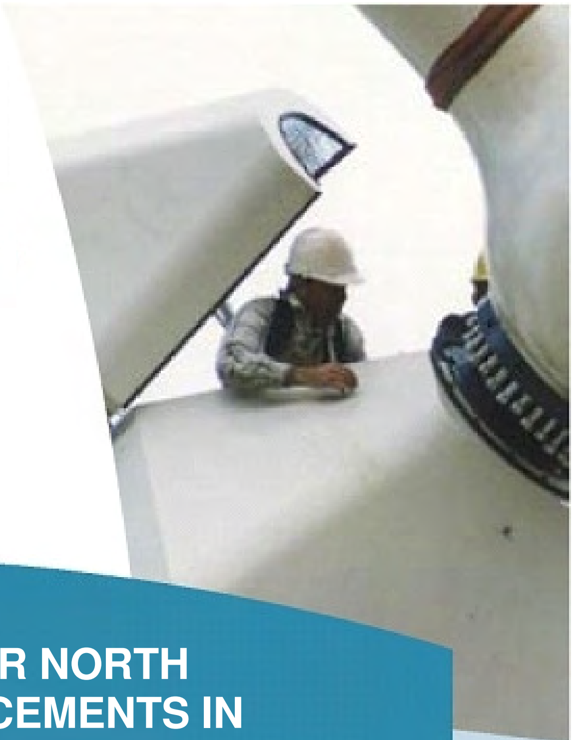
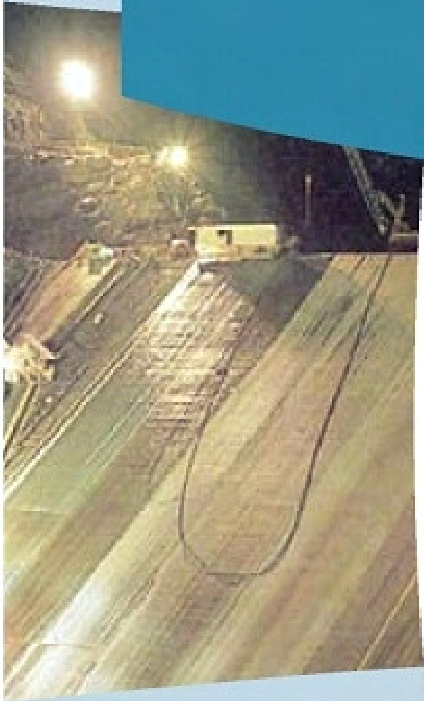
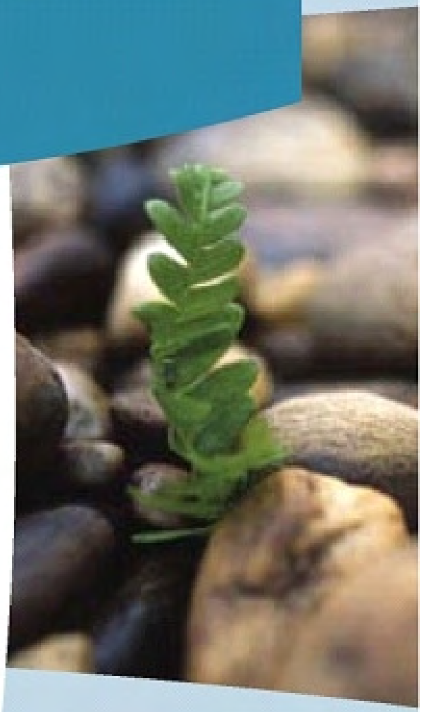
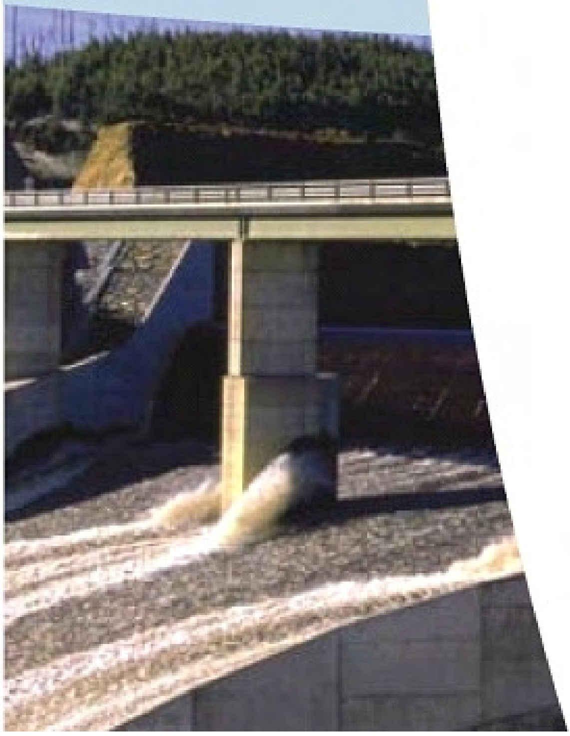


Hydro Tasmania
Consulting

DUE DILIGENCE STUDY FOR NORTH COUNTRY SYSTEM REINFORCEMENTS IN 2010, SYSTEM STUDIES REVIEW







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EXECUTIVE SUMMARY

This report shows the due diligence study results associated with the North Country system reinforcement requirement work done by Western Power Electricity Network Corporation (WP). The work is limited to find out:

i. Existing supply capacity for the North Country System (NCS)

ii. There will be no benefit to the NCS system by adding another gas turbine at Mungarra

iii. Necessity of reactive support device for the reinforcement option 2a.

The North Country system load area consists of north of the Pinjar power station and Muchea zone substation. Presently, the North Country power system consists of a 132kV transmission network running approximately 400km from south to north. WP studies show that the power transfer from south to north will not meet the growing demand of the area by the year 2010.

The NCS is an inherently weak system due to the long radial lines. The long and weak link between Geraldton and the remainder of the South West Interconnected System (SWIS) leads to low synchronising forces between generator groups, hence synchronous stability issues. Increase in local generation at Geraldton would further decrease the transfer limits.

Presently, the Transient Voltage Recovery (TVR) requirement of the technical code is used to determine the NCS power transfer limit.

HTC agrees that a 46MW transfer limit, based on the TVR criteria as indicated by the "Generation requirement for North Country System in 2006 (DMS#: 2468609)", is correct and may be more appropriate than the 65MW indicated in the "Invitation for submissions – Proposed improvement to the Mid West region's transmission network". It appears that the 65MW transfer limit has been selected in 2003 on the basis of pole slip criteria with 10% safety margin.

Hence the appropriate existing supply capacity in the region north of Muchea and Eneabba is approximately 132MW.

It is confirmed that an addition of a similar gas turbine unit to Mungarra power station will reduce the power transfer limit further and effectively there will be no or, at best, minimal net increase to the supply capacity in the NCS.

It is also confirmed that without any dynamic reactive support, the reinforcement option 2a may not be viable due to steady state voltage instability. Reactive reserve studies show that a SVC and Capacitor bank of 55MVArs minimum total capacity is required at Geraldton to meet the reactive reserve margin specified by the technical code. Any reactive support systems need to be designed to get 55MVAr even when the loss of the most critical reactive device.

Dynamic studies show that either a 40MVAr fixed capacitor bank with a 20MVAr STATCOM or a 65MVAr SVC is required to satisfy the TVR criteria for option 2a under an “n-1” contingency.

To comply with the reactive reserve and TVR requirements, installation of a 20MVAr STATCOM, 30x2 fixed capacitor banks and a 10MVAr SVC is one of the viable solutions. This can be further optimised and we recommend to conduct a detailed study if the reinforcement option 2a is approved to proceed.

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1. INTRODUCTION

Western Power's transmission network in the North Country System (NCS) extends 400km from Pinjar and Muchea to Geraldton and consists of 132kV transmission network. The simplified network arrangement of NCS is shown in Figure 1-1.

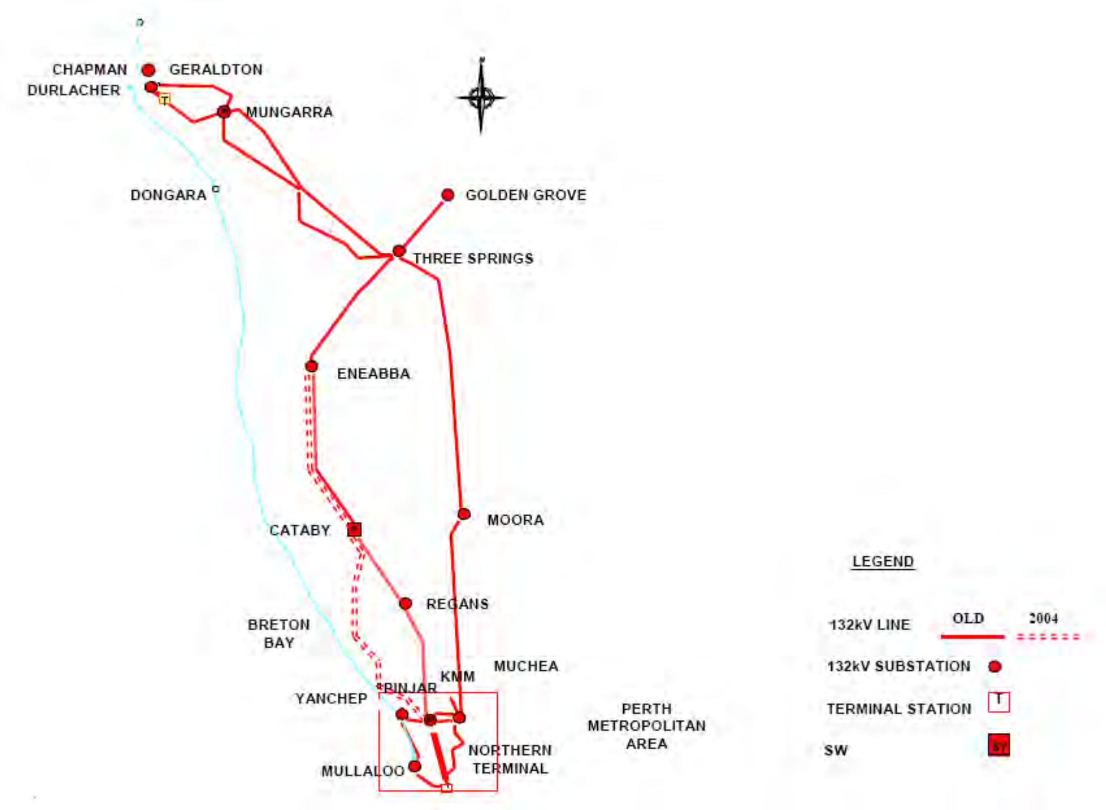

Figure 1-1 Existing network arrangement for North Country System

Presently, the majority of NCS power is supplied by the main transmission lines from Pinjar or Muchea but it is possible to operate gas turbines at Mungarra and Geraldton to meet the higher demand in the NCS, when necessary.

Western Power identify that, due to thermal, voltage and synchronous stability limitations, they may not be able to transfer large amounts of power to the NCS through their main 132kV network. Their studies indicate that by the year 2010 there would be a shortfall of power to the NCS if there are no system augmentations. WP conducted several studies relating to power transfer limits and sought Hydro Tasmania Consulting (HTC) to review their work.

HTC have conducted three study reviews, which are:

1. Review and confirm the existing capacity and transmission transfer limit to NCS

2. Confirm or review the previous study results which indicates the addition of another gas turbine (GT) to Mungarra will reduce the transmission transfer limit based on the existing system configuration

3. Review reactive support required for the reinforcement option 2a (in report DMS#: 3339124v5) with additional Eneabba (ENB) - Rangeway (RAN) 132kV double circuit line by November 2010. This study assumes that there are no MGA gas turbines in service.

This review has involved the assessment of the reports, written by WP, (references 1-4) as well as additional network simulations and analysis undertaken jointly by HTC and WP.

2. REFERENCES

[1] Major power supply reinforcement options for the North Country of Western Australia – Data for consultant's evaluation of options for the regulatory test purpose (DMS#: 3339124 v5) by *Western Power*

[2] Invitation for submissions – Proposed improvement to the Mid West region's transmission network by *Western Power*

[3] Generation requirement for North Country System in 2006 (DMS#: 2468609) by *Western Power*

[4] North Country System – Reinforcement requirements (DMS#: 3243705) by *Western Power*

[5] Interim electricity transmission access technical code by *Western Power*

[6] Study notes of North Country Region long term development plan (DMS# 1385824 v2) by *Western Power*

3. ASSUMPTIONS

1. Load growth and generation pattern indicated by WP accurately represents the actual system conditions.

2. Walkaway wind farm is not in service

3. STATCOMs at Walkaway wind farm remain connected to supply dynamic reactive support even if the wind turbines drop out due to low wind. STATCOMs will respond to system disturbances as per their dynamic model.

4. Emu Downs wind farm is not in service

4. STUDY RESULTS

There are four main criteria used by WP to evaluate maximum transfer limits, which are:

1. Thermal limits of the transmission line
2. Steady state voltage profile
3. Transient stability
4. Transient Voltage Recovery (TVR)

Based on the studies conducted, the transfer limits from Muchea and Eneabba to the North Country is defined by the TVR criterion. The TVR criterion for the NCS is defined in clause 2.3.3.5 of the technical code [5], which is:

2.3.3.5 Post-Fault Voltage Recovery Limit

> *b) In all country and remote areas, transmission system voltages after a fault on the system is cleared shall recover to levels above 80% of nominal operating voltage within 800ms counting from the end of the fault clearance.*

From reference [5].

4.1 Existing capacity and maximum transfer limit to NCS

Studies were conducted by varying the NCS load and investigating the four main criteria indicated above. Based on the dynamic simulation results, it was found that TVR at Chapman is the limiting factor for the transfer limit. Studies were conducted with and without Mungarra gas turbines in service and with different MW loadings on these gas turbines to cover the WP operational range. All simulations were carried out without considering any MW power output from Walkaway wind farm but some studies assumed dynamic reactive support available from the STATCOM at the wind farm terminals.

The critical contingency for the studies is a fault/trip of Eneabba (ENB) to Three Springs (TS) line during minimum generation available from Mungarra and the critical contingency is shifted to either fault/trip of Walkaway (WWF) to Geraldton (GTN) line or Walkaway (WWF) to Mungarra (MGA) line once MGA generation increases. The transfer limit results are tabulated in the Table 4-1.

Table 4-1 Transfer limit at ENB/MUC

Transfer limits at ENB/MUC in MW			
MGA Generation/Mode	No of STATCOM in service at WWF		
	0	27	54
No generation at NCS	46		
1 SC	63		
1 GT (10MW)	63		
1 GT (28MW)	46		
1 GT (28MW) & 1 SC	78		
2 GT (10MW & 28MW)	76		
2 GT (28MW & 28MW)	50		74
2 GT (28MW & 28MW) & 1SC		79	86
3 GT (28MW, 28MW & 28MW)	26	46	49

no verification studies were conducted by HTC

The transfer limit of NCS is defined as the summation of MW flow on the ENB to TS line at the ENB end and MUC to TS at the MUC end. Based on the definition, the loads south of ENB (including the ENB load) are excluded in the calculation of transfer limit.

A maximum load north of Eneabba and Muchea, under this definition, is shown in Table 4-2.

Table 4-2 Maximum possible load and MGA generation

Maximum possible load* at North of ENB/MUC in MW			
MGA Generation/Mode	No of STATCOM in service at WWF		
	0	27	54
No generation at NCS	43		
1 SC	59		
1 GT (10MW)	69		
1 GT (28MW)	71		
1 GT (28MW) & 1 SC	99		
2 GT (10MW & 28MW)	107		
2 GT (28MW & 28MW)	102		122
2 GT (28MW & 28MW) & 1SC		126	132
3 GT (28MW, 28MW & 28MW)	107	124	138

* excluding system losses

no verification studies were conducted by HTC

Therefore, based on the studies, the maximum possible loads north of ENB/MUC, that could be supplied from the existing network/generator arrangement (without WWF but with the STATCOM in service), is only 138MW. This is during operation of three MGA gas turbines at full output (28MW) and assuming all STATCOMs in the Walkaway wind farm are in service. It appears that depending on the generation schedule at MGA, the availability of some STATCOMs at Walkaway wind farm will improve the transfer limit. However there are some uncertainties about:

- The dynamic performance of the STATCOMs and the voltage control system of the wind farm
- The availability of the STATCOMs when the wind turbine is disconnected. When the wind turbines are in service, they will have an adverse impact on the system dynamic performance as they absorb more reactive power during faults; and
- Operational experience with Walkaway wind farm

Further work is required to examine the effect of Walkaway wind farm on the transfer limits.

HTC agrees that the 46MW transfer limit, based on TVR criteria as indicated by the "Generation requirement for North Country System in 2006 (DMS#: 2468609)", is correct and may be more appropriate than the 65MW indicated in the "Invitation for submissions – Proposed improvement to the Mid West region's transmission network".

WP mentioned that 65MW transfer limit has been selected in 2003 on the basis of system simulation studies summarised in Appendix F of report in DMS#: 1385824 v2 with application of pole slip criteria and 10% safety margin.

Therefore recommended NCS capacity limits based on at least 50% of Walkaway's STATCOMs in service are:

- Transmission capacity of 43MW (≈ 95%[1] of 46MW)
- Local generation capacity of 84MW (based on Mungarra power station only)
- Wind generation with firm contribution of 5MW

Hence, the revised existing supply capacity in the region north of Muchea and Eneabba is approximately 132MW. This includes N-0 transmission losses of the North Country system.

[1] Operational transfer limit = 95% of calculated transfer limit as set out in the Technical Code

4.2 Addition of new gas turbine at Mungarra

Generally, additional generation in the NCS should increase the supply capacity in that region. The addition of another gas turbine at Mungarra seems is one of the options to increase generation in the NCS. Studies show that an addition of new gas turbine to Mungarra is not attractive as it seems to significantly reduce the transfer limit from ENB/MUC. Effectively the addition of this MGA GT will yield only a very small capacity increase to NCS.

The critical contingency for the above option is a fault/trip of Walkaway (WWF) to Mungarra (MGA) line which creates slow voltage recovery at Chapman 132kV bus. Similar to study results in section 4.1, the transfer limit constraint is from the TVR restriction rather than transient stability or steady state voltage limitations. The transfer limit results are shown in Table 4-3.

Table 4-3 Transfer limit at ENB/MUC with 4th gas turbine at MGA

Transfer limits at ENB/MUC in MW	
MGA Generation/Mode	No of STATCOM in service at WWF
	0
3 GT (28MW, 28MW & 28MW)	26
4 GT (10MW, 28MW, 28MW & 28MW)	< 20
4 GT (28MW, 28MW, 28MW & 28MW)	< 13

It seems that slow voltage recovery is due to the large concentration of generation at one location which has a long and weak link (low synchronising forces) with the remaining generators. This results in significant power swings for any close up fault near the generation. Also the response of the generators at MGA seems slow, probably due to slow response of the machine control systems. However it is not clear what scope there is to retune or adapt the control systems at MGA to improve their performance under these conditions. Therefore addition of another similar machine will not help the NCS situation. Note that the results shown in Table 4-1 clearly indicate that presently NCS experiences a reduction in the transfer limit when all MGA units are in service.

Therefore, we do not recommend to increase the NCS generation by adding another gas turbine at MGA or nearby substations.

4.3 Reactive support required for reinforcement option 2a

WP has considered several reinforcement options for NCS. One of the options is to erect a double circuit 132kV line from ENB to Rangeway (RAN) to establish the proposed network configuration shown in Figure 4-1.

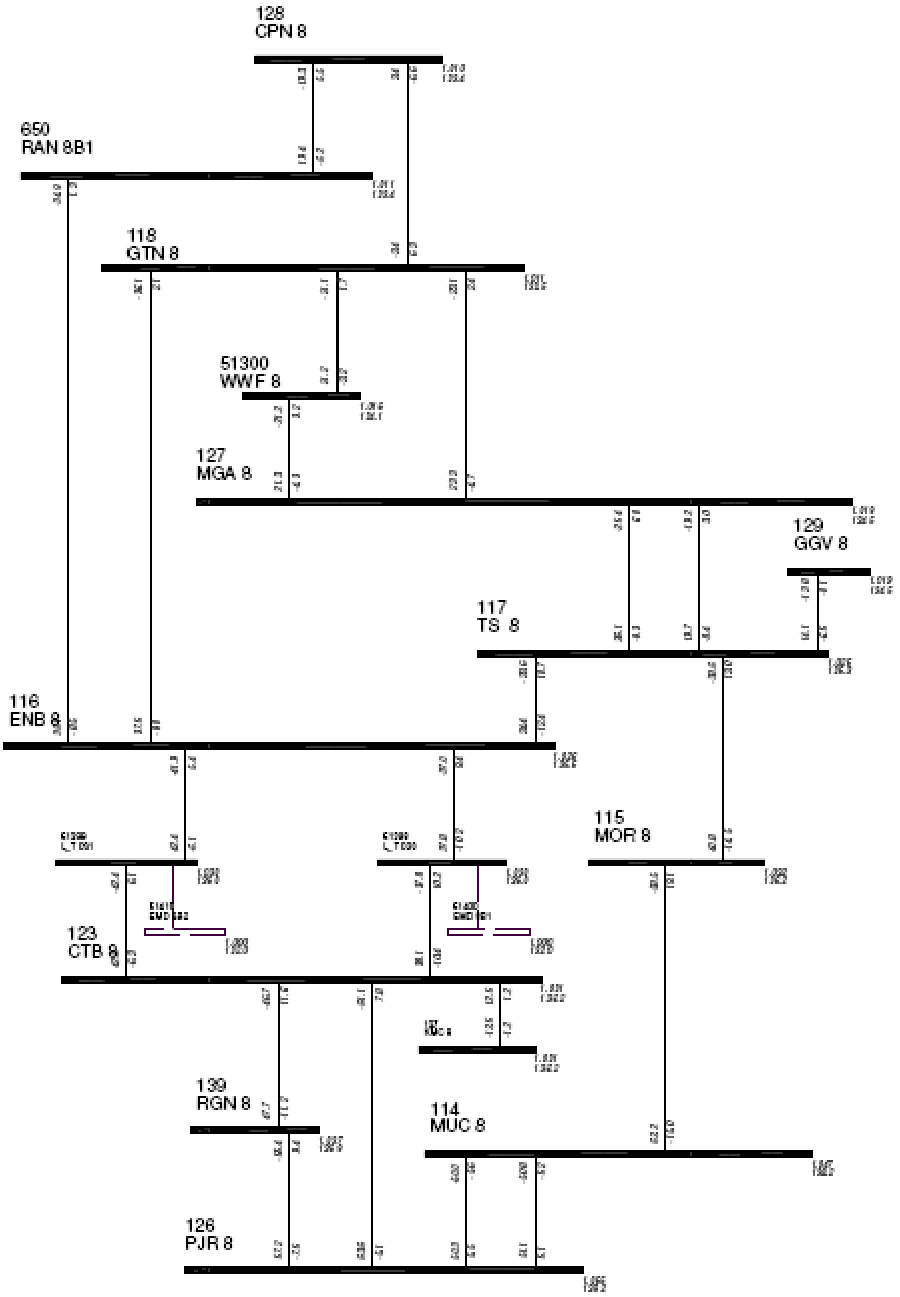

Figure 4-1 Network configuration for option 2a

Based on the studies done by Western Power, reinforcement option 2a is only a bridging solution until the year 2014. Therefore in this study the base case given by Western Power for the year 2014 is considered. Studies show that without any dynamic reactive support, option 2a may not be viable due to steady state voltage instability. Geraldton appears to be the most appropriate place to connect any reactive support device due to the large concentration of load of that area.

Based on the reactive reserve studies, an SVC and capacitor bank of 55MVAr minimum capacity is needed at the Geraldton 132kV bus in order to satisfy the zero reactive margin limits in the planning criteria. Therefore, the additional reactive support devices need to be designed such that the combination of reactive support devices can provide 55MVAr of dynamic and static reactive support even when the largest reactive support device is switched off as required by the Technical Code.

The most critical contingency for the reactive reserve calculation is the outage of the Muchea to Moora 132kV line. The reactive reserve results for the various contingencies are shown in the Figure 4-2.

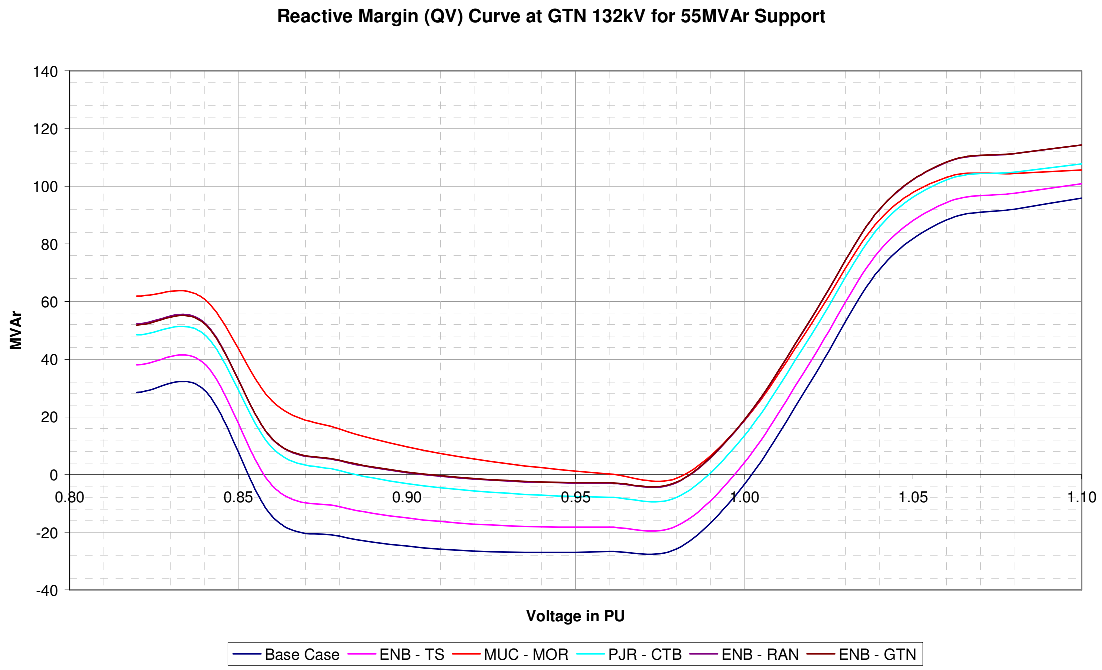

Figure 4-2 Reactive margin for contingencies with 55MVAr support at GTN

Based on the dynamic studies, the following dynamic reactive support is needed to comply with the TVR code requirement at the Chapman 132kV bus.

a. 65MVAr Static VAr Compensator (SVC); or

b. 40MVAr fixed capacitor bank with 20MVAr STATCOM

Figure 4-3 shows the voltage recovery at the Chapman 132kV for above option (b) for the MUC – MOR line fault/outage.

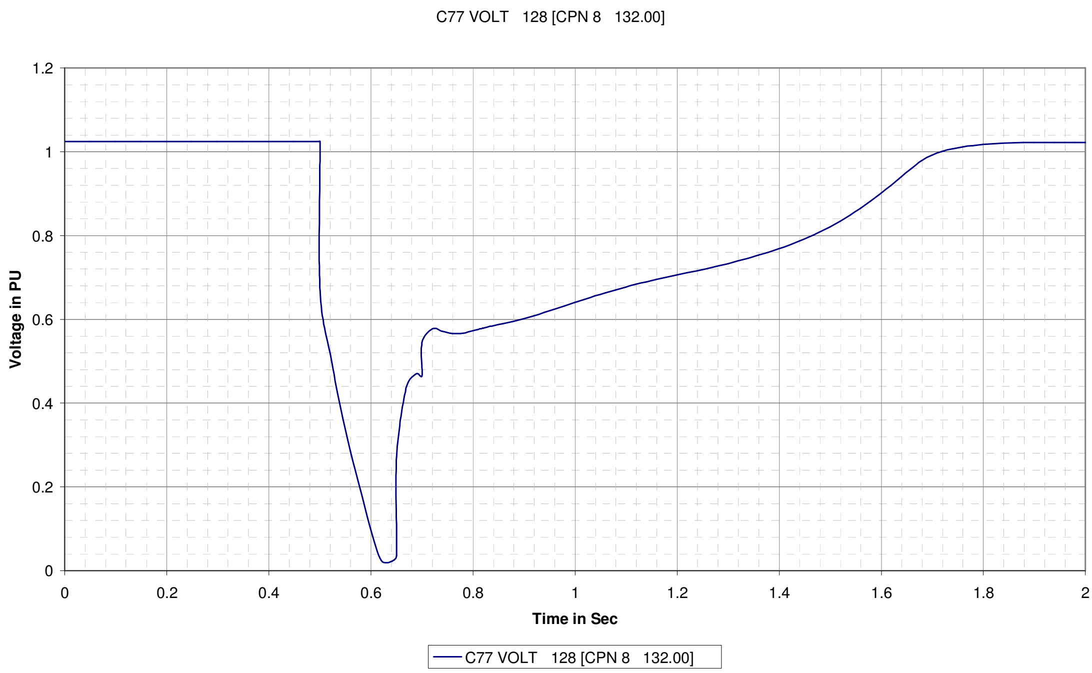

Figure 4-3 Voltage at CPN for MUC – MOR contingency

To comply with the reactive reserve and TVR requirements, a combination of fixed capacitor bank, SVC and STATCOM would be the most cost effective solution. One such combination is:

- 20MVAr STATCOM
- 30Mvar fixed capacitor bank x 2
- 10 MVAr SVC

In order to satisfy the reactive reserve criteria, the above reactive support devices need to be installed on separate circuits to cater for loss of the most critical reactive device.

Design of the reactive support device can be further optimised and it is recommended to conduct a detailed optimisation study if the reinforcement option 2a is approved to go ahead.

5. CONCLUSIONS

We can make the following preliminary conclusions and recommendations based on our assessment of the WP documents and additional simulations.

i. HTC agrees that the 46MW transfer limit, based on the TVR criteria as indicated by the "Generation requirement for North Country System in 2006 (DMS#: 2468609)", is correct and may be more appropriate than the 65MW indicated in the "Invitation for submissions – Proposed improvement to the Mid West region's transmission network". It appears that the 65MW transfer limit has been selected in 2003 on the basis of the pole slip criteria with a 10% safety margin.

ii. The appropriate existing supply capacity in the region north of Muchea and Eneabba is approximately 132MW, which consists of:

- Transmission capacity of 43MW
- Local generation capacity of 84MW (based on Mungarra power station only)
- Wind generation with firm contribution of 5MW

The above conclusion is based on at least 50% of the Walkaway wind farm's STATCOM are available.

iii. The addition of another gas turbine at Mungarra will further reduce the transfer limit from ENB/MUC due to the long and weak link between the NCS and the remaining system. Therefore, there will be no advantage to add another similar gas turbine to Mungarra power station.

iv. Reactive reserve studies show that without any dynamic reactive support, the reinforcement option 2a may not be viable due to steady state voltage instability. 55MVAr SVC and capacitor bank is required at Geraldton to meet the reactive reserve margin in the technical code. This reactive support device needs to be designed such that the combination of reactive support devices can provide 55MVAr availability where the largest reactive support device is switched off.

v. In order to comply with the TVR criterion for option 2a under the "n-1" contingency, dynamic studies show that either a 40MVAr fixed capacitor bank with a 20MVAr STATCOM or a 65MVAr SVC is required.

vi. To comply with **both** the reactive reserve and the TVR requirements, installation of 20MVAr STATCOM, 30x2 fixed capacitor banks and 10MVAr SVC is one of the viable solutions. This can be further optimised and recommend to conduct a detailed study if the reinforcement option 2a is approved to proceed

A TRANSIENT VOLTAGE RECOVERY

The Transient Voltage Recovery requirement in the Technical Code was used to determine the transfer limits. Figures A-1 and A-2 show the voltage profile and power swing from generators if all three Mungarra generators are generating 28MW each and 50% of dynamic reactive support from Walkaway wind farm is available.

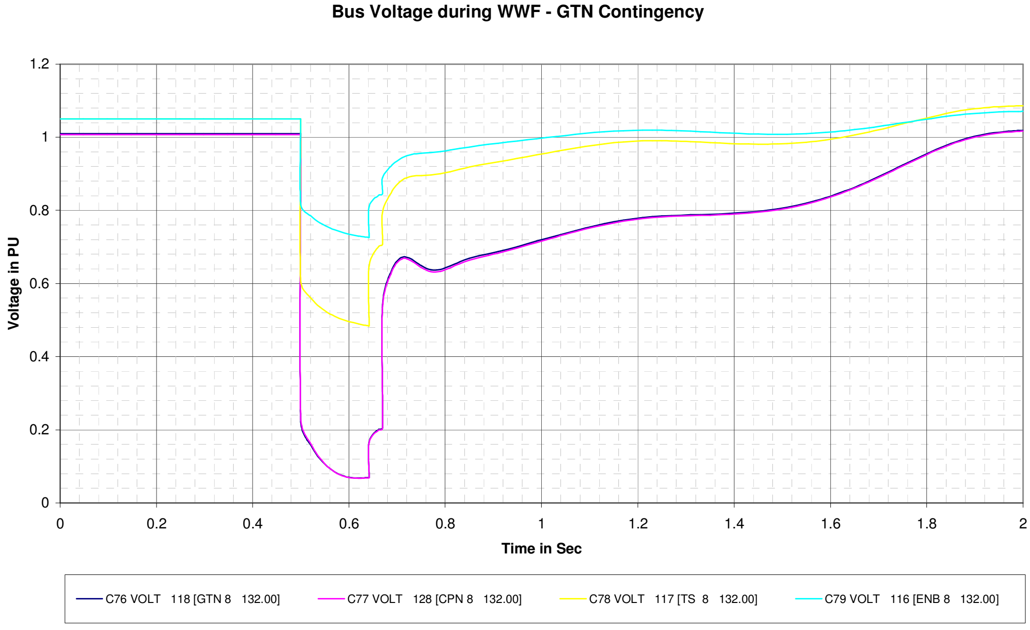

Figure A-1 Bus voltage during WWF-GTN contingency

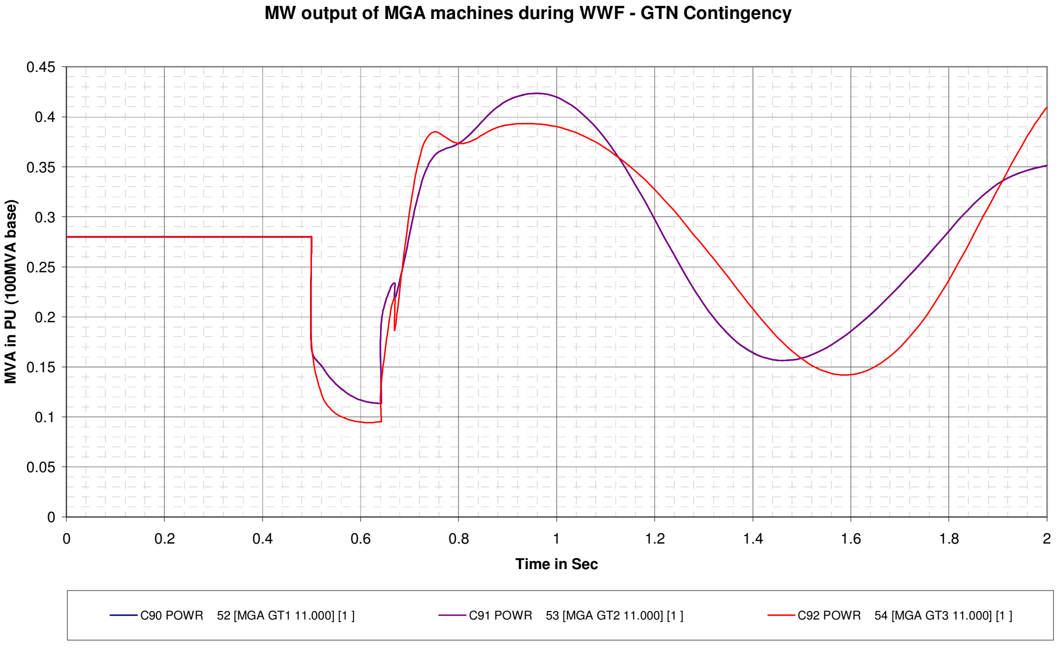

Figure A-2 MW from MGA generators during WWF-GTN contingency