PLANNING REPORT

NORTH COUNTRY

Transmission System Reinforcement

Project No: T0180069

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Planning Projects Section

Network Planning & Development

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1 Executive Summary

The North Country electricity network is a long network spanning 400km from the northern outskirts of Perth to north of Geraldton. The length of the network and its original purposes mean that it is electrically weak and has limited capacity to supply load. The network characteristics and their relationship with the rest of the interconnected system mean that capacity to connect generators to this network is also limited.

This report reviews the basis for a proposed major network augmentation project to enhance capacity for the region that entailed construction of a 330kV transmission line from Pinjar (northern outskirts of Perth) to Moonyoonooka (just outside Geraldton).

The study results and analysis from this review show that the major reinforcement to the northern part of the North Country network can be delayed compared with previous project proposals – until 2015/16 under the underlying (natural) load forecast which does not include the connection of any block loads. Notwithstanding this, some minor network augmentation is required by 2011/12 but this is of substantially lower cost than the originally proposed augmentation.

In addition to the delayed implementation date, the range of options available to resolve the impending capacity constraints has broadened and there is a real opportunity to deploy non-network solutions, such as demand management or local generation to defer large investments in this region.

The potential to use these non-network resources to manage risk in uncertainty of load forecasts is highly valuable and the delayed requirement date for reinforcement provides time to enhance understanding and to develop a strategy to successfully deploy these options.

This review has found that the primary capacity constraint is a voltage stability issue and that is best solved by the installation of a Statcom at a considerable cost saving rather than the previously proposed new transmission line. The Statcom is a device that uses power electronics to provide dynamic reactive power support to the network.

A new transmission line may be required by 2015/16 or earlier based on the connection of block loads, further work needs to be conducted to determine the preferred option. This work will involve consideration of greater needs for transmission network capacity throughout the region, above the purely the natural load growth of the region. The impacts and benefits of major block loads and substantial new generation sources will contribute to the selection of the optimum solution.

2 Introduction

The North Country transmission network provides electricity supply to the Mid-West region of Western Australia. Geraldton is the major regional centre for this area servicing both the agricultural and mining industries.

The North Country electricity network is a long network spanning 400km from the northern outskirts of Perth to north of Geraldton. The length of the network and its original purposes mean that it is electrically weak and has limited capacity to supply load. The North Country network was originally established to supply a modest amount of load to a regional, agricultural centre.

The network characteristics and their relationship with the rest of the interconnected system mean that capacity to connect generators to this network is also limited. The location and layout of the regional electricity network is shown in Figure 1: North Country Electricity Network below.

Figure 1: North Country Electricity Network

Load forecasts indicate that there is an impending problem where electricity demand will exceed supply capacity to this region.

Western Power had proposed a major network augmentation project to enhance capacity for the region that entailed construction of a 330kV transmission line from Pinjar (northern outskirts of Perth) to Moonyoonooka (just outside Geraldton). This proposed project received Regulatory Test approval in 2007 and NFIT Pre-Approval in 2008. However, more refined cost estimates resulted in substantially increased costs associated with the proposed project. A review during 2009 led by the Department of Treasury and Finance and the Office of Energy recommended undertaking the proposed project in stages. Subsequent to this decision Western Power undertook to review the project, its costs and drivers in order to submit a Business Case to government and if, appropriate to prepare revised Regulatory Test and NFIT Pre-Approval submissions.

This document summarises the findings of this review relating to the northern section of the North Country Region – the original driver for the project being the need to maintain a secure and reliable supply of electricity to existing loads in the Geraldton region.

Also under important consideration is Gindalbie Metals who are proposing to establish a new mine at Karara and were intending to connect to the 330kV transmission network at Eneabba and require a supply of 85MW in 2012, rising to 108MW in 2013 (diversified loads).

Therefore, this document also investigates how the proposed connection to supply Gindalbie will affect future decision making in relation to network augmentation. The need for this is to establish a basis for determining appropriate contributions to the capital investment in relation to work required to supply power to Gindalbie.

3 Network Planning

3.1 Overview of Planning Criteria

Western Power is responsible for the planning and operation of the South West Interconnected Network (SWIN).

Planning activities for the SWIN and its component parts are undertaken with reference to the ***Technical Rules (DM#*** 3605551)***,*** as approved by the ERA. These ***Technical Rules*** define the limits for operation of the network and the considerations to be made in determination of the transmission line power transfer limits required to maintain safe and reliable operation of the network.

The technical requirements that apply to the design and operation of the network include:

- performance standards in respect of service standard parameters; and
- network planning criteria, including contingency criteria, steady-state criteria, stability criteria and quality of supply criteria.

In its planning activities Western Power has identified constraints in its ability to meet future needs of the part of network referred to as the North Country network. The particular clauses of the ***Technical Rules*** that are of particular concern in this region are:

- 2.2.7 Transient Rotor Angle Stability
- 2.2.9 Short Term Voltage Stability
- 2.2.11 Long Term Voltage Stability
- 2.5.2.2 N-1 Criterion

Each of these criteria are given in detail in 0.

3.2 Network Capability

The capability of the North Country network has been assessed using a range of load forecast scenarios (refer section 3.4 below). This assessment has identified impending constraints to the supply of growing load in the North Country network.

<u>**This report focuses on the area north of Eneabba and Muchea. This is the area in which the supply of natural load growth is constrained.**</u> The network in this region is also constrained for the connection of new large loads or generators.

There are also limitations within the network south of Eneabba, however these are only breached through the connection of new large loads or generators and will be addressed through a separate report.

The system studies undertaken in preparation of this report (refer Appendix A) demonstrated that the primary capacity constraint in the region is voltage stability, followed by thermal constraints. The voltage constraint is related to clause 2.2.9 (Short Term Voltage Stability), the secondary thermal constraints are related to clause 2.5.2.2 (N-1 Criterion) of the Technical Rules.

Many transmission lines within the North Country network have been designed to similar standards using the same conductor. Therefore they have similar thermal properties. Consequently, once one of the lines nears its thermal capacity then other lines are not far from reaching the same limit. Where there are two lines operating in parallel to provide security to the network, and one is identified as approaching its capacity limit, the other will not be far off and will also reach that limit at the same time or within a year or two.

3.3 Determination of Network Capacity in the Constrained Area

The definition of network capacity in the constrained area is complex. Due to the weak nature of this part of the transmission network (a result of the long distance between Geraldton and the remainder of the SWIS), local generation sources are used to supplement the network capacity. A review of the network capacity and performance has been completed (DMS#6622335) which identified some alterations to the present understanding of network capacity.

The capacity of the system is presently considered to be around 135 MW (net of losses[1]), comprised of:

- Transmission capacity (45MW net of losses),
- with support from local generation (about 90MW).

The local generation component is primarily provided by Mungarra Power Station (85MW) and with minor contribution from Walkaway Windfarm (5MW). The appropriate capacity level to assign to these generators is currently under review and there is potential for a slight increase, which could further defer the thermal limitation. Any effect on the voltage stability limit is likely to be neutral or negative.

The network capacity is limited by voltage stability and there is a risk of under voltage load shedding in the event of a network fault. By addressing the voltage stability constraint, network capacity could be increased to 65MW (net of losses), which equates to the thermal capacity of the transmission lines supplying the area. This will increase the total system capacity to 155MW.

The main outcomes of the network capacity review were that:

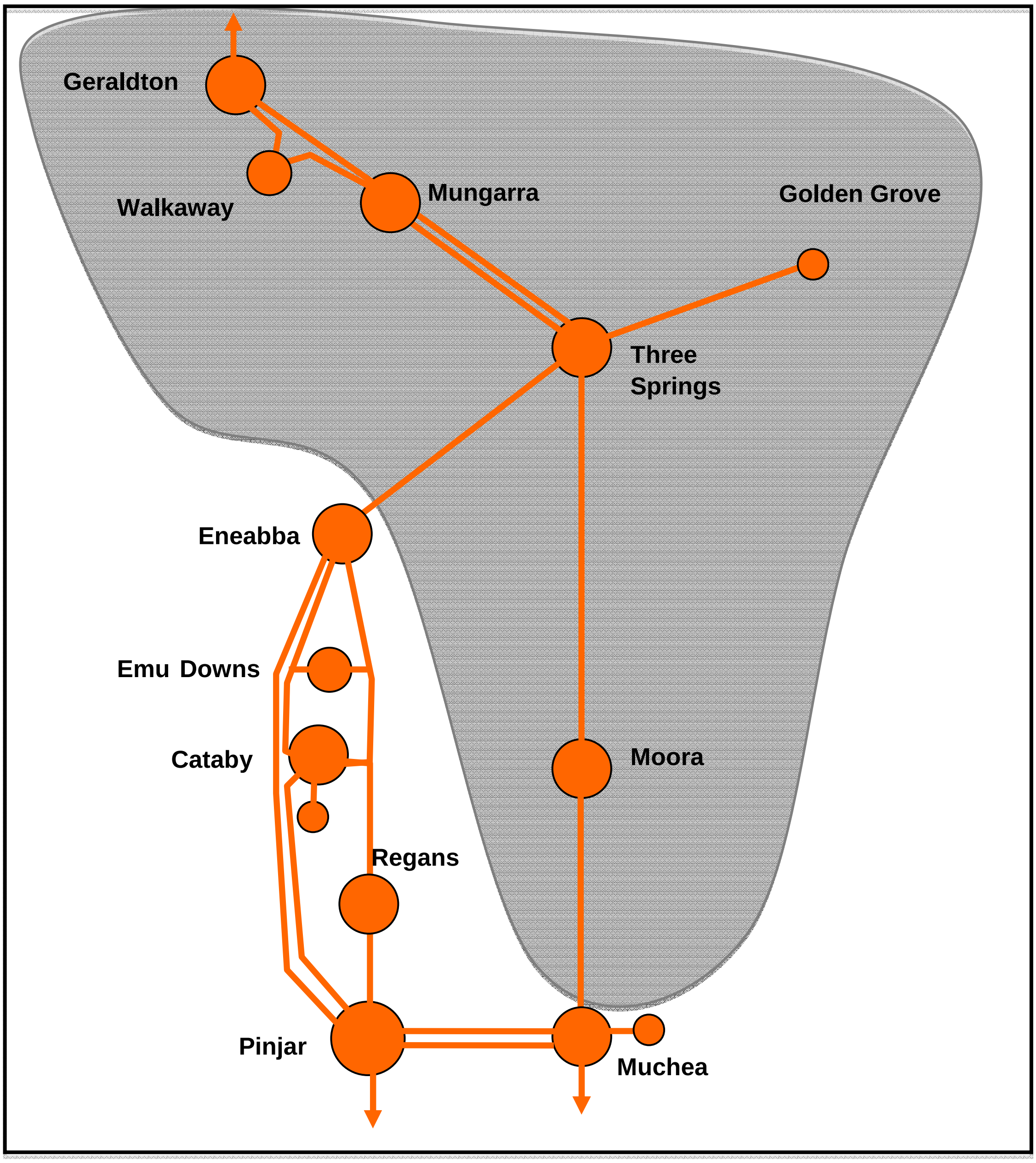
1. Capacity is adequate until 2012, and with some relatively simple work can be increased to provide sufficient capacity until 2016 to meet the underlying load forecast which does not include the connection of any block loads.

2. There are a broader range of solutions to constraints than previously considered viable. The previously identified constraint limiting network capacity had been related to rotor angle instability, which limited the range of solutions available as it meant that additional generation could not be connected without transmission network reinforcement. The new constraints (voltage stability and thermal) can potentially be resolved through non-network alternatives.

3. An upgrade to protection systems (relatively inexpensive work) would increase transmission capacity from 45MW to 50MW (net of losses).

[1] The losses in the North Country system are very high due to the long length (and resulting high resistance) of the transmission lines through which power flows.

Figure 2: Network Diagram – Constrained Area:



The constrained area of the network is north of Muchea and Eneabba and this report concentrates on that region. The initial constraint is maintaining voltage stability in Geraldton during a fault on the transmission line from Mungarra to Geraldton.

Subsequent constraints relate to the capacity of the 132kV transmission lines from Muchea to Moora and from Eneabba to Three Springs. After these constraints, the capacity of the transmission lines between Mungarra and Geraldton become an issue.

3.4 Load Forecasts

Present forecasts indicate that demand for electricity in the constrained area will exceed the voltage stability limitation of 135MW by 2012 and the thermal limitation of 155MW by 2015, for a Central Load forecast scenario.

Low, Central and High case forecasts have been produced – the timing for reinforcement would be advanced under a high load forecast and deferred under a low load forecast scenario.

Under the high case load forecast, the load will exceed 155MW by 2016 and for the low case load forecast, load does not exceed 155MW until 2017.

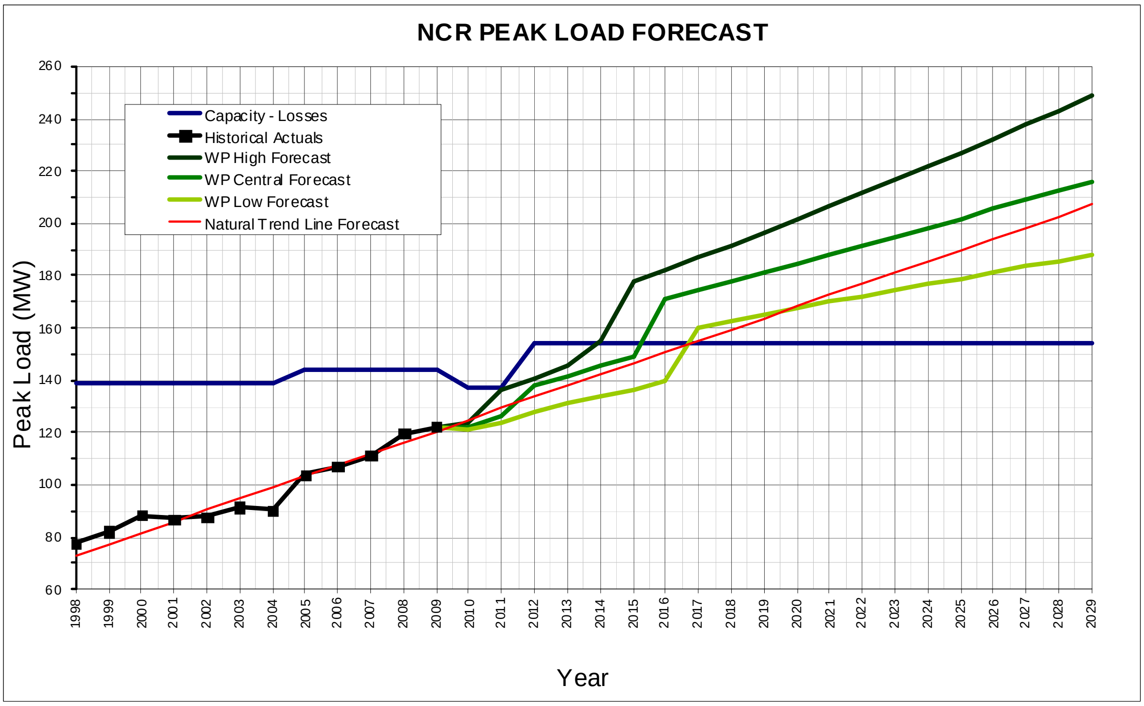


Figure 3: Load Forecast Scenarios

The forecast scenarios above demonstrate that the potential block load of around 25MW plays an important role in determining the extent of major reinforcement in the future.

For the low case load forecast, major reinforcement could be delayed even further (to around 2020). The timing for reinforcement would not be substantially affected under the central or high case scenarios.

4 Background to the need for consideration of alternative (higher capacity) solutions

The Mid-West region is recognised as having the potential to be a major contributor to the economic development of Western Australia. The proposed Oakajee Port, developing mineral resources and the prospects for the area to make a substantial contribution to renewable and other low cost and low emission electricity generation are all expected to greatly enhance the importance of this area and the need for an expanded and secure electricity network linking the region with the wider interconnected network.

Any one of these proposed major developments has the potential to increase electricity demand in the region by a significant magnitude (double or more). Therefore in the selection of alternatives to provide for an incremental increase in capacity to supply natural load growth, the technical and economic impacts related to major step increases in load and/or generation wanting to connect to the network in this region warrant consideration.

There is potential that any new major augmentation required to supply one or more of these proposals would affect the optimal solution and/or timing for a solution to meet the natural load growth forecast.

4.1 New Loads

At present Western Power has received enquiries from 2 large mining projects for supply to a total of 360MW of load (undiversified) – over twice the present load and supply capacity of the region. Associated with these proposals are additional loads relating to export and pumping facilities. There are also proposals for a major industrial estate development in connection with the new Oakajee Port facility.

Details of the enquiries are provided in Table 4-1 below.

Table 4-1 **Loads (Updated in the submitted MWEP (southern section) Regulatory Test)**

Customer	Load (MW)	Date	Connection Method / Comments
Gindalbie Metals	80	2010	330kV connection to Eneabba
Extension Hill	120	2010	Connection at 330 kV at Three Springs and 330kV line to Extension Hill mine
Gindalbie Metals	95	2012	This brings the total load at Gindalbie Karara to 175 MW
Gindalbie Metals	65	2015	This brings the total load at Gindalbie Karara to 240 MW

***Note:** The dates and capacities given are according to the enquiries, not necessarily the latest information provided to the Forecasting section. This information is intended to be representative of the interest in the region rather than specific to the forecast.*

To connect loads of this magnitude would require substantial reinforcements to the existing electricity network.

Planning and commercial negotiations are in progress for the connection of the Gindalbie load. At this stage it is probable that to supply Gindalbie, a 330kV line will be constructed to connect from Neerabup Terminal to their mine site at Karara. Due to time constraints the existing 132kV network to Eneabba, a reinforced 132kV connection from Eneabba to Three Springs a 132kV/330kV transformer at Three

Springs and a 330kV line from Three Springs to Karara will be used to provide an initial supply to the mine until the full scope of reinforcement works can be completed.

4.2 New Generators

Western Power currently has enquiries from 15 potential power stations, representing proposals for over 2,200MW of generation. These proposals total more than twenty times the present generation in the region.

Almost 60% of the generation proposals utilise wind as a fuel source – reflecting the prospective nature of this region for high yielding wind farms and relatively straightforward access to land. Around 60% of the windfarm applications are located south of Eneabba. The differentiation is made between south and north of Eneabba, as Eneabba is the boundary between stronger and weaker parts of the North Country electricity network.

Details of the enquiries are provided in Table 4-2 (for connections south of Eneabba) and Table 4-3 (for connections north of Eneabba) below.

Note that the dates and capacities given in the tables below are according to the applications, not necessarily the latest information provided to the Forecasting section. The magnitude of generation applications against the present regional capacity and against the total system load dictates that not all of these proposals will proceed to connection. However realisation of just some of these proposals will require substantial additional network capacity to accommodate them. This information is intended provide an indication of the high level of the interest in the region.

Table 4-2 **Generator proposals (to connect south of Eneabba)**

Power Station	Added Capacity (MW)	Date	Connection Method / Comments	Fuel
TOTAL	**781**		Wind = 781;	

Generator names and capacities removed to maintain confidentiality

Table 4-3 **Generator proposals (to connect north of Eneabba)**

Power Station	**Added Capacity (MW)**	**Date**	**Connection Method / Comments**	**Fuel**
TOTAL	**715**		(wind = 532, gas = 170, other = 23)	

Generator names and capacities removed to maintain confidentiality

Previous studies undertaken in relation to the connection of windfarms to the North Country network indicated that there was limited capacity available within the system to accommodate them. In fact the Walkaway windfarm operates with a run-back scheme in place to prevent line overloads for certain line outage conditions. The constraints identified were located south of Pinjar and north of Eneabba.

These studies were conducted some years ago and could be reviewed given that there have been recent changes within the network around the fringes of the northern metropolitan area (most significant being the connection of a new line between Pinjar and Wanneroo in 2008, and the establishment of Neerabup Terminal in 2009). It is likely that there is now increased capacity to connect some windfarms located south of Eneabba, and some preliminary investigations have been completed to support this.

5 Potential Solutions

To provide the necessary network capacity to meet the forecast load, a number of solutions are available. These solutions include network reinforcement and non-network solutions such as demand management or generation options. A solution that uses a combination of these alternatives is also possible.

To address all the issues anticipated for the North Country network over the medium to long term, a number of reinforcements will be required. Each of the options outlined below form building blocks to an overall solution.

A Net Present Costs assessment has been made for combinations of these solutions. The relative costs for various options are discussed in section 6.2 below and detailed information is provided in Appendix D.

5.1 Solutions addressing the initial voltage stability constraints to enhance supply capacity in the Geraldton Region

A voltage stability problem has been identified which limits capacity to 135MW, some minor works are required to increase capacity to 140MW. Potential solutions to this constraint include increasing voltage support within the Geraldton region through the provision of dynamic reactive power sources (generators, Statcoms, SVCs), decreasing fault clearance times on protection systems, reinforcing the transmission network or limiting load through the use of demand management programs.

1A. Protection system upgrades and installation of dynamic reactive support

- Protection upgrade of the MGA-GTN 81 transmission line to achieve the required clearing times as per the Technical Rules (115ms for the local end and 160ms for the remote end).
- Install a 50MVAr SVC or a 20MVAr Statcom in the Geraldton region.

These reinforcements will increase the system capacity initially from 135MW to 140MW (protection upgrade) and then from 140MW to 155MW (dynamic voltage support).

A preliminary economic assessment demonstrates that using a Statcom would be preferred above an SVC. (Note that for this particular situation a smaller Statcom can be used compared with an SVC due to the greater short term overload capabilities of Statcoms and it is only short term capability required here.) This assessment is preliminary at this stage and based on very indicative costs.

1B. Transmission network augmentation

- Protection upgrade of the MGA-GTN 81 transmission line to achieve the required clearing times as per the Technical Rules (115ms for the local end and 160ms for the remote end), to raise the capacity limit from 135MW to 140MW.
- Establish a new double circuit transmission line from Eneabba to Moonyoonooka.

These reinforcements will increase the system capacity initially from 135MW to 140MW (protection upgrade) and then from 140MW to beyond 180MW (new transmission line). This option avoids the need for reactive support within the Geraldton region but advances major network reinforcement by 4 years.

Note that only the Eneabba to Moonyoonooka line reinforcement has been identified as a reinforcement that would provide support to the network to alleviate voltage instability. Preliminary dynamic studies looking at an alternative network reinforcement of a new line from Eneabba to Three Springs demonstrated that voltage stability would still be an issue and therefore this alternative is not considered here.

A Net Present Cost assessment of this alternative against the previous (Statcom) indicates that there is around 20% additional cost associated with advancing the new transmission line. Therefore the option to install a Statcom in the Geraldton region is preferred.

1C. Demand management (DM) – load curtailment, off grid generation resources

- Protection upgrade of the MGA-GTN 81 transmission line to achieve the required clearing times as per the Technical Rules (115ms for the local end and 160ms for the remote end) to raise the capacity limit from 135MW to 140MW.

- Establish sufficient demand management resources to cap load at 140MW. For 2011/12 this would require 2.6MW of DM, increasing to 12.5MW by 2014/15. Alternatively without the protection system upgrade, 7.6MW of DM would be required in 2011/12 rising to 17.5MW in 2014/15.

An initial assessment of prospectivity of this region for a demand management initiative has been completed (refer to DM#674153 NCR DM Investigation Summary).

The preliminary outcomes from this investigation indicate that there could be up to 23MW (undiversified) of Demand Management (load curtailment and off grid generation) readily available. Diversity between customer demand against system peak times would reduce this to between 8MW and 16MW at peak load times. This DM resource is in the form of standby (off-grid) generators located within customers' premises and some load reduction. Some of the sites already have contracts in place under the Independent Marker Operator's (IMO's) Reserve Capacity program that could be extended to provide a Network Control Service.

Further load reduction in the form of energy efficiency measures is also a possibility but further work is required regarding this. The amount, reliability and cost of this source is much less certain.

A Demand Management resource of this magnitude could defer the need for reinforcement by 1-2 years for the central load forecast. The potential for demand management to manage risk associated with load forecast uncertainty is high as the lead time to procure is far reduced compared to establishing network reinforcements.

Further work is currently underway to verify potential costs. This would need to be followed by an "Expressions of Interest" or tendering process. Western Power is currently working with the IMO to clarify the process for acquiring Network Control Cervices of this nature.

Therefore it is recommended that work on enhancing understanding of this option continue further into the next stage of options assessment.

1D. Local network support generation (grid connected)

- Protection upgrade of the MGA-GTN 81 transmission line to achieve the required clearing times as per the Technical Rules (115ms for the local end and 160ms for the remote end) to raise the capacity limit from 135MW to 140MW.

- Establish sufficient demand management resources to cap load at 140MW. For 2011/12 this would require 2.6MW of DM, increasing to 12.5MW by 2014/15. Alternatively without the protection system upgrade, 7.6MW of DM would be required in 2011/12 rising to 17.5MW in 2014/15.

Previously the option of using local generation as a Network Control Service to support the Geraldton load had been discounted due to the phenomena of rotor angle instability and the understanding from previous system studies that local generation would exacerbate this problem. These previous studies were conducted in 2002 and changes within the SWIS during the intervening time have altered the system constraints. As rotor angle stability is no longer the limiting factor for this region there is now an opportunity for the connection of local generation to defer or mitigate the need for network augmentation.

Preliminary dynamic studies at up to 180MW loading indicate that a single 40MW gas turbine would provide marginal voltage stability while two 40MW turbines would provide adequate voltage stability. These studies have been undertaken with generic generator characteristics and for assumed connection locations. They do indicate that this option is feasible and it is therefore recommended that similar to the Demand Management option; work continues, to further develop an understanding of the issues and to assess the costs and system performance issues associated with specific proposals.

It should be noted that the thermal capacity of the network limits the ability for generators to connect as standard market participants (i.e. unconstrained). The existing generation in the region has contracted virtually all the available network capacity (the generators export load from the North Country network during low load and high generation output (high wind) times. Therefore a generation solution would be in the form of a Network Control Service that would be limited in its ability to participate in other aspects of the supply market (such as the Reserve Capacity market or general dispatch).

Load duration curves for the entire system including wind generation have been included in Appendix C to provide an indication of how the present generation utilises the transmission network capacity. Generators connected as Network Control Service generators would normally operate at times of low wind farm output and high area load.

5.2 Solutions addressing the 155MW constraint to enhance capacity in the constrained area (northern part) of the North Country Region

These potential solutions will enable the supply capacity for the Geraldton region to be increased from 155MW.

2A. Transmission line upgrades (increase thermal capacity of existing transmission lines)

- Assuming that the voltage stability issues had been addressed using option 1A, 1C or 1D above (minimal DM or local generation procured), the following line uprates would be required (timing noted in brackets):
  i. Muchea to Moora (2016)
  ii. Eneabba to Three Springs (2016)
  iii. Mungarra to Walkaway to Geraldton (2016)
  iv. Mungarra to Geraldton (2016)
  v. Three Springs to Mungarra (2020)
  vi. Moora to Three Springs (2025)

As there are two lines between Mungarra and Geraldton to be uprated and these would most probably require a complete rebuild of the existing lines (they are presently rated to operate at 85°C) a new (3rd) transmission line has been included in the economic assessment as this is a less expensive option than rebuild of 2 lines.

Also the cost of uprating Moora to Three Springs is around 80% of the cost of establishing a new line from Three Springs to Eneabba and as the new line would eliminate this problem as well as provide additional network support it has been included in the cost assessment rather than the line uprate.

An economic assessment for this option is not entirely complete as this option does not provide a solution to the inherent electrical weaknesses of the transmission network and results in further voltage stability issues developing with minor and incremental load growth in the very short term. It has been completed to demonstrate that an incremental reinforcement program would not provide any cost benefit compared to the other options considered, with far less benefit to network capability.

2B. New 132kV transmission line (Eneabba to Moonyoonooka/Geraldton)

- Establish a new double circuit transmission line from Eneabba to Moonyoonooka.

This option increases network capability in a number of ways. It assists in strengthening the transmission network through providing a stronger interconnection between Geraldton and the remainder of the SWIS. This reduces the possibility of further voltage stability or rotor angle stability issues developing in the future. It also reduces loading on critical lines during network outages (and also under normal conditions) by providing an alternate flow path.

The largest drawback with this option is the length of transmission line to be constructed. Additional work will be required in around 2025, which has been included in the NPC assessment.

2C. New 132kV transmission line (Eneabba to Three Springs)

- Establish a new double circuit transmission line from Eneabba to Three Springs.

This option increases network capability by providing an alternate flow path to reduce loading on the two most critical lines during network outages (and also under normal conditions). However it does not aid in alleviating other line overloads forecast for further into the future and it does not enhance the electrical strength of the network sufficiently to reduce the risk of future voltage instability issues recurring.

This option will require additional new lines in the future and will require additional dynamic reactive power support compared with the new transmission line from Eneabba to Moonyoonooka. The new transmission lines have been included in the NPC assessment for this option.

Further detailed studies are required to quantify the additional dynamic reactive support that would be required with this option.

An economic assessment of alternatives indicates that this option is likely to cost more than option 2B (in Net Present Cost terms). It is therefore a higher cost and lower technical benefit option and is unlikely to be recommended.

2D. Demand management – load curtailment, off grid generation resources

- Establish sufficient demand management resources to cap load at 155MW. For 2015/16 under the underlying load forecast this would require 24.6MW of DM, assuming that the transmission capacity had been upgraded to 155MW. Otherwise load would need to remain capped at 135 or 140MW and the DM requirement would be up to 44.6MW by 2015/16 under the underlying load forecast.

Refer to discussion under option 1C above. It is recommended that work on developing a greater understanding of DM resource continues, as any DM would be beneficial in deferring the need for network augmentation.

2E. Local network support generation (grid connected)

- Establish sufficient local generation to cap load at 155MW. For 2015/16 under the underlying load forecast this would require 24.6MW of DM, assuming that the transmission capacity had been upgraded to 155MW. Otherwise load would need to remain capped at 135 or 140MW and the DM requirement would be up to 44.6MW by 2015/16 under the underlying load forecast.

Refer to discussion under option 1D above. It is recommended that system studies into specific local generation proposals be completed as an effective and cost efficient local generation resource could be beneficial in deferring the need for network augmentation.

5.3 Solutions that rely on other network augmentations (specifically the 330kV reinforcement to supply Gindalbie)

The load forecast used in studies relating to the options outlined above constituted natural load growth and did not include major new customers such as the proposed mines at Karara or Extension Hill. The studies did not consider new generators that may connect to the network within this region.

There are a number of significant new load and generator proposals for this region. All of the load proposals are substantially larger that the total existing load and network capacity in the region. The need to supply loads of such magnitude introduces a new set of constraints south of Eneabba/Muchea and therefore a major network augmentation will be required to supply any one of the proposals.

Of immediate concern, Gindalbie Metals have applied to connect a large mining load to the network, located east of Three Springs. It is proposed to connect this load using a 330kV transmission line from the Perth metropolitan area to Three Springs and then on to the mine site further east. As it will take some time to establish this connection, an interim solution to provide start-up supply has been proposed. Under this interim arrangement, Gindalbie would establish a new transmission line from Eneabba to their mine site, install a 132/330kV step-up transformer and utilise the existing 132kV network capacity between Perth and Eneabba. This will provide limited and unsecure supply until the 330kV transmission line to Perth can be constructed. (Details updated in the supporting MWEP (southern section) Regulatory Test and NFIT documentation.

If this work proceeds then the base network will change and consequently the optimum solution to reinforce the network north of Eneabba/Muchea will be affected.

Therefore another set of solutions have been considered, to understand how the selection of a least cost solution to address the capacity issues within the constrained area would be affected by the potential reinforcement of the transmission network at Three Springs that would be required to facilitate the proposed connection of Gindalbie's Karara mine site.

These solutions would not be effective without the 330kV transmission line from Neerabup to Three Springs and a 330/132kV interconnection at Three Springs.

3A. Transmission line upgrades (increase thermal capacity of existing transmission lines)

The installation of a 330/132kV transformer at Three Springs presents the opportunity to consider an alternative option to enhance the supply capacity in the constrained part of the North Country network.

The 330/132kV transformer will provide some additional support to the voltage stability of the network and could therefore enable the dynamic reactive support project to be deferred.

Therefore there may need to be some risk borne until the voltage support issue is resolved. This risk may be managed through the use of DM or local generation.

Otherwise a Statcom would need to be installed in the Geraldton region. Further, detailed studies are required to confirm the needs.

As load in Geraldton grows the transformer will not provide enough voltage support and voltage instability may become a problem in the future.

From a thermal capacity perspective the 330kV transmission line and 330/132kV transformer act in a similar manner to option 2C above. The 330kV line and transformer provide an additional network element that will reduce the loading of transmission lines south of Three Springs during the most critical network outages.

Similar to option 2C described above, this reinforcement does not alleviate transmission line overloads north of Three Springs, that are anticipated further into the future. Therefore this option entails line upgrades in the future and this work is included in the Net Present Cost assessment for this option. Note that these transmission line reinforcements may provide enough support to alleviate any voltage instability issues. Further, more detailed studies are required to determine the support provided.

3B. Demand management – load curtailment, off grid generation resources

Demand management could be used further into the future to defer the network reinforcements anticipated to relieve network overloads north of Three Springs.

Refer to discussion under option 1C above for further information.

3C. Local network support generation (grid connected)

Local generation as a Network Control Service could be used further into the future to defer the network reinforcements anticipated to relieve network overloads north of Three Springs.

Refer to discussion under option 1D above for additional information.

6 Option Assessment

A Net Present Cost assessment has been completed for the main network reinforcement options under consideration. In future these options may be modified slightly by the use of demand management and/or local generation resources as Network Control Services.

6.1 Notes regarding the options assessment

This is a baseline case to use in the Gindalbie Business Case.

Note that in the discussions above and in comparing options, most consideration has been applied to the network solutions. Ultimately however, an integration of non-network and network augmentations will most likely form the optimum solution. Further work needs to be done in the areas of non-network solutions to finalise option selection.

This report was initially commenced in order to determine a recommended reinforcement for the northern part of the North Country network. A major augmentation to meet the needs of the Geraldton region would not be required until at 2015/16 under the underlying load forecast and possibly later with the effective use of DM and Network Control Services - meaning that there may be time for non-network options before a final option selection needs to be made. Should the connection of any block loads proceed within the proposed timeline then the need to augment capacity will be brought forward.

Meanwhile, an augmentation to meet the needs of Gindalbie is likely to be required in the near future and this reinforcement may affect the selection of an optimum solution in the future.

By focussing on network only solutions at this stage, a baseline view of network augmentation for the Northern North Country network has been formed. This will enable a determination to be made on the impact (technical and financial) of the Gindalbie reinforcement on future northern North Country reinforcements. These impacts will be integral to developing the Business Case and NFIT for the supply to the new Karara Mine load (Gindalbie).

6.2 Options discussion

Six main options were included in the Net Present Cost assessment. These were essentially 3 variations on the initial work to resolve the voltage stability issue, 2 variations on the work to resolve the subsequent thermal capacity issue and a comparison option of work that is reliant upon the Gindalbie reinforcement works proceeding.

Preliminary assessments were made on a wider set of options and these were used to refine the main options considered above.

6.3 Option Descriptions

Option 1 - Protection upgrade, Statcom, new line ENB-MNT

This option entails the following program of works:

- 2012[3] Protection upgrade for the MGA-GTN 81 Line
- 2012 Install a 20MVAr Statcom in the Geraldton area
- 2016 Establish a 132kV double circuit transmission line between Eneabba and Moonyoonooka
- 2025 Establish a new transmission line between Pinjar and Cataby (operated at 132kV)

This option addresses the initial voltage stability constraint before addressing the thermal constraint of the network. The new transmission line from Eneabba to Moonyoonooka provides an alternative flow path that reduces line overloads for critical lines.

This option has additional benefits in that it will facilitate the connection of new, large block loads in the Geraldton region. Cost savings could be achieved though the use of demand management and/or local generation solutions to defer the major expense associated with the new transmission line.

Option 2 - Protection upgrade, SVC, new line ENB-MNT

This option entails the following program of works:

- 2012 Protection upgrade for the MGA-GTN 81 Line
- 2012 Install a 50MVAr SVC in the Geraldton area
- 2016 Establish a 132kV double circuit transmission line between Eneabba and Moonyoonooka
- 2025 Establish a new transmission line between Pinjar and Cataby (operated at 132kV)

This option is almost identical to option 1, the only difference is the use of an SVC instead of a Statcom in the Geraldton region. This option is expected to be slightly more expensive than option 1.

Option 3 - Protection upgrade, new line ENB-MNT

This option entails the following program of works:

- 2012 Protection upgrade for the MGA-GTN 81 Line
- 2012 Establish a 132kV double circuit transmission line between Eneabba and Moonyoonooka
- 2025 Establish a new transmission line between Pinjar and Cataby (operated at 132kV)

[3] Note: The dates provided above require work to be completed by the beginning of the year specified (to meet peak load for that year). E.g. work required by 2012 to be completed prior to January 2012.

This option is similar to option 1, but advances the new transmission line to 2012 obviating the need for either an SVC or Statcom. This option is more expensive than either option 1 or option 2.

Option 4 - protection upgrade, Statcom, new line ENB-TS

This option entails the following program of works:

- 2012 Protection upgrade for the MGA-GTN 81 Line
- 2012 Install a 20MVAr Statcom in the Geraldton area
- 2016 Establish a 132kV double circuit transmission line between Eneabba and Three Springs (replace existing single circuit)
- 2016 Establish a new transmission line from Mungarra to Rudds Gully
- 2020 Establish a new transmission line from Three Springs to Mungarra
- 2025 Establish a new transmission line between Pinjar and Cataby (operated at 132kV)

This option addresses the initial voltage stability constraint before addressing the thermal constraint of the network. The new transmission line from Eneabba to Three Springs provides an alternative flow path that reduces imminent line overloads but not those further into the future. Therefore additional line reinforcements are included in the Net Present Cost assessment.

This option may also require additional voltage support in the future.

Option 5 - Protection upgrade, Statcom, Thermal upgrade of transmission lines

This option entails the following program of works:

- 2012 Protection upgrade for the MGA-GTN 81 Line
- 2012 Install a 20MVAr Statcom in the Geraldton area
- 2016 Uprate the existing Muchea to Moora transmission line
- 2016 Uprate the existing Eneabba and Three Springs transmission line
- 2016 Establish a new transmission line from Mungarra to Rudds Gully
- 2020 Establish a new transmission line from Three Springs to Mungarra
- 2025 Establish a 132kV double circuit transmission line between Eneabba and Three Springs (replace existing single circuit)
- 2025 Establish a new transmission line between Pinjar and Cataby (operated at 132kV)

This option attempts to minimise costs by undertaking line upgrades before the construction of new transmission lines. The cost assessment demonstrates that this is not successful as the benefits from line upgrades are not sufficient to defer the need for new line construction.

This option may also require additional voltage support in the future.

Option 6 - protection upgrade, Three Springs 330/132kV

This option entails the following program of works:

- 2012 Protection upgrade for the MGA-GTN 81 Line
- 2012 330/132kV transformer at Three Springs

- 2016 Establish a new transmission line from Mungarra to Rudds Gully
- 2020 Establish a new transmission line from Three Springs to Mungarra
- 2025 Establish a new transmission line between Pinjar and Cataby (operated at 132kV)

This option is reliant upon the establishment of a 330kV transmission line from Pinjar to Three Springs to supply the proposed Karara mine site. A 330/132kV transformer interconnection at Three Springs will act similarly to a second 132kV transmission line from Eneabba to Three Springs (similar to option 4).

This option may require additional voltage support (or the implementation of a demand management program) during the construction period for the new 330kV transmission line. The cost of this voltage support has not been included in the option assessment below.

6.4 Financial comparison of options

The outcome of the NPC assessment is given Table 4 below.

Table 4: NPC Comparison of Options

Option		NPC	Rank
1	Protection upgrade, Statcom, New line ENB-MNT	$ 170 M	2
2	Protection upgrade, SVC, New line ENB-MNT	$ 175 M	3
3	Protection upgrade, New line ENB-MNT	$ 192 M	5
4	Protection upgrade, Statcom, New line ENB-TS	$ 185 M	4
5	Protection upgrade, Statcom, Thermal upgrade of transmission lines	$ 211 M	6
6	Protection upgrade, Three Springs 330/132kV transformer	$ 160 M	1

From this information, it can be seen that the voltage stability issue is best solved by the installation of a Statcom (rather than an SVC or advancing a new transmission line). That is, option 1 is a lower cost alternative compared with options 2 and 3.

Establishing a new line between Eneabba and Three Springs (option 4) is a higher cost alternative compared with the Eneabba to Moonyoonooka line (option 1) but lower cost than the thermal upgrade of transmission lines (option 5).

The cost difference between option 1 and option 4 is around 9% (i.e. within the accuracy of the estimates used). From technical and broader benefits perspectives, there may be additional advantages associated with option 1 that would enhance its position above option 4. It is anticipated that the construction of a new line from Eneabba to Moonyoonooka will enable increased opportunities for the connection of new loads and generators.

If the reinforcement to Gindalbie does proceed, then the connection of a 330/132kV transformer at Three Springs provides a positive financial benefit of around $10M (in NPC terms).

The sensitivity of the above results to various load growth scenarios and discount rates was tested. Sensitivity studies indicated no change to the rank of the top 3 options for the scenarios considered, however, there was a change to the potential cost benefit of option 6 over option 1. A comparison between options 1 and 6 for the various load growth scenarios is given in Table 5 below, further detail showing all options is provided in Appendix D.

For the high growth scenario the NPC of the baseline option was only slightly higher ($0.5M) at $190.3M compared with $189.8M for the option with Karara. For the low growth scenario the difference between the options was also reduced compared to the central case at $3M ($137M with Karara and $140M for the baseline option).

Table 5: NPC comparison of Options 1 and 6 for various load growth scenarios

NPC for Load Growth Scenarios			
Option	Central	High	Low
1	$ 170 M	$ 190^+ M	$ 140 M
6	$ 160 M	$ 190^- M	$ 137 M
Cost Benefit (Option 6 - 1)	$ 10 M	$ 0.5 M	$ 3 M

Therefore the presence of a prior network augmentation to facilitate the connection of Karara is likely to have a positive cost benefit for Western Power, but variations in load growth outcomes will affect this.

The cost of any voltage support or demand management program associated with option 6 (as previously commented upon) will detract from the potential cost saving.

To provide an indication of the extent to which the cost of voltage support could affect cost benefit, a sensitivity assessment has been undertaken, using the worst case scenario (the installation of a Statcom in the Geraldton region for Option 6). This scenario defines the upper limit of costs associated with Option 6 to identify the range within which the cost benefit will fall. Table 6 below provides the alternative NPC outcomes for Option 6 under this highest cost scenario.

Table 6: NPC comparison of Options 1 and 6 for various load growth scenarios, including voltage support in the Geraldton region for Option 6

NPC for Load Growth Scenarios			
Option	Central	High	Low
1	$ 170 M	$ 190 M	$ 140 M
6	$ 169 M	$ 199^- M	$ 146 M
Cost Benefit (Option 6 - 1)	$ 1 M	-$ 9 M	-$ 7 M

Table 6 demonstrates that if a Statcom is required as part of Option 6, then the cost benefit of Option 6 over Option 1 is reduced. There is a small benefit of $1M for a central load growth scenario, but for the high and low load growth scenarios, Option 1 provides a lower cost alternative.

This assessment has been provided to demonstrate the range of outcomes possible. As voltage support for Option 6 is only required for a short duration of around 12 months, until the 330kV transmission line form Neerabup is commissioned, less expensive mitigation measures such as a demand management program are likely to be used. Detailed studies are in progress to identify and scope an alternative set of measures that could be used for this short exposure time.

The above assessment demonstrates that for a central load growth scenario, Option 6 is a lower cost option than Option 1. Under the most expensive implementation of Option 6, it is a similar cost option compared to Option 1.

7 Conclusions & Recommendation

The study results and the detailed analysis show that the major reinforcement to the northern part of the North Country network can be delayed compared with previous project proposals. Some minor reinforcement work may be required by 2011/12 (depending on the whether the Gindalbie connection proceeds and the outcome of dynamic studies relating to that connection).

This minor network reinforcement work will entail protection system upgrades and the installation of dynamic reactive support in the Geraldton area.

The range of options available to resolve future capacity constraints has broadened and there is a real opportunity to deploy non-network solutions to defer large investments in this region. The potential to use these resources to manage risk in uncertainty of load forecasts is highly valuable.

Further study is recommended to better understand how non-network solutions can be integrated and to refine the estimated costs for these alternatives. The delayed need for reinforcement provides time to progress further assessment of these options and to develop strategies to make them effective and successful alternatives.

In comparing a baseline preferred network augmentation against the Gindalbie related proposal (option 6), option 1 should be used. This is the option that presents the least cost network augmentation solution.

In practice option 1 may ultimately be implemented at a later date, as part of a composite solution that includes non-network components. Further work will continue - to define and assess the benefits associated with alternative options and to recommend a reinforcement for 2015/16 or earlier depending on the likelihood of the connection of proposed block loads connecting in the Geraldton region. The conduct and outcome of this further work will be dependent on whether the 330kV transmission line connection to Gindalbie's Karara (or another mine such as Extension Hill) proceeds. Ongoing assessment of load forecasts – particularly block loads and proposed generation connections - will also be important considerations.

Therefore, for purposes of this study, option 1 meets the immediate natural load growth needs of the network at the least cost and is therefore the baseline option.

The proposed reinforcement to supply Gindalbie has the potential to offer cost savings compared with the 'baseline' network reinforcement option. The cost benefit could be as high as $10M for the central load forecast case. The potential cost benefit may be reduced by through the use of non-network measures to defer the major cost items in the baseline scenario.

Variation to load forecast would also affect the potential cost benefit – it would reduce to $3M for a low growth scenario or $0.5M for a high growth scenario. Further benefit reductions would apply if it is necessary to install voltage support or demand management initiatives to support the network for a period during the interim supply of Karara through the existing 132kV network (prior to connection of a new 330kV line from Neerabup).

Appendix A Study Summary and Background Notes

Load flow studies were undertaken to identify when and where thermal issues become apparent so that options to resolve this could be identified. Study results are contained in DM# 6469511 and DM# 6469226.

PSS/e was used to conduct the studies, cases are saved in the following location:

Home\trans\ecchalm\NCR Studies 2009\

Cases are saved for three scenarios for each year – half windfarm output, no windfarm output and full windfarm output. For this set of studies the cases with no windfarm output are most critical (these cases maximise the reliance on power transfer across the transmission network). Future studies that consider the connection of more generation (particularly non-scheduled generation such as wind) will also need to consider the full windfarm output case in detail.

These studies were supported by dynamic studies completed by System Simulation and reported in DM# 6710197.

Refer to DM#6429512 for the load forecast used.

Note that although the forecast was adjusted numerous times throughout the study period, the adjustments were relatively minor. They have not been incorporated into the studies so that the study results remained consistent throughout the analysis period. The studies are representative of expectations. There may be some small variations in timing as a result of the minor changes to the load forecast. These should not be material to the outcome of the options assessment as the sensitivity analysis did not reveal any re-ranking of the top performing options for different load growth scenarios.

The system studies identified the following issues:

- Overload of transmission lines within the North Country region is of greatest risk when there is no output from windfarms and under high load conditions. Under these conditions, it is expected that there would be high ambient temperatures and little wind. For this reason, preliminary options that suggested the use of dynamic line ratings were ruled out (if overloading was of greatest risk during cool or windy conditions then dynamic line ratings could be increased to suit the conditions.)

- Loading of MUC-MOR (for an outage of ENB-TS) and ENB-TS (for an outage of MUC-MOR) exceeds 100% of line capacity under contingency conditions by 2013. Allowing for 5MW of output from the Walkaway wind farm and 84MW from Mungarra, loading of these lines does not exceed 100% until 2016. The highest loaded line is MUC-MOR.

- In addition, the following lines become subject to loading in excess of capacity in future years:
    - MOR-TS by 2017
    - MGA-GTN by 2017
    - WWF-GTN by 2018

- Refer to DMS#6469511 for a summary of results.

A number of alternatives were tested to understand the benefits and any subsequent reinforcements required.

- NPV analysis of options: DMS#6556559,
- Indicative Cost Estimates DM# 6507784.

Options considered in the preliminary assessment were:

1	Construct new ENB-TS81/82	Limited scope to expand for future needs
2	Construct new ENB-GTN81/82	Similar to above
3	Construct new ENB-MNT81/82	Again similar, but less congestion around Geraldton substation
4	Construct new line ENB-MNT91/92 (built 330kV, energised 132kV)	Operate at 132kV, less immediate capacity gain but allows major future expansion
5	Construct new PJR-MNT91/92	Expensive, provides for other projects (loads and generators)
6	Series Compensation & Generation or line uprates	Need to identify optimal location for SC; new (risky?) technology for WP; limited scope for future needs
7	330/132kV interconnect at Three Springs	Reliant on Gindalbie
8	HVDC link	Need to identify optimal location for link (ENB-GTN, (PJR-GTN) & future expansion potential; new (risky?) technology for WP

The preliminary option assessment did not support the adoption of the “riskier” options as there were no substantial financial benefits associated with either of these.

The riskier options were those which used new technology (for Western Power) and would therefore present technical and financial risks in their implementation – series compensation and HVDC. In favour of these options is the opportunity to gain experience and understanding of new technology that may be of benefit in future projects where this type of options is far superior.

The construction of new lines to Geraldton was ruled out do to congestion around the existing Geraldton substation and continued residential development in that area.

Line Data DMS#6447951 – New 132kV double circuit: 0.00053 + j 0.0022 pu

Inland line route ~ 252km vs Coastal line route ~ 260km

Line route difference about 3% - may not be substantial enough to warrant investigating one alternative over the other – especially given that one is already available. Further consideration given to this issue in the environmental assessments.

During the study phase a comprehensive review of the drivers for the need for reinforcement was undertaken, as was a review of the defined network capacity and the forecast. This is documented in DMS#6622335. An outcome of the review is the understanding that contrary to earlier expectations rotor angle stability is not a limit for this network at this point in time. Voltage stability and thermal capacity limits of the transmission lines are the main criteria driving the need for reinforcement. There was also some additional capacity identified through establishing clearer methods for accounting for network losses under contingency situations.

The review identified that the system capacity is heavily reliant on output from generators to supplement network capacity. There is room for developing further understanding of what would be an appropriate output to assign to generators in respect of their contribution to network capacity.

Updated Load Forecast

An updated load forecast was provided in May 2010 (refer DM# 6429512v14). This revised forecast was compared against the result of previous load studies to update the program of reinforcement works and consequently the estimated NPC of each option. Revised system studies were not undertaken using this forecast.

The updated works programs and NPC of options is included in this report.

Appendix B Excerpts from Technical Rules

(Clauses relevant to transmission planning for the North Country Region)

2.2.7 Transient Rotor Angle Stability

All ***generating units*** connected to the ***transmission system*** and ***generating units*** within ***power stations*** that are connected to the ***distribution system*** and that have a total rated output of 10 MW or more must remain in ***synchronism*** following a ***credible contingency event***.

2.2.8 Oscillatory Rotor Angle Stability

System oscillations originating from system electro-mechanical characteristics, electromagnetic effect or non-linearity of system components, and triggered by any ***small disturbance*** or ***large disturbance*** in the ***power system***, must remain within the ***small disturbance rotor angle stability*** criteria and the ***power system*** must return to a stable operating state following the disturbance. The ***small disturbance rotor angle stability*** criteria are:

(a) The ***damping ratio*** of electromechanical oscillations must be at least 0.1.

(b) For electro-mechanical oscillations as a result of a ***small disturbance***, the ***damping ratio*** of the oscillation must be at least 0.5.

(c) In addition to the requirements of clauses 2.2.8(a) and 2.2.8(b), the ***halving time*** of any electro-mechanical oscillations must not exceed 5 seconds.

2.2.9 Short Term Voltage Stability

(a) Short term voltage stability is concerned with the power system surviving an initial disturbance and reaching a satisfactory new steady state.

(b) Stable voltage control must be maintained following the most severe credible contingency event.

2.2.11 Long Term Voltage Stability

(a) Long term voltage stability includes consideration of slow dynamic processes in the power system that are characterised by time constants of the order of tens of seconds or minutes.

(b) The long term voltage stability criterion is that the voltage at all locations in the power system must be stable and controllable following the most onerous post contingent system state following the occurrence of any event specified in clauses 2.3.7.1(a) and 2.3.7.2 under all credible load conditions and generation patterns.

2.3.7 Power System Stability and Dynamic Performance

2.3.7.1 Short Term Stability

(a) The Network Service Provider must plan, design and construct the transmission and distribution systems so that the short term power system stability and dynamic performance criteria specified in clauses 2.2.7 to 2.2.10 are met under the worst credible system load and generation patterns, and the most critical, for the particular location, of the following credible contingency events without exceeding the rating of any power system component or, where applicable, the allocated power transfer capacity:

(1) a three-phase to earth fault cleared by disconnection of the faulted component, with the fastest main protection scheme out of service;

(2) a single-phase to earth fault cleared by the disconnection of the faulted component, with the fastest main protection scheme out of service;

(3) a single-phase to earth fault cleared after unsuccessful high-speed single-phase auto-reclosure onto a persistent fault;

(4) a single-phase to earth small zone fault or a single-phase to earth fault followed by a circuit breaker failure, in either case cleared by the operation of the fastest available protection scheme; or

(5) sudden disconnection of a system component, e.g. a transmission line or a generation unit.

(b) To ensure compliance with clause 2.3.7.1(a), the Network Service Provider must simulate the short term dynamic performance of the power system. Dynamic models of individual components must be verified and documented.

(c) In planning the transmission and distribution system, the Network Service Provider must:

(1) assume a transmission and distribution system operating configuration with equipment out of service for maintenance where this is provided for in the planning criteria specified in clause 2.5; and

(2) use a total fault clearance time determined by the slower of the two protection schemes, where the main protection system includes two protection schemes. Where the main protection system includes only one protection scheme, the back-up protection system total fault clearance time must be used for simulations.

2.3.7.2 Short Term *Voltage Stability*

(a) The assessment of the compliance of the transmission and distribution systems with the different short term voltage stability criteria specified in clause 2.2 must be made using simulation of the system response with the best available models of voltage-dependent loads (including representative separate models of motor loads where appropriate).

(b) The assessment must be made using simulation of the system response with the short-term overload capability of the voltage / excitation control system capability of each generating unit or other reactive source represented (magnitude and duration). This is to include representation of the operation and settings of any limiters or other controls that may impact on the performance of reactive power sources.

2.3.7.3 Long Term Voltage Stability

(a) In assessing the compliance of the transmission and distribution systems with the long term voltage stability criteria specified in clause 2.2.11, the Network Service Provider must first confirm that the transmission and distribution systems can survive the initial disturbance.

(b) The long term voltage stability analysis must then be carried out by a series of load-flow simulations or by using dedicated long-term dynamics software to ensure that adequate reactive power reserves are provided within the transmission and distribution systems to meet the long term voltage stability criteria in clause 2.2.11, for all credible generation patterns and system conditions.

(c) The Network Service Provider must model the power system for long term stability assessment and transfer limit determination purposes, pursuant to clause 2.3.7.3(b) using the following procedure:

(1) for terminal substations in the Perth metropolitan area, 3% of the total installed capacitor banks plus the reactive device that has the largest impact on the power system must be assumed to be out of service; and

(2) for other areas of the power system, including radials:

(A) the normal peak power system generation pattern, or other credible generation pattern determined by operational experience to be more critical, that provides the lowest level of voltage support to the area of interest must be assumed. Of the generating units normally in service in the area, the generating unit that has the largest impact on that area must be assumed to be out-of-service due to a breakdown or other maintenance requirements. If another generating unit is assigned as a back-up, that generating unit may be assumed to be brought into service to support the load area; and

(B) the largest capacitor bank, or the reactive device that has the largest impact in the area, must be assumed to be out of service, where the area involves more than one substation.

(3) In all situations the Network Service Provider must follow the following additional modelling procedures:

(A) all loads must be modelled as constant P & Q loads;

(B) the load or power transfer to be used in the study must be assumed to be 5% higher than the expected system peak load, or 5% higher than the maximum expected power transfer into the area. (The 5% margin includes a safety margin for hot weather, data uncertainty and uncertainty in the simulation). The power system voltages must remain within normal limits with this high load or power transfer;

(C) the analysis must demonstrate that a positive reactive power reserve margin is maintained at major load points, and that power system voltages remain within the normal operating range for this 5% higher load; and

(D) power system conditions must be checked after the outage and both prior to, and following, tap-changing of transformers.

2.3.8 Determination of Power Transfer Limits

(a) The Network Service Provider must assign, on a request by a User or System Management, power transfer limits to equipment forming part of the transmission and distribution systems. The assigned power transfer limits must ensure that the system performance criteria specified in clause 2.2 are met and may be lower than the equipment thermal ratings. Further, the assigned power transfer limits may vary in accordance with different power system operating conditions and, consistent with the requirements of these rules, should to the extent practicable maximise the power transfer capacity made available to Users.

(b) The power transfer assessed in accordance with clause 2.3.8(a) must not exceed 95% of the relevant rotor angle, or other stability limit as may be applicable, whichever is the lowest.

(c) Where the power transfer limit assessed in accordance with clause 2.3.8(a) is determined by the thermal rating of equipment, short term thermal ratings should also be determined and applied in accordance with good electricity industry practice.

2.5 *TRANSMISSION AND DISTRIBUTION SYSTEM* PLANNING CRITERIA

2.5.1 Application

The planning criteria in this clause 2.5 apply only to the ***transmission and distribution systems*** and not to ***connection assets***. The ***Network Service Provider*** must design ***connection assets*** in accordance with a ***User's*** requirements and the relevant requirements of section 3.

2.5.2 Transmission system

The ***Network Service Provider*** must design the ***transmission system*** in accordance with the applicable criteria described below:

2.5.2.1 N-0 Criterion

(a) A sub-network of the transmission system designed to the N-0 criterion will experience the loss of the ability to transfer power into the area supplied by that sub-network on the loss of a transmission element. Following such an event this power transfer capability will not be restored until the transmission element has been repaired or replaced.

(b) The N-0 criterion may be applied to sub-networks with a peak load of less than 20 MVA and to zone substations with a peak load of less than 10 MVA. The N- 0 criterion also applies to the 220 kV interconnection supplying the Eastern Goldfields region. In the event of an unplanned outage of the 220 kV interconnection supplying the Eastern Goldfields region the power system is expected to split into two islands. Arrangements are in place to supply the Kalgoorlie-Boulder city and Coolgardie town loads during an interconnection outage but Users outside these areas will need to make their own arrangements for any back-up generation requirement.

(c) For a sub-network designed to the N-0 planning criteria, the Network Service Provider must use its best endeavours to transfer load to other parts of the transmission or distribution system to the extent that this is possible and that spare power transfer capacity is available. If insufficient back-up power transfer capacity is available, load shedding is permissible. Where a supply loss of long duration, the Network Service Provider must endeavour to ration access to any available power transfer capacity by rotating the load shedding amongst the Consumers affected.

(d) At zone substations subject to the N-0 criterion, the Network Service Provider may, at its discretion, install a further supply transformer if insufficient back-up power transfer capacity is available to supply loads by means of the distribution system to allow planned transformer maintenance to occur at off peak times without shedding load.

2.5.2.2 N-1 Criterion

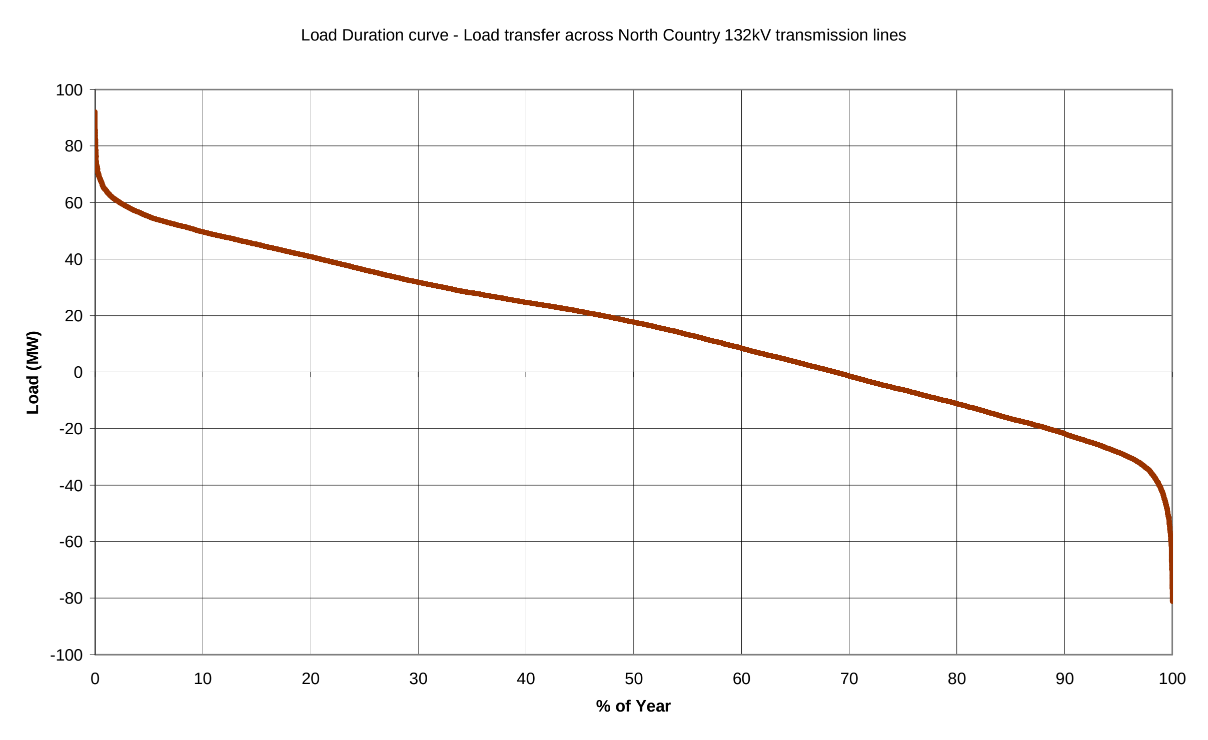
(a) Any sub-network of the transmission system that is not identified within this clause 2.5.2 as being designed to another criterion must be designed to the N-1 planning criterion.

(b) For sub-networks designed to the N-1 criterion (excluding a zone substation designed to the 1% risk or NCR criteria in accordance with clause 2.5.3.2), supply must be maintained and load shedding avoided at any load level and for any generation schedule following an outage of any single transmission element.

(c) Following the loss of the transmission element, the power system must continue to operate in accordance with the power system performance standards specified in clause 2.2.

Appendix C Load Duration Curve

Refer DMS#6679593 for load transfer across 132kV transmission lines (this is not the load duration curve as the contribution to load from generators is not included).



This curve demonstrates:

- During 2008/09 the transmission lines were operated beyond the 80MW thermal limit for a number of times.
- The loading of the transmission lines exceeded 80% of the thermal rating for around 1% of the time (around 88 hours).
- Load was exported from the North Country system (i.e. windfarm export exceeded local load) for over 30% of the time (indicated by negative load).

Refer to DMS#6189170 for complete load duration curve. This also includes a curve with only the windfarm contribution excluded.

This curve demonstrates that load exceeds 80% of the peak for only around 30 hours each year and exceeds 90% of the peak load for only around 15 hours per year.

This data indicates that the use of demand management initiatives could be very effective in deferring the need for network reinforcement.

Appendix D Net Present Cost Assessment of Alternatives

Detailed spreadsheet attached. Summary data:

Option		Forecast Scenario		
		Central	High	Low
1	Protection upgrade, Statcom, New line ENB-MNT	170.3	190.3	139.7
2	Protection upgrade, SVC, new line ENB-MNT	174.9	194.9	143.5
3	Protection upgrade, new line ENB-MNT	192.3	205.6	145.1
4	Protection upgrade, statcom, new line ENB-TS	184.6	211.9	155.8
5	Protection upgrade, statcom, thermal upgrade of transmission lines	211.4	244.2	170.6
6	Protection upgrade, statcom, Three Springs 330/132kV	159.8	189.8	137.1

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OPTION RANKING			
Option	Forecast Scenario		
	Central	High	Low
1	2	2	2
2	3	3	3
3	5	4	4
4	4	5	5
5	6	6	6
6	1	1	1

Sensitivity Analysis

Option		Central Growth		
		15%	7.5%	10%
1	Protection upgrade, Statcom, New line ENB-MNT	121.2	206.4	170.3
2	Protection upgrade, SVC, new line ENB-MNT	125.6	211.1	174.9
3	Protection upgrade, new line ENB-MNT	157.6	219.2	192.3
4	Protection upgrade, statcom, new line ENB-TS	127.1	227.1	184.6
5	Protection upgrade, statcom, thermal upgrade of transmission lines	142.7	262.9	211.4
6	Protection upgrade, Three Springs 330/132kV	108.7	198.4	159.8
6a[4]	Protection upgrade, statcom, Three Springs 330/132kV	117.5	207.9	169.0
Option		**High Growth**		
		15%	**7.5%**	**10%**
1	Protection upgrade, Statcom, New line ENB-MNT	143.3	222.7	190.3
2	Protection upgrade, SVC, new line ENB-MNT	147.7	227.4	194.9
3	Protection upgrade, new line ENB-MNT	170.4	230.6	205.6
4	Protection upgrade, statcom, new line ENB-TS	157.6	249.1	211.9
5	Protection upgrade, statcom, thermal upgrade of transmission lines	178.4	289.6	244.2
6	Protection upgrade, Three Springs 330/132kV	142.8	222.4	189.8
6a	Protection upgrade, statcom, Three Springs 330/132kV	151.6	231.9	199.1
Option		**Low Growth**		
		15%	**7.5%**	**10%**
1	Protection upgrade, Statcom, New line ENB-MNT	92.7	178.8	139.7
2	Protection upgrade, SVC, new line ENB-MNT	95.8	183.0	143.5
3	Protection upgrade, new line ENB-MNT	103.8	180.0	145.1
4	Protection upgrade, statcom, new line ENB-TS	100.9	200.9	155.8
5	Protection upgrade, statcom, thermal upgrade of transmission lines	105.6	225.8	170.6
6	Protection upgrade, Three Springs 330/132kV	90.9	176.6	137.1
6a	Protection upgrade, statcom, Three Springs 330/132kV	99.7	186.1	146.4

[4] Option 6A includes the provision of a Statcom in the Geraldton region as voltage support for the period prior to commissioning of the 330kV line from Neerabup to Eneabba/Three Springs. This is a worst case scenario as there are other lower cost options that will be scoped prior to investment in a statcom for a short time period.

List of works and timing for each option (base case only shown here, refer to attached spreadsheet for low and high cases):

Option 1 - Protection upgrade, Statcom, New line ENB-MNT		
Protection upgrades	MGA-GTN 81 Line	2012
Dynamic Reactive Support	20MVAr Statcom at Chapman	2012
ENB-MNT 81&82	Double CCT tower line	2016
PJR-CTB 83	Built at 330kV, operated 132kV	2025
Option 2 - protection upgrade, SVC, new line ENB-MNT		
Protection upgrades	MGA-GTN 81 Line	2012
Dynamic Reactive Support	50MVAr SVC at Chapman	2012
ENB-MNT 81&82	Double CCT tower line	2016
PJR-CTB 83	Built at 330kV, operated 132kV	2025
Option 3 - protection upgrade, new line ENB-MNT		
Protection upgrades	MGA-GTN 81 Line	2012
ENB-MNT 81&82	Double CCT tower line	2012
PJR-CTB 83	Built at 330kV, operated 132kV	2025
Option 4 - protection upgrade, statcom, new line ENB-TS		
Protection upgrades	MGA-GTN 81 Line	2012
Dynamic Reactive Support	20MVAr Statcom at Chapman	2012
ENT-TS 81&82	Double CCT tower line	2016
MGA-RUD 81&82	Double CCT tower line	2016
TS-MGA	Double CCT tower line	2020
PJR-CTB 83	Built at 330kV, operated 132kV	2025
Option 5 - protection upgrade, statcom, thermal upgrade of transmission lines		
Protection upgrades	MGA-GTN 81 Line	2012
Dynamic Reactive Support	20MVAr Statcom at Chapman	2012
MUC-MOR 81	Line Uprate	2016
ENB-TS 81	Line Uprate	2016
MGA-RUD 81&82	Double CCT tower line	2016
TS-MGA	Double CCT tower line	2020
ENT-TS 81&82	Double CCT tower line	2025
PJR-CTB 83	Built at 330kV, operated 132kV	2025
Option 6 - protection upgrade, statcom, Three Springs 330/132kV		
Protection upgrades	MGA-GTN 81 Line	2012
Dynamic Reactive Support	20MVAr Statcom at Chapman	2012
Three Springs	330/132kV transformer	2012
MGA-RUD 81&82	Double CCT tower line	2016
TS-MGA	Double CCT tower line	2020
PJR-CTB 83	Built at 330kV, operated 132kV	2025