of this generator as pivotal to the justification for recommending this reliability augmentation was not required in the coming regulatory period.

As noted in Powerlink's Supplementary Revenue Proposal (December 2006), there has been a material change in the outlook for new generation in North Queensland, with the probability of generation from the PNG pipeline in the required timeframe now being zero. Powerlink considers there is also no likelihood of a generator based on CSM gas emerging in the required timeframe. To meet the reliability obligation in 2009/10, Powerlink would need to commit to construct the network augmentation by October 2007. The capacity of the only developed CSM production (Moranbah) is almost all committed to the existing Townsville power station, and it is highly unlikely that additional CSM can be bought to "bankable" status before a firm decision on network augmentation must be made.

Under these circumstances, it is highly speculative to rely upon a generator appearing in the previously-mooted timeframe. Powerlink has no option (under its Transmission Authority) other than commit to the construction of the network augmentation so as to maintain reliability standards.

Overall
Powerlink considers that the evidence presented demonstrates that no new DSM could be cost effectively contracted to meet its mandated reliability of supply obligations in 2009/10. History and the sheer volume of pre-contingent demand response required, rule this out as a viable option under these scenarios. As a result, Powerlink does not consider it appropriate for the AER to reduce Powerlink's capital expenditure allowance to account for such a deferral in the high growth scenarios. In addition, Powerlink notes that the current regulatory framework with an ex-ante allowance for capital expenditure naturally incentivises Powerlink to seek non-network solutions if they can be implemented at lower cost than the revenue associated with the capital expenditure. Further, the recent change in outlook for new generation in north Queensland makes it highly speculative to rely on. It should be noted that even with the Strathmore – Ross augmentation in these four high growth scenarios the cumulative probability of the augmentation is still less than 50%. Therefore, in its Final Decision the AER should reverse its decision in relation to the deferment of the Strathmore – Ross project in the high growth scenarios.

4.7 Other submissions on timing of Strathmore Ross

Ergon Energy submitted that it would not be able to agree to such a reduction in supply standard because it would directly affect its customers. It also said that it is also unlikely that any "small scale demand side responses" would be successful in the near term as Ergon Energy has already implemented a load management scheme in the area of interest. Ergon agrees that there is little ability to achieve additional demand side response to contingencies in the area.

Sun Metals stated that it is a very large direct market customer located at Townsville and that it is directly affected by this project. It notes that the Strathmore – Ross project is the third stage of a project that will result in construction of a 275 kV line between Broadsound and Ross (near Townsville), via Nebo and Strathmore.

Sun Metals says that it supports Powerlink's development on the basis that the forecast loads are likely to underestimate growth in NQ and that the reduced losses paid by NQ will offset the increased network costs.

Sun Metals outlined its own potential expansion plans, and said that it is aware of numerous other opportunities for industrial development in the Townsville area.

It also said that the fundamental realignment of marginal loss factors in NQ that will result from the Powerlink developments will counter the increased network charges to deliver overall market benefits to existing customers. The market benefits will grow because the reduced MLFs will work to increase the industrial load growth in the area, and this will tend to reduce the per-unit costs of network charges and hence realign the delivery costs of electricity for NQ. It therefore submits that the market benefits for the Powerlink stage 3 development will outweigh the short term higher network charges that will be imposed on current customers.

4.8 CHC's Opinion on Strathmore-Ross Timing

Powerlink says that to meet the reliability obligation in 2009/10, it would need to commit to construct the network augmentation by October 2007. It states that it has no option under its Transmission Authority other than to address this issue by building the line. However, in October 2007 it will actually be making decisions on the basis of the next (2007 APR) medium growth forecast: not the 2006 APR high growth forecast. Hence this is a theoretical argument that has no impact on the probabilistic planning methodology.

Powerlink has stated that it is now unlikely that a generator will be commissioned in the following year to relieve the overload that is driving this development. This is really arguing that the generator scenarios provided by ROAM that Powerlink has used as the basis of the probabilistic approach are flawed, even after the PNG Gas scenarios are removed. It is the basis of the probabilistic method that all the scenarios must be treated as "real", and then weighted according to probability. Hence this argument is also seen by CHC as irrelevant in the context of the probabilistic methodology.

However it is relevant that the decision to commit to the project will be made in the context of the best assumptions about generation patterns at the time, and would not be delayed on the basis of an uncertain generation development. It means that the respective lead times for generating plants and transmission lines need to be considered, and that there will always be a possibility that the value of a network investment will be negated by a subsequent power station. This may not be efficient, but it is beyond the control of a TNSP.

Powerlink has presented evidence that the amount of overload (7%) that was assessed by PB in scenario 33 as being "marginal" is the average of six sub-scenarios of demand and generation dispatch, and that the maximum overload is 19% or 112 MW. CHC notes that the network limitation was breached in all six sub-scenarios, but that the overload was less than 7% in all but one sub-scenario, and that the sub-scenario with 19% overload is therefore an outlying result.

Energy Market Services[8] recommended criteria for assessment of the need to augment because of a reliability of supply limitation. It recommended that a decision should be made when the cumulative risk would be more than what would be accepted as "good industry practice". It proposed three criteria for supply capability:

1. Supply capability should be considered inadequate when the maximum supply capability is less than the maximum identified electricity demand for that scenario;

2. When the difference between the maximum demand and the minimum identified supply capability approaches the size of the largest generating set there is a clear additional risk that should not be countenanced (i.e. failure to supply with all operable units in service)

3. Weighting should be given to the number of scenarios approaching or exceeding the above criteria i.e. the cumulative risk across all scenarios is important.

[8] EMS is the consultant that advised Powerlink in relation to the planning criterion for this region

Powerlink has argued that if it is to address this issue through demand side measures then a demand reduction of 110 MW would have to be achieved to address the 19% overload. However an interpretation of criterion 3 is that if Powerlink was to achieve 7% demand reduction (40MW) then it would eliminate 5 of the 6 overload conditions, and this could satisfy the criteria. Therefore it is considered that PB's interpretation of the DSM requirement was reasonable.

CHC notes that Powerlink has applied Grid Support on a pre-contingent basis, consistent with the requirement being determined by voltage or transient stability considerations, rather than line thermal rating. While it would arguably be unnecessary to achieve an additional 70MW reduction (110-40MW) it is considered that, in any case, this would only have to be applied if the particular power transfer scenario that caused the 19% overload was to occur in practice. This sub-scenario would involve a particular generation and load pattern that would be readily identifiable.

Both Powerlink and Ergon Energy have made a case for there being little potential for additional DSM in the area, given that Ergon has already implemented a load management scheme.

However, CHC notes that Powerlink's Final Report[9] that presented the case for the staged development between Broadsound and Ross included the use of Grid Support over the summer of 2007/08, ahead of the planned completion of the Nebo to Strathmore stage. Contracts were said to be in place between Powerlink and Enertrade[10], Sun Metals[11] and CSR[12]. According to the Report:

> The network support agreements provide for operation of the generating plant to address reliability of supply requirements at times when the plant would not otherwise be operating in the NEM. Under the agreements Powerlink can request the generators to operate when required for transmission purposes.

In the Final Report Powerlink estimated the cost of these services at \$15.7 million to \$42.7 million for 2007/2008. CHC assumes that provision was made for these services because Powerlink did not think it could complete the Nebo to Strathmore line section before summer 2007/2008[13]. Thus the use of the services was not because they are a more economic alternative than earlier completion of the line.

Powerlink included "modelled projects" in the preferred option, comprising ongoing use of the above arrangements, and noted that their value would be reviewed as commitments were made to the two subsequent stages. The cost listed for 2009/2010 is \$14.7 million to \$19.9 million.

The capital cost of the Strathmore to Ross line is about \$125 million, and assuming a 9% discount rate the annual cost of the line is \$11.25 million, which is less than the estimated cost of the Grid Support services that would otherwise be required. Thus the decision can be made on an economic basis.

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[9] Powerlink Queensland Final Report, Addressing reliability of supply requirements in North and Far North Queensland, 2007-2010, 29 Nov 2005 p26

[10] Enertrade is the market trader of several power stations in the North Queensland area including Collinsville, Townsville and Mt Stuart power stations.

[11] Sun Metals owns and operates a zinc refinery in Townsville and can provide DSM services (load reduction)

[12] CSR owns and operates a bagasse-fired cogeneration plant at Pioneer Sugar Mill near Ayr. Network support would be provided outside the crushing season, with maximum support capability limited to around 30MW.

[13] The Broadsound to Nebo line and an SVC at Strathmore are timed for completion "late 2007"

Ergon makes the point that it (i.e. the Ergon network business) cannot agree to a reduction in supply standards. CHC notes that Ergon, as well as Powerlink, has statutory supply obligations. This means that the theoretical possibility of a negotiated reduction with the Ergon network business is unlikely to be applied. Any reduction in standard would therefore have to be a negotiated with retail customers, possibly through one or more of the retailers that operate in the area. There would have to be a mechanism for achievement and verification of the negotiated demand reduction in a manner that did not affect other customers. If the reduction is required on a pre-contingent basis because of the nature of the network limitation (voltage stability or transient stability) such an arrangement is very unlikely to be achieved. CHC's assessment is that this framework makes it difficult for Powerlink or Ergon to negotiate an additional short-term arrangement to relieve a potential major overload, and that this possibility should be dismissed.

In CHC's opinion the AER's decision about including a (probability weighted) capex allowance for the Strathmore to Ross project in high growth scenarios should be based on an assessment of how Powerlink should efficiently address its reliability obligations in 2009/10, without regard for the potential for generation the following year. CHC considers that a reasonable interpretation of the planning criterion is that Powerlink would have to secure 40MW of pre-contingent Grid support services and/or DSM to meet its obligations in 2009/10. It appears that these would be available, but at a higher cost than completion of the line.

If the AER was to disallow this capex, then it should also anticipate that there would be additional Grid support costs that would almost certainly exceed the annualized cost of the line. In CHC's opinion the probability-weighted capex should therefore include the construction of this line in 2009/10 in the relevant high growth scenarios.

5. Larcom Creek 275/132 kV substation establishment (CP.01958)

5.1 AER's assessment of Larcom Creek in the Draft Determination

This project has an estimated cost of $48 million, a probability of 89 percent, and it is timed for July 2009.

The project involves the construction of a new substation designed for full breaker and half layout across eight switchbays with eight 275 kV circuit breakers and two 275/132 kV (375 MVA) transformers. It also includes the establishment of a remote 132 kV switchyard site via 7.7 kilometres of 275 kV double circuit transmission line (initially operated at 132 kV). The project has undergone the regulatory test.

PB stated that:

- the need for the project was driven by Powerlink's mandated reliability obligations to supply all demand under N–1 transmission conditions within the Gladstone zone;

- it was satisfied with the need for the project and that the general timing of the project had been triggered by the commitment of a new coal terminal at Wiggins Island. However, PB was unclear why the project was specifically required in July 2009;

- it was satisfied that Powerlink had considered a number of network and non-network alternatives to the development of Larcom Creek and that none of these options provided the same level of flexibility and strategic benefits.

Powerlink's design of the substation takes into account the expected industrial developments in the Gladstone State Development Area (GSDA). Powerlink stated that given the size of the GSDA industrial precinct, load in the Gladstone area could increase by as much as 2500 MW above the forecast demand levels over the next 15 to 20 years. To accommodate this potential growth, Powerlink has provided for three key strategic aspects in its design of the substation. Powerlink is:

- developing a 7.7 kilometres 275 kV transmission line to the remote 132 kV switchyard but operating it at 132 kV until it builds another 132 kV line when the capacity is required for a 275 kV line;

- building Larcom Creek across eight switch bays to allow for ease of future augmentation when additional 275 kV lines are connected to it;

- installing high capacity 375 MVA transformers at the substation for a radially supplied load that could range from 40 to 200 MW.

PB stated that although each of these strategic decisions reflected good consideration of future requirements, it considered there is a low likelihood of these industrial developments taking place in the next regulatory period and that only some aspects of Powerlink's proposed scope are efficient in the short term. PB recommended an allowance for this project based on:

1. a 132 kV transmission line instead of a 275 kV line;

2. the 275 kV switchyard be developed with only three switchbays and seven circuit breakers;

3. the transformer capacity be reduced from 375 MVA to 200 MVA;

4. the project being deferred by three months.

PB considered that Powerlink could readily accommodate the extension of the 275 kV substation as required when and if the new lines were constructed to Larcom Creek, and that 200 MVA transformers would provide sufficient headroom for local load growth and the connection of some new customers to this new radial network.

Powerlink noted that with 200 MVA transformers, Larcom Creek substation would have a firm capacity of approximately 250 MVA. It stated that while no additional projects (with the exception of Wiggins Island) had been committed, it would seem reasonable, given the size of the GSDA to exceed 250 MVA.

In relation to four aspects of the project that PB commented on, CHC provided the following advice:

- Timing of project for October rather than July—while generally October is chosen for projects that are driven by summer load growth, projects driven by spot industrial developments are normally targeted for the agreed commissioning date of the load.

- Choice of 275 kV construction for the line to the remote switchyard—Powerlink appears to have given no explanation as to how the line would be used at 275 kV, consequently PB's recommendation is reasonable.

- That the 275 kV switchyard be developed with only three switchbays—due to a number of factors (e.g. site levelling, fencing and need to build the additional bays with the substation live) the reductions thought possible by PB may not be achievable.

- Transformer capacity be reduced to 200 MVA rather than 375 MVA—changing transformers to a larger design is not a trivial exercise, as foundations are built specifically for each design and auxiliary plant and cabling would also need to be changed. Powerlink indicated that the larger size should be used if it will be needed in 12 years and this appears reasonable. The critical total demand to require this larger capacity would be only 200 MW and this seems very likely to be exceeded. The choice of 375 MVA transformers therefore appears prudent.

Overall, CHC considered that in principle the points made by PB were valid and that some reduction was warranted.

The AER has considered comments by PB, Powerlink and CHC. It acknowledges that the larger transformers appear to be prudent and there are difficulties associated with building further switchbays in a live substation environment. The AER seeks further information from Powerlink on its choice of 275 kV construction for the line to the remote switchyard and what date the new coal terminal at Wiggins Island is planned to begin operations. However, for its draft decision the AER accepts PB's recommendation that an allowance for this project be based on: a 132 kV line to the remote switchyard; that the 275 kV switchyard be based on only three switchbays and seven circuit breakers; and that the project be deferred until October 2009. Powerlink advised the AER that this would reduce forecast capex by $0.4 million.

5.2 New Information provided by Powerlink on Larcom Creek

Powerlink advised that it had considered the option of developing Larcom Creek substation over 3 switchbays but this was not discussed in detail during PB's review. In determining the substation layout Powerlink considered the potential load growth in the GSDA and the impact this would have on the future development at Larcom Creek substation.

If a smaller initial substation development is implemented the cost of the required expansion is higher when it is required. The exact date at which expansion is required is uncertain. Some of these cost components include:

- Re-establishment of a civil earthworks contractor;

- Removal of the original line entry diversion (Bouldercombe – Larcom Creek 275 kV line); and

- Substation panel modifications for the original line bay adjusted to suit a new configuration.

When these additional costs of later expansion are taken into account the break even time between the Powerlink and PB options is approximately 5 years. Given the potential load developments anticipated in the GSDA Powerlink considers it is both prudent and efficient to construct the larger substation layout initially thereby also avoiding outages for further work.

In regard to transformer size Powerlink advised that it is in regular formal and informal discussions with proponents of large projects within the GSDA that could potentially become large future electricity users. No large projects have fully committed at this stage (in addition to Wiggins Island) and there is uncertainty regarding the location, size and timing of any additional load. However, the size of the GSDA area suggests enormous potential for load growth in the area.

In its Submission Powerlink advised that with only 200 MVA transformers Larcom Creek would have a firm capability of approximately 250 MVA. Ignoring the cost of differential losses, approximately 12 years is the breakpoint beyond which the smaller transformers are more economical. This was based on the differential capital cost between 2x200MVA and 1x375MVA transformers (noting that the emergency cyclic ratings of these alternatives are approximately equivalent at 450 – 500MVA).

In response to additional questions put to it by the AER Powerlink advised that NPV analysis related to the selection of the transformer rating had been undertaken subsequently. Powerlink now says that if the cost of switching a future third 200MVA transformer is also taken into account the breakeven timing would be much longer than 12 years. These switching costs would include a third 275kV 1½ CB diameter (2 CBs) ~ $2.4m and establishment of a 132kV "U" bus at Larcom Creek for 3 transformers (1 additional CB required), 2 feeder bays and bus coupler CB ~ $3.9m.

While all of these costs are not necessarily attributable solely to the third transformer Powerlink considered that at least the 275kV switching costs should be attributed to this additional transformer. Including the 275kV switching cost, the NPV analysis shows that if a third 200MVA transformer is required within 20 years then it is more efficient to install the larger 375MVA transformers initially.

In its submission Powerlink did not address the reasons for not connecting to the remote substation using a 132 kV transmission line designed for 132 kV operation. However, in answer to a question from the AER, Powerlink repeated its advice that the only spare easement in the area is earmarked for 275kV operation. Powerlink is not confident that a new easement for a 132kV line could be secured to preserve the required commissioning date. In the longer term this line will be required to operate at 275kV to overcome thermal limitations between Bouldercombe and Gladstone. Depending on the generation development scenario this could be as early as 2013/14.

5.3 Other submissions on the Larcom Creek Project

Ergon Energy supports the strategic initiatives proposed by Powerlink to supply this very important industrial development and rejects any proposed scaling back. It says that the Gladstone industrial area requires supply security commensurate with the types of industry operating in that area, and needs to have appropriate capacity to support new industrial development in challenging time frames and cannot afford sustained lowering of the level of security of supply in order to perform network upgrades. Ergon says that the Powerlink proposal addresses these requirements.

5.4 CHC's Opinion on Larcom Creek

In respect of the Larcom Creek substation construction scope CHC notes that the break-even time for the second stage development after the first stage (requiring additional switchbays and transmission line re-termination) is 5 years if the discount rate is 7%, or 4 years if a discount rate of 9% is used. Powerlink has not produced evidence that the second stage would be required within this period, but has relied upon the statement that "given the potential load developments anticipated in the GSDA Powerlink considers it is both prudent and efficient to construct the larger substation layout initially thereby also avoiding outages for further work".

Based on this information the case for allowing the higher initial expenditure of $2.28 million is slightly weaker than when the draft decision was made. However if the second stage works are not required for 10 years the difference in NPV is only $0.3 million at 9% discount or $0.1 million at 7% discount. The AER may consider that this NPV difference is immaterial as it is smaller than the accuracy of the cost estimations. In this case the AER could make allowance for Powerlink to develop the substation in its preferred manner to make the next stage work easier and safer. It is noted that Ergon's reference to lowering of the level of security of supply in order to perform network upgrades would be applicable here.

In respect of the transformer size Powerlink provided new NPV analysis that compares two 375MVA transformers with two 200MVA transformers initially and a third when required by load growth. The break-even time for this augmentation is around 20 years, and it is certain that an additional transformer would be required in this time if the smaller transformers were installed initially. Therefore the decision to install 375 MVA transformers is prudent and efficient in the long-term, thus confirming the AER's draft decision to retain this size.

In respect of the transmission line the reason advanced by Powerlink to support 275kV construction is that the only available easement is reserved for 275kV, and there would need to be a new easement purchased for a 132kV line. There is some doubt about whether this could be done in the time. Powerlink's plan is to convert the line to 275kV operation at some future time (possibly as early as 2013/14), after which the use of the 132kV line would be uncertain: it is assumed that it could be redundant.

CHC's opinion is that a sufficient case for making an allowance for 275kV construction has not been made on economic or efficiency grounds. However, CHC considers that it is good industry practice, (and good corporate citizenship) to only alienate land and build lines that have an ongoing application in the longer term strategic plan for the network. This is the case for a 275kV line on the existing easement, but not for a new 132 kV line. However if the AER decides to make allowance for 132kV construction the cost of a new easement should be included, as it would not be practical to maintain secure supply while totally dismantling a 132kV line to build a 275kV line.

6. 275 kV double circuit line into Larapinta (CP.01771/B)

6.1 AER's assessment in the Draft Determination

This project has an estimated cost of $88 million and a 76 per cent probability of proceeding during the next regulatory period. The timing for commissioning of the project is September 2008 under high growth scenarios and September 2012 under medium growth scenarios.

The project involves the construction of high capacity 275 kV double circuit line into Larapinta, which includes some underground cable. Both high capacity lines will be utilised at 275 kV operation. Substation works will be required at either end to allow the new lines to be switched, monitored and protected from faults. Three 275 kV and two 110 kV circuit breakers are also required.

Based on its review of this project PB stated that:

- it was generally satisfied with the need of the project, given the multiple contingencies leading to constraints and the nature of load growth in the south Brisbane area, even under the medium growth scenario

- Powerlink had considered a number of alternatives to the development of high capacity double circuit lines into Larapinta, including uprating and restringing the existing lines and options to lay the second underground cables at a later date

- detailed NPV calculations for a number of alternatives had been considered given the timing of various anticipated projects and these supported the preferred option.

In general, PB considered that the scope of works and the costs associated with this project represented an effective and efficient approach to the forthcoming reliability constraints. However, it noted that Powerlink had previously been able to defer this project via the transfer of load on the distribution network. Given this, and the relatively small potential overload forecast in summer 2011–12 of 2.6 per cent, PB considered that there may be an opportunity to defer the project by a further year by negotiating with one of its connected parties for a temporary lesser supply standard or through small scale demand side responses.

On the basis that the risk to Powerlink of deferring the project by one year would not be significant, PB recommended that the allowance for this project be halved and allocated to the last year of the next regulatory period. PB considered that this single year deferral would have the impact of pushing the majority of the required capex into the 2012–2017 regulatory period. It estimated the impact of its recommendation would be to reduce forecast capex by $33 million.

CHC noted that this project is the result of joint planning and already incorporates a deferral through the assumed transfer of load on the distribution network in the event of a contingency. CHC considered that it was possible that this has exhausted the negotiation option, as Energex also has an obligation to plan for full supply. CHC also considered that the other proposed demand side management option could be particularly difficult and expensive to acquire for just one year due to establishment costs.

The AER accepts that the scope of works and costs associated with this project represent an efficient and effective response to the emerging constraints. It also acknowledges the difficulties raised by CHC in deferring this project, however, it seeks further evidence from Powerlink that it is not able to negotiate with one of its customers for a temporary lesser supply standard and that demand side management is not a viable option. Therefore, for this draft decision, the AER accepts PB's recommendation that the timing of this project should be deferred by one year due to the high cost of this project, its proximity to the end of the next regulatory period and the relatively small potential overload forecast in 2011–12. Powerlink advised the AER that this would reduce forecast capex by $32 million.

6.2 New Information Provided by Powerlink

Powerlink considers PB's basis for the deferment of this project to be speculative and its assessment of the resultant risk to be incorrect. It demonstrates a lack of understanding of Powerlink's mandated reliability of supply obligations.

While PB suggests that Powerlink is able to unilaterally decide to take some "risk" and not plan the development of its network to meet the forecast peak demand, Powerlink contends that simply taking that risk is clearly a violation of Powerlink's mandated reliability obligations.

In determining the timing of this project in the forecast plans, Powerlink had already considered demand reduction opportunities which would defer the need. In its Draft Decision, the AER acknowledged that the project had already been deferred one year through an assumed transfer of load on the distribution network in the event of a contingency.

Contrary to PB's suggestion, Powerlink contends that the risk of non-compliance with a mandated licence requirement is not insignificant. Such non-compliance could lead to insurance cover being voided, and leave directors and officers liable to negligence claims.

Powerlink also does not consider it appropriate that the AER rely on the speculative assumption of a temporary lesser standard of supply being able to be negotiated through DSM to defer this project. Under the medium economic growth scenarios, Powerlink has forecast this project to be commissioned by September 2012. Given this timeframe the project has not undergone a regulatory test or any public consultation. However the project has been the subject of joint planning with Energex, and through that process Energex (the connecting customer) has confirmed that it expects Powerlink to meet the N-1 standard for the forecast peak demand. Based on Powerlink and Energex's experience to date, it is also considered highly unlikely that additional DSM (over and above that already included in the forecasts) will materialise at an economic cost to defer this project.

There is already a high level of DSM implemented within the Queensland load. This DSM includes ripple or time clock control of a range of loads such as hot water, pool filters, dryers and even some air conditioning. These initiatives have been in place for many years. Such load control significantly contributes to Queensland having the highest annual load factor in the NEM, and one of the highest in the world.

It is assumed that this practice will continue to grow into the future as load forecasts assume that the whole load curve increases. As a result, a high level of DSM is already being used to defer network augmentation for as long as practical.

In addition to the existing (and forecast to grow) DSM, Powerlink also publicly requests information on new DSM (along with other forms of grid support or non-network solutions) in the Requests for Information (RFI) document issued as part of the Powerlink regulatory test consultation process. This RFI is an added step that Powerlink voluntarily undertakes prior to preparing the Application Notice required by clause 5.6.6(b) of the NER. The RFI describes the network limitation in some detail and outlines the required characteristics for non-network solutions – e.g. size, location, operating characteristics, extent of commitment and other key contractual requirements.

The RFI is specifically aimed at seeking submissions from potential non-network solution providers. Powerlink also approaches the Queensland retailers, acting as aggregators of DSM solutions and meets with customer groups to discuss whether they would be interested in offering new and additional DSM solutions.

Powerlink advised that this approach has been very successful in identifying potential non-network solutions where they genuinely exist. However, despite many consultations and meetings, limited customer demand reduction arrangements have been available. Most of these have only been suitable for very onerous situations to avoid severe restrictions or prevent cascading failures. Queensland retailers have not offered any interruption rights they have negotiated with customers for deferring network investment: rather such reductions are used to reduce demand during high price periods in the spot market as part of their hedging arrangements.

As part of its review, PB assessed Powerlink’s approach and procedures to the identification, evaluation and procurement of non-network solutions and found them to be appropriate.

The AER also noted that Powerlink is one of the largest purchasers of network support in the NEM and that Powerlink’s existing planning, project approval and regulatory test applications ensure that non-network options are identified and considered appropriately.

The AER also noted that the high growth characteristics of the Queensland power system and its demand profiles do not strongly favour such options, but still considered Powerlink had endeavoured to overcome the technical and commercial complexities with the intent of deferring network augmentation.

Notwithstanding the fact that Powerlink’s procedures are “robust” and “prudent” (by the AER’s and PB’s own volition) and that Powerlink is the largest user of non-network solutions in the NEM, Powerlink has not been able to obtain new DSM solutions to defer network investment, particularly in the high growth south east Queensland area where the Larapinta project is located. Notably, the Larapinta project is in the high growth area of south west Brisbane supplying the planned “western corridor” of the South East Queensland Infrastructure Plan.
Powerlink does not expect that the availability of DSM will change in the foreseeable future for the following reasons:

Residential DSM is already widely used resulting in Queensland having the highest annual load factor in the NEM, and one of the highest in the world. The load forecast already assumes that this DSM grows as the load grows.

- The relatively flat daily demand profile means that any new DSM would need to be available for extended periods over the summer months.
- High load growth in SEQ means that the amount of DSM required must increase significantly each year. With the relatively flat daily load profile the hours of exposure grows very quickly as the DSM required bites deeper into the load duration curve.
- Unless the DSM response is available at the optimal network connection point, the amount required to relieve the limitation is even greater (again further increasing the time of exposure).
- The DSM response must be available at call at the time of actual peak demand (regardless of any lost opportunity costs by the customer).
- Retailers’ preference has been to keep such services for hedging against large pool prices.

With little or no prospect of new generation down stream of the limitation the violation of the network limitation grows continuously. Therefore, DSM does not offer the opportunity to avoid a short term limitation and thus significantly defer the network augmentation. Given the overheads associated with negotiating and implementing suitable DSM arrangements a one year contract is likely to be difficult and expensive to obtain.

Powerlink therefore considers there is a substantial weight of evidence against a suitable and cost effective DSM solution being available to defer the Larapinta project by one year, and that the AER/PB position is both speculative and incorrect in its risk assessment. Given the significant consequences of non-compliance, Powerlink does not consider it appropriate for the AER to use a speculative assumption to reduce its capital expenditure allowance. In addition, Powerlink notes that the current regulatory framework with an ex-ante allowance for capital expenditure naturally incentivises Powerlink to seek non-network solutions if they can be implemented at lower cost than the revenue associated with the capital expenditure.

6.3 Other Submissions on Larapinta project

Energex advised that its previous experience is that large customers, who could logistically offer DSM) expect full N-1 reliability of supply, and have been unwilling to enter into DSM agreements. Energex also said that it understood that Powerlink had conducted public consultations regarding other proposed network augmentations and that no genuine DSM proponent had emerged. It is too early for such consultations to be conducted for this project, which is not forecast to be required until 2011/12.

6.4 CHC's Opinion on Larapinta Project

It should be the responsibility of the TNSP to assess the potential for demand side response for all proposals. It is only practical for the AER to assess whether they have undertaken due process. PB and the AER have recognised that Powerlink has a "robust and prudent" approach to this. As a general statement consultants engaged by the AER for a reset application review are not in a position to assess the possibility of achieving DSM in specific cases. Only if they were so, and if they could point to a specific provider, would it be appropriate to over-ride the assessment of the TNSP.

In this case Powerlink has largely restated the background information that it has provided previously. However in its submission Energex has provided support for Powerlink's assessment of the lack of potential for DSM. This can be given credence because Energex has itself been engaged in these activities in this area.

The suggestion that Powerlink could negotiate a lower level of supply security is strongly contested by Powerlink. Powerlink reiterates that it is not able to unilaterally decide to take some "risk" and not plan the development of its network to meet the forecast peak demand, because this would clearly be a violation of Powerlink's mandated reliability obligations. Contrary to PB's suggestion, Powerlink contends that the risk of non-compliance with a mandated licence requirement is not insignificant. Powerlink says that non-compliance could lead to insurance cover being voided, and leave directors and officers liable to negligence claims.

As CHC advised in respect of Ergon Energy's submission for the Strathmore–Ross line the Energex network business cannot agree to a reduction in supply standards because Energex, as well as Powerlink, has statutory supply obligations that would prevent this. Hence the theoretical possibility that there could be such an agreement between Powerlink and Energex (network) is not likely to be applicable. Any reduction in the "supply standard" would therefore have to be negotiated, not with Energex, but with one or more retail customers, possibly through one or more of the retailers that operate in the area. There would have to be a mechanism for achievement of the negotiated reduction at the time required, and in a manner that did not affect other customers. Such an arrangement is very unlikely to be achieved, particularly in respect of a short term requirement. Set-up costs would be significant.

CHC's opinion is that it is difficult for Powerlink or Energex to realise a demand side response or to negotiate a short-term arrangement to relieve a potential major overload, and that this possibility should be dismissed.

These possibilities were the only reasons advanced by PB for the deferral of this project. Despite the timing of this project for commissioning beyond the next reset it is CHC's opinion that the proposed expenditure within the next reset should be reinstated.

6.5 Similarities to Halys to Blackwall Project

In the case of both the Larapinta project and the Halys to Blackwall project the anticipated overload was very small, and PB's recommendation was that Powerlink should either take a risk or negotiate a lower supply standard. There is a similar consideration for the Strathmore to Ross project, although the potential network overload is larger.

CHC has outlined above its opinion that such assumptions should not be made without evidence that it is achievable. There is strong evidence that it is not achievable in the SEQ area.

In the case of the Halys – Blackwall project the resolution was that the construction sequence should be changed to avoid this situation without compromising security. However this had a cost associated with advancement of an SVC.

In the case of Strathmore to Ross the network solution was assessed as being more efficient than the non-network solution.

There is no known equivalent non-network solution in the case of Larapinta.

In all three cases the proposed resolution recognises Powerlink's reliability obligations.

7. Woolooga to North Coast 275 kV line and transformer (CP.01264/A)

7.1 AER's assessment in the Draft Determination

This project has an estimated cost of $67 million and a probability of 76 per cent. The timing for commissioning of the project is October 2009 under the high growth scenarios and October 2011 under the medium growth scenarios.

The project has been planned jointly with Energex. It involves the construction of approximately 70 kilometres of 275 kV double circuit transmission line from Woolooga to the North Coast to be operated as a single paralleled circuit, with a 275/132 kV transformer directly connected at the

North Coast end of the line. The development also requires one 275 kV circuit breaker at Woolooga and connection to an existing 132 kV switchyard at the North Coast end of the line.

From its review, PB found that:

- the project is related to load growth in the northern area of the Sunshine Coast and loading on Energex's Woolooga–Gympie 132 kV lines;

- Powerlink and Energex had considered four network alternatives, including operating the line at 132 kV and development at 132 kV;

- while the economic NPV analysis could have been presented in a more transparent and detailed manner, the approach taken was reasonable.

PB noted that Powerlink and Energex are proposing to establish 275 kV lines to the North Coast (a distance of approximately 70 kilometres) but considered that a development to Gympie (a distance of approximately 30 kilometres) would sufficiently address the forecast reliability constraints. While acknowledging that the North Coast is a more central and strategic injection point to the region, PB considered that the development did not appear efficient in the short term and based on the particular constraint that triggers the project.

PB recommended that Powerlink's proposed capex for this project be reduced by $18 million to provide for the development of a 275 kV double circuit line from Woolooga to Gympie rather than to the North Coast and the installation of the transformer at this location. PB considered that a staged approach to the development would allow the remaining section of the line between Gympie and North Coast to be developed later, as economically and technically required.

CHC stated that PB's recommendation to reduce the scope of the project in this way would have implications for Energex and that additional cost may arise for electricity consumers. CHC considered that there was insufficient information about the nature of the constraints in the northern Sunshine Coast to make an assessment of PB's recommendation.

The AER notes CHC's comments on this project and therefore seeks further information from Powerlink and Energex on the nature of the constraints in the northern Sunshine Coast area and the impact on customers resulting from PB's recommendation.

However, for its draft decision, the AER accepts PB's recommendation that a shorter line project would represent a more efficient alternative to address the forecast reliability constraints. It is also noted that Powerlink would be able to develop the remaining section of the 275 kV line between Gympie and North Coast when it can be justified. Powerlink advised the AER that this would reduce forecast capex by $16 million.

7.2 New information from Powerlink on Woolooga to North Coast project

Powerlink advised that this project overcomes forecast thermal and voltage limitations on the Energex 132 kV network supplying loads at Cooroy, Sunrise Hill and Noosaville (in the north of Queensland's Sunshine Coast). The project was planned jointly with Energex and involves constructing approximately 70 km of double circuit 275 kV line (initial parallel operation) to the North Coast area.

Powerlink said that during PB's review PB did not mention to, nor request information from, Powerlink on its recommended option of injection at Gympie. Powerlink provided a detailed comparison of 3 options to PB during its review.

Establishment of a substation at Gympie was considered in early option analysis during joint planning with Energex, but was discarded as it was not the lowest cost overall (i.e. long term) than other options. In addition, development at Gympie was strategically inferior for the ongoing network development of both organisations. PB also acknowledged that the North Coast is a more central and strategic injection point to the region.

Powerlink has now carried out an economic comparison of PB's and Powerlink's options using NPV analysis consistent with the requirements of the regulatory test and the regulatory framework. This necessarily involves consideration of both the initial augmentation and other developments which are forecast to be required in the longer term.

PB's recommendation establishes a 275/132 kV substation at Gympie in 2011. Easement and site acquisition constraints will not allow a 275/132 kV injection to be established at the existing Energex substation. Powerlink also advised that a line route to this site would involve underground cable, which would add over $9 million to the cost. However, Powerlink's initial assessments indicate it may be possible to establish a new 275/132 kV substation to the south of the town without the need to underground the transmission lines, and this option was analysed. This would address the initial thermal and voltage limitation between Woolooga and Gympie.

However, with this option, overloads are forecast to occur on lines between Energex's Gympie and North Coast substations in 2016 during an outage of the parallel line. Energex has already uprated these lines to their maximum possible design temperature of 100°C thereby deferring augmentation. PB's option therefore requires further transmission augmentation between Gympie and the North Coast in 2016. The NPV for the Powerlink Option is $64.4 million, and for the PB Option it is $66.9 million at a discount of 7%. Establishing the injection at the North Coast instead of Gympie also results in lower transmission losses. These loss savings have not been included into this economic analysis.

Details of this stage development were provided to the AER in response to a question to Powerlink. The stage 2 double circuit transmission line from near Gympie South to the new North Coast 275/132kV substation is constructed with both circuits strung (but operated parallel). This is economic due to the construction window falling within 5 years (during the off-peak construction window the Energex system must be N-1 compliant for an outage between Gympie and the North Coast without a 275kV injection at the North Coast substation).

The North Coast area is one of the fastest growing areas in Australia as it encompasses the coastal belt from Noosaville/ Noosa in the north to Caloundra in the south. This high development area is both geographically and electrically south of Gympie. For this reason injecting 275kV into Gympie only defers the need to establish the North Coast substation by 5 years (2016).

Energex's long term plan forecasts a total load of 760MVA for this area (including Gympie). This excludes Energex's plans to establish a 132kV link east from the North Coast substation to support the load of the North Coast area between Noosaville and Maroochydore (currently supplied via Palmwoods).

Of this total load, 240MVA would be at Gympie. PB's option would see three (3) 275/132kV transformers supplying essentially this load (two transformers at Woolooga and one at Gympie) with the majority of the load balance (520MVA) supplied from the North Coast substation.

The longer-term forecast of 520MVA (which excludes load transferred from the Palmwoods system) clearly establishes a need for a second North Coast 275/132kV transformer as the third stage of development. For the outage of the first transformer the Energex circuits between Gympie and Cooroy are thermally not capable of supplying this load. Voltage problems at the end of this radial supply would also be an issue.

Initial analysis indicates that the timing for this second transformer is approximately 2020. This analysis has not taken into account the transfer of load from the Palmwoods system nor any acceleration of the onset of the voltage problem.

The cost of these stage 3 works was not included in the NPV analysis performed for the PB option as the PB option was already shown not be the most efficient over the long-term. However, the full costs will be captured in the Regulatory Test that Powerlink and Energex will undertake in late 2007. Both Powerlink and Energex firmly believe that injection at Gympie first would not satisfy a full regulatory test analysis once all costs are captured (also including differential losses).

In addition to the technical and strategic reasons why the North Coast substation is the preferred option the additional environmental and community impact of PB's option cannot be ignored. Establishing a Gympie 275/132kV injection does not negate the need to establish the North Coast substation at a later date. In the longer-term it also does not reduce the scope of works required at this North Coast substation (i.e. two transformers). However, the PB option results in two communities being substantially impacted – Powerlink would argue one unnecessarily and inconsistent with the joint planning strategic alignment with Energex.

Including the future impacts on Energex's network in both options, the PB option has a higher NPV than Powerlink's proposal. PB's option is also strategically inferior for the longer term development and operation of both Powerlink's and Energex's networks, and has higher transmission losses.

7.3 Comments by Submitters on Woolooga to North Coast

Energex advised that it undertook a joint planning study with Powerlink to address the thermal and voltage limitations on the recently upgraded Energex network south of Woolooga which provides supply to Gympie, Cooroy, Sunrise Hill and Noosaville. Although the immediate limitation relates to the section of the line to Gympie, the sections south of Gympie are emerging issues which require subsequent reinforcement by 2016, and that the PB option did not take this into consideration.

7.4 CHC's Opinion on Woolooga to North Coast

Powerlink and Energex have presented a sound economic and strategic case for the original proposal to be reinstated. PB's solution addresses only a short term network limitation, but does not consider an equally serious limitation south of Gympie that emerges within a few years. Further, a 275 kV substation at Gympie would clearly be in the wrong place, and would virtually be redundant when the second limitation is addressed by extending Powerlink's 275 kV system to the North Coast. It is clear that the area of major load development will be adjacent to the North Coast and not near Gympie.

Powerlink has established a marginal economic case for its original proposal by considering only capital costs in its analysis, but it is clear that the cost of network losses (in the Energex network) would add to the differential cost. The environmental impact of establishing an unnecessary 275 kV substation (with associated 132 kV lines) at Gympie should not be ignored either.

CHC's opinion is therefore that the original proposal put forward by Powerlink is more efficient, more strategic and more environmentally responsible than that proposed by PB, and that it should be reinstated in the capex allowance.

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1 April 2007