FINAL REPORT V2

Prepared For:

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Reinforcement Options for the North Country Region Public Version

[Note: Correction to description of Option 10 in Table 6]

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EXECUTIVE SUMMARY

We have been retained by Western Power Corporation (Western Power) to evaluate the compliance of its preferred 330kV electricity transmission upgrade from Pinjar to Geraldton in the North Country Region (NCR) with the requirements of the Western Australian Regulatory Test. The Regulatory Test, set out in Chapter 9 of the *Electricity Networks Access Code 2004*, is an assessment of whether a proposed major augmentation to a covered network maximises the net benefit after considering alternative options, including other transmission options, generation and demand side management (DSM). Western Power can commit to the proposed augmentation if the regulator is satisfied that the Test is passed.

In this analysis we test the hypothesis that the net benefits associated with Western Power's proposed transmission augmentation option will outweigh the net benefits associated with other options involving generation, DSM and other transmission augmentations. If the benefits associated with the preferred transmission option are higher and the costs concomitantly lower, then there is a prima face case in favour of the proposed transmission option. This approach, which is a form of rank ordering, is adopted in part because the Regulatory Test requires consideration of net benefit after considering "alternative options" and does not compel all costs and benefits to be quantified.

We have considered generation and transmission options developed by Western Power, relying on Western Power's advice on technical issues. Western Power advises that generation options are not technically feasible because of synchronous stability constraints. This means that a pre-condition to connecting new generation is transmission augmentation. Load reductions that can be achieved through DSM are unlikely to be sufficient to defer capacity augmentation even under low demand scenarios. Therefore, DSM will not be viable in other (higher) demand scenarios. Furthermore, Western Power advises that single circuit 132 kV transmission augmentation options, plus the option of doing nothing, will not allow Western Power to meet technical obligations and are therefore ruled out.

The transmission augmentation options considered in detail are the following:

Table 1: Summary of transmission options considered

Option	Key features
1 (proposed)	330kV network reinforcement from Pinjar to Geraldton to be commissioned by November 2010.
1A	Staged augmentation with construction of Eneabba-Geraldton as in Option 1 but with Pinjar-Eneabba commissioned by 2014
1B	As Option 1 but with Pinjar-Eneabba delayed until 2011 and Eneabba-Geraldton by Nov 2010 initially energised at 132 kV
1C	Deferral of Option 1 by one year to Nov 2011
2A	As Option 2 but with double circuit 132kV line between Eneabba and Rangeway substation at Geraldton
4	This involves sole reliance on upgrading using 132kV lines with capacity increments by Nov 2010, 2015, 2021 and 2025
5	220kV reinforcement option by Nov 2014
6	330kV reinforcement with line towers designed for 500kV by Nov 2014
7	Bipole HV/DC reinforcement by Nov 2014

Source: Western Power

The costs and benefits of various options have been considered assuming a range of demand and discount rate scenarios. The demand scenarios considered differ in the treatment of new block loads in the NCR. All scenarios assume a common rate of growth in demand by existing customers. The high demand scenario assumes that all identified new block loads (with a total of over 300MW) will eventuate, the central demand scenario invokes a probability-weighted estimate of future load, while the low demand scenario assumes that no new block loads will eventuate. Due to potential block loads dwarfing existing demand there is a significant difference between the high and low demand scenarios. A number of energy-intensive large scale industrial developments are proposed in the NCR. For example, the Mid West Development Corporation recently concluded that the value of exports through Geraldton Port may increase seven-fold between 2006 and 2013. This is a result of an anticipated increase in the production of energy intensive products such as iron ore from facilities connected to the NCR.

Under all the demand and discount rate scenarios it is not possible to reject the hypothesis that Western Power’s proposed augmentation (Option 1) is superior to the other options. It is the lowest net present cost option under five of the six scenarios and provides greater benefit to the other options in that it:

- Provides an increase in capacity at the earliest opportunity and permits a rapid increase in demand thereafter;
- Allows the connection of new generation at an earlier date than other options;

- Facilitates entry of lower cost generation into the NCR from the SWIS (and into the SWIS from the NCR);
- Reduces transmission losses; and
- Reduces the need for ongoing reactive power support and operation and maintenance costs.

Under the low demand-high discount rate scenario Option 1A has a net present cost roughly 3% lower than Option 1. However, the net benefits of Option 1 are likely to exceed those under Option 1A under this scenario as Option 1 allows for the connection of new generation in the period 2010-14 and will have higher unserved energy benefits given the greater spare capacity.

Our results indicate that 330kV augmentation is preferable to 132kV and 220kV augmentation across all scenarios. It is also preferable to higher voltages such as 500kV, including the option of building 500kV towers, which are initially energised to 330kV. Any additional benefits of 500kV are likely to be second order if 330kV can meet all expected demand. Furthermore, if significant generation develops in the NCR, Western Power advises that a 330kV augmentation will meet voltage stability requirements even under high demand.

Therefore, we conclude that the rank ordering of net benefits supports the hypothesis that the proposed transmission augmentation Option 1 is superior to the other transmission options considered.

Western Power has also asked us to consider if the proposed augmentation meets the requirements of the New Facilities Investment Test (NFIT) in section 6.52 to 6.55 of the Access Code. The NFIT determines whether new investment can be added to Western Power's capital base. Based on the material considered we believe that the proposed augmentation option (Option 1) is also compliant with the requirements of the NFIT. It is the only option that complies with section 6.52(a) of the Test in that it can "provide for forecast sales" at the lowest cost. We also believe that it is compliant with limb 6.52(b)(i) of the Test, which requires that the incremental revenue for the new facility is expected to recover the investment cost. In addition, as the option is necessary for safety and reliability purposes to provide "contracted covered services" it is compliant with limb 6.52(b)(iii) of the Test.

1. INTRODUCTION

We have been retained by Western Power Corporation (Western Power) to evaluate the compliance of network reinforcement options in the North Country Region (NCR) with the requirements of the Western Australian Regulatory Test. The reinforcement options include Western Power's proposed 330 KV electricity transmission upgrade from Pinjar to Geraldton, other transmission options, generation and demand side management (DSM) programs.

In assessing the compliance with the Regulatory Test, we have considered Western Power's proposed transmission augmentation and alternative transmission options under various scenarios relating to demand and market outcomes to assess whether there is a dominant transmission augmentation strategy that satisfies the Regulatory Test.

This report is a high-level review of Western Power's options and basic supporting data to assess whether the proposed option complies with the requirements in the Regulatory Test. The review is not intended to include specific quantification of all costs and benefits. This is because such quantification is not essential to establish of the dominance of the preferred option in relative terms among the proposed alternatives, including "do-nothing".

A list of documents that we have considered in developing this review is set out in Appendix A:

1.1. THE REGULATORY TEST

The Regulatory Test for the electricity sector in Western Australia has not been applied prior to this case. It was created upon introduction of the Electricity Networks Access Code 2004 (Access Code) under the Electricity Industry Act 2004.[1] The Regulatory Test is an assessment of whether a proposed major augmentation to a covered network maximises the net benefit after considering alternative options.

Under Section 9.14 of the Access Code, the Regulatory test is met if the Regulator is satisfied that:

1. the service provider's statement that the proposed augmentation "maximises the net benefit after considering alternative options" is defensible; and

2. the service provider has applied the regulatory test properly to each proposed major augmentation:

   - using reasonable market development scenarios which incorporate varying levels of demand growth at relevant places; and

1 See Western Australian Government Gazette, 30 November 2004, No 205. The Electricity Networks Access Code has subsequently been modified subject to revisions included in the Western Australian Government Gazette, 1 September 2006, No 152.

- using reasonable timings, and testing alternative timings, for project commissioning dates and construction timetables for the major augmentation and for alternative options;

Note that under section 9.23 of the Access Code the Regulator may waive or expedite the application of the Regulatory Test to the extent that it considers application would be contrary to the Chapter 9 rules including because:

1. there are no, or it is unlikely that there are any, viable alternative options to the proposed major augmentation; or

2. the nature of the proposed major augmentation is such that significant advance planning is required and no alternative options exist; or

3. the nature of the proposed major augmentation, or part of it, is such that it should be submitted to the Independent Market Operator established under the Electricity Industry (Independent Market Operator) Regulations 2004, or

4. the nature of the funding of the proposed major augmentation means that the proposed major augmentation will not cause a net cost (measured in present value terms to the extent that it is possible to do so) to those who generate, transport and consume electricity in the covered network and any interconnected system.

We believe that the requirement for demonstrating maximum net benefit can be met by providing a robust rank-ordering of alternatives, even if the absolute net benefit levels are not specifically quantified. In other words, if a transmission augmentation option can be shown to have superior net benefits to all other viable options (including the option of doing nothing), it should not be necessary to quantify the net benefits in absolute (dollar) terms to meet the requirements of the Regulatory Test.

1.2. Outline of the Report

This report is structured as follows:

- Section 2 considers trends in demand for and supply of energy in the NCR and the necessity of augmentation;

- Section 3 sets out the methodology employed in assessing Western Power’s proposed augmentation;

- Section 4 considers options and scenarios modelled;

- Section 5 evaluates the options under each of the scenarios; and

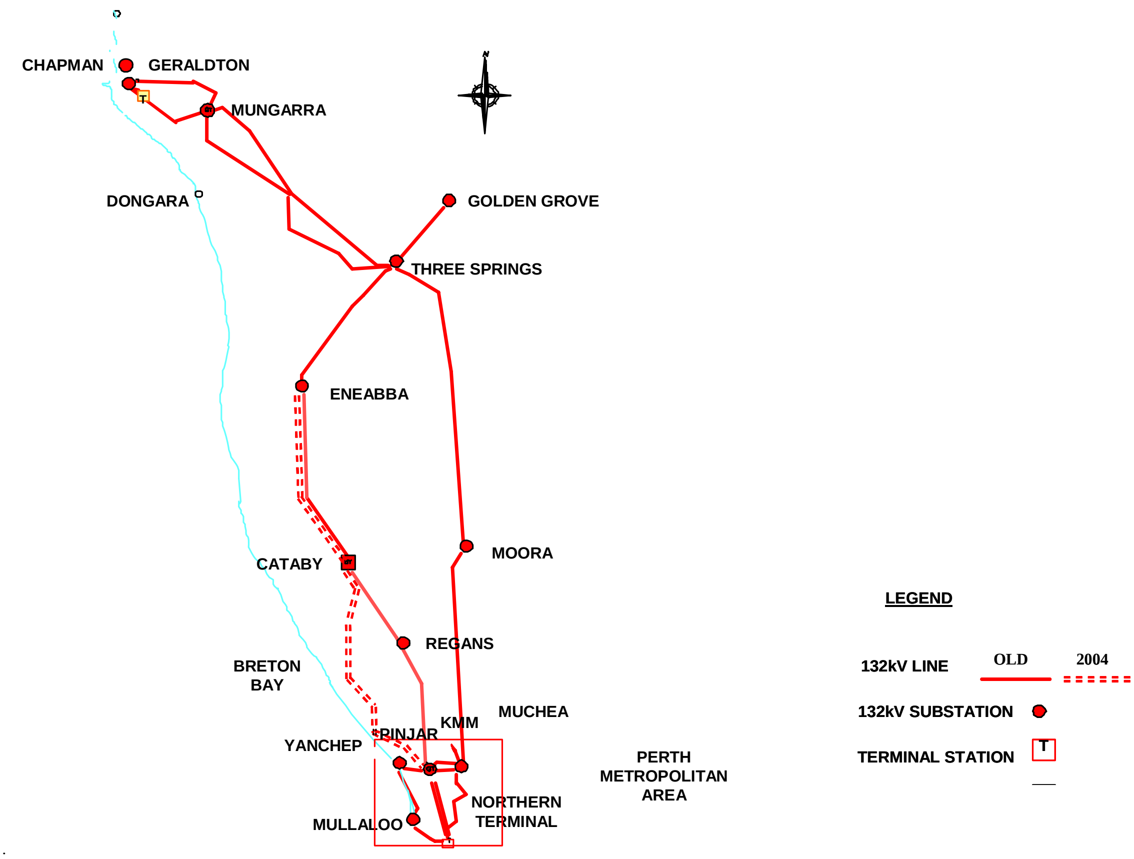
- Section 6 sets out our conclusions.

2. NORTH COUNTRY REGION SUPPLY-DEMAND SITUATION

2.1. OVERVIEW OF THE NORTH COUNTRY REGION NETWORK

The NCR transmission network extends from Pinjar and Muchea in the south up to Geraldton and Chapman in the North. It consists of a series of 132kV transmission lines and extends approximately 400km in length from its Southern to Northern extremities. There are 9 zone substations in the NCR as indicated in the figure below.

Figure 1: Overview of North Country Region



Source: Western Power Corporation, Major Supply Options for North Country Region of Western Australia, Dms-3339124v4, December 2006.

The most recent augmentation in the NCR was construction of a 132kV line from Pinjar to Eneabba via Cataby. This line was commissioned in 2004.

There are five main sources of generation in the NCR:

- The Mungarra power station, which is owned by Verve Energy, is connected to the 132kV system approximately 40km south of Geraldton. The plant consists of three Frame 6 gas turbines and provides voltage support to enable the local transmission network to meet demand in excess of the transmission transfer limits that would otherwise apply: this function results in the local network being able to supply up to 84MW additional capacity in summer;

- The Geraldton power station is connected to the 33kV system at Geraldton and consists of a 20MW gas turbine. This unit provides an alternative supply during system emergencies and provides additional generation during system peaks. However, this generator is rarely used because its operation produces high noise levels causing disturbance to adjacent houses. It is also costly to operate as it runs on distillate;[2]

- The Walkaway Wind Farm (WWF), located close to Geraldton was commissioned in 2005 and has notional capacity of 90MW. However, the wind farm's contribution to peak summer capacity may be significantly lower than this notional capacity, as the power output will be a function of prevailing winds. Based on data from South Australian wind farms, Western Power estimates that the WWF can provide approximately 5MW of firm peak capacity;

- The Emu Downs Wind Farm, located close to Cataby was commissioned in 2006 and has notional capacity of 80MW;[3] and

- Remaining power requirements are supplied from the South West Interconnected System (SWIS) and are transported to the NCR via Pinjar and Muchea.

The region encompassed by the NCR network is sparsely populated. Total diversifiable peak load (without losses) at the nine substations in the NCR was approximately 140MW in 2005, with around one-third of this load accounted for by three major mines at Cataby, Eneabba and Golden Grove as set out in Table 2.

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2 Verve Energy is obligated to maintain capacity at the Mungarra power station and the Geraldton Gas Turbines until October 2009 and provide synchronous compensator capability until June 2011.

3 The contribution to peak capacity will be reduced from the notional capacity in a similar manner to the WWF. Note that this generator is not located in the critical area north of Eneabba and Muchea, which is the focus for much of the subsequent analysis in this report.

Table 2: Summer diversified peak load NCR 2005

Substation	Peak (MW)	Type of customer
Geraldton 33 kV	34.4	Industrial, rural, residential
Durlacher	24.4	CBD, residential, commercial
Eneabba	21.5	Mining
Cataby	12.3	Mining
Golden Grove	12.1	Mining
Moora	11.1	Rural
Chapman	10.4	Residential, commercial
Regans 33/22 kV	7.7	Rural
Three Springs	6.5	Rural
TOTAL	140.4	

Source: Western Power

2.2. Constraints

Western Power has identified a range of constraints on the network:

- The length of the transmission line results in significant drop in voltage, especially at the extremity of the line at Geraldton and significantly affects the transfer capability of the network.[4] The import capability into the NCR depends on a number of factors including: the local generation, availability of local dynamic reactive power source and regional load (north of Eneabba and Muchea). Studies undertaken by Western Power show that the import capability can be as low as 43 MW without the Mungarra generators in operation and up to 73 MW with 3 Gas Turbines at Mungarra in operation;[5]

4 Western Power Corporation, 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-3339124v4, December 2006, Table 4, page 18, which refers to the Westinghouse Electrical T&D Reference Book and notes that the Surge Impedance Loading (SIL) of a 400 km long 132kV line is only 43 MW (SIL is a broad indicator of the underlying transfer capability of a transmission line)

5 Western Power Corporation, *Generation Requirement in North Country Region*, Study Note SN 834, Table 4.5A.

- Loading in the NCR is approaching the point where there will be a risk of complete shutdown of the NCR due to voltage collapse. Western Power reports that if imports into the NCR exceed 80MW even while the Mungarra units are operating, loss of a line between Eneabba/Muchea and Three Springs might result in voltage collapse.[6] In addition, Transient Voltage Recovery (TVR) standards may be not be met;

- If existing lines are run at excessive currents (as is typically the case at high loads) thermal limits will be reached, which can result in conductor sagging creating a public safety risk; and

- A number of the existing lines were constructed without overhead earths and results in lightening induced faults causing interruptions to those lines. Western Power estimates that there are approximately 52 such faults per year between Geraldton and Perth.

The NCR is significantly capacity constrained. Western Power advises that construction of the 132kV line from Pinjar to Eneabba in 2004 temporarily eased some of the constraints on that line section. However, the recent connection of the Emu Downs Wind Farm near Cataby has exhausted transmission capacity available to connect new generation in the area between Pinjar and Eneabba. Furthermore, supply augmentation is especially critical on the Eneabba-Three Springs, the Muchea to Three Springs and the Three Springs-Geraldton sections of the network. These constraints in the Northern part of the NCR are the principle focus of the remainder of this paper.

2.3. Need for Reinforcement in the North Country Region

The need for reinforcement in the NCR is driven by currently expected trends in demand and supply.

2.3.1. Demand outlook

Western Power has characterised its demand outlook as comprising two distinct sets of load:

- "Natural" load growth consisting of growth from existing customers plus smaller new loads that Western Power has agreed to connect where there is sufficient transmission capacity; and

- "Block" loads, consisting of major new industrial developments for which major connection agreements (including dedicated assets) will need to be negotiated on a case-by-case basis.

6 *Ibid,* page 5

The forecast for “natural” load growth developed by Western Power includes allowance for connection of some small customers in the period up to 2010. After 2010 peak demand growth at a substation level is forecast to grow at an annual rate of between zero and 3.5%, with average growth approximately 2.6%. This is a relatively conservative forecast when considered against recent trends. For example, Western Power estimates that (natural) load growth at Geraldton has averaged around 6% per annum over the period 2000-06, while (natural) load growth for the area north of Eneabba and Muchea has averaged around 4.6% per annum between 1998 and 2006.

In addition, Western Power has identified a number of potential block loads, as set out in Table 3.

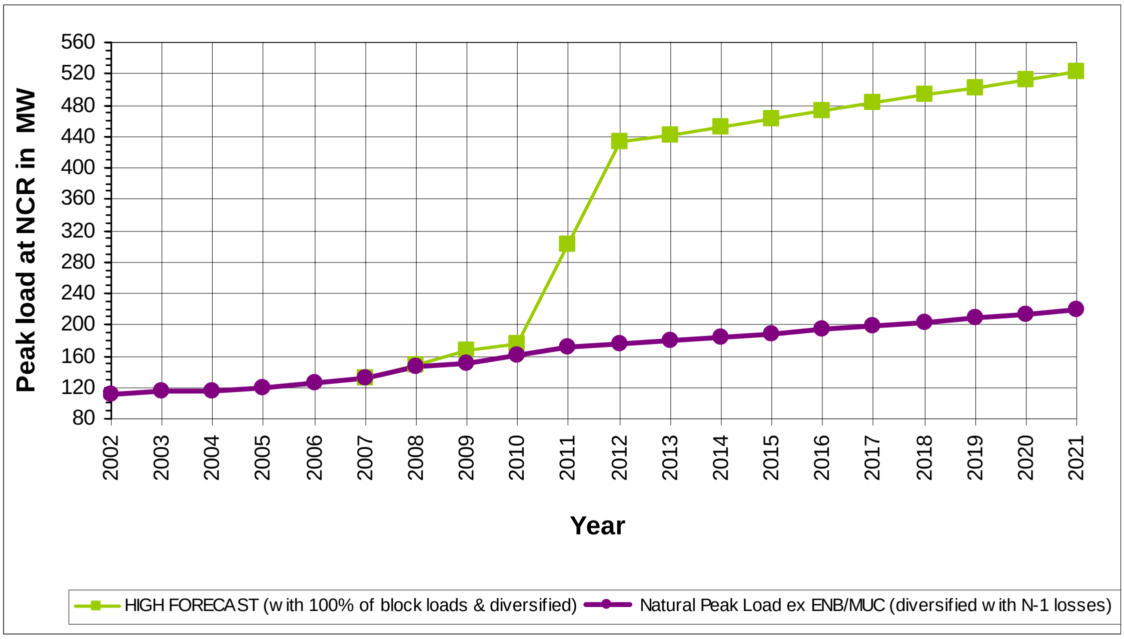
Table 3: Potential new block loads

Development	Potential Load (MW)	Expected date of commissioning
Gindalbie Metals Ltd: Karara Iron Ore	130	2011
Gindalbie Metals Ltd: Dandaragan pumps	7	2011
Mt Gibson Iron: Victol Metallised Iron	12	2011
Mid-West Corp: Pig Iron Plant	60	2012
Mid-West Corp: Oakajee	40	2012
Mid-West Corp: Koolanooka & Mt Gibson (Perenjori)	50	2012
Aviva Corp: Eneabba Coal Mine	15	2011
TOTAL	**314**	

Source: Western Power

The scale of the potential load growth is so significant as to dwarf all existing load on the NCR network. Figure 2 illustrates the load forecasts based on two scenarios: “natural” growth, and natural growth plus all new potential block loads.

Figure 2: Forecasts for peak load in NCR (diversified with N-1 losses and north of Eneabba and Muchea) based on natural load with and without all block loads



There is an element of circularity in evaluating the "firmness" of some of the potential block loads. The ability of Western Power to sign connection agreements with interested parties is limited by the availability of capacity on the transmission network, while the viability of some of the proposed industrial developments is a function of the availability of sufficient network capacity. Nevertheless, there is a range of evidence to support the firmness of some of the proposed new block loads.

The Mid West Development Corporation[7] (MWDC) publication "Major Projects Update (July 2006)" highlights a number of potential projects in the NCR with energy requirements, including those listed in Table 3 above. The MWDC concludes that the extent of development proposed in the region around Geraldton is significant and on a scale that the value of exports through Geraldton port (largely a result of energy intensive products such as iron ore) may increase seven-fold by 2013:

PROPOSED PROJECTS - IRON ORE IS THE MAJOR COMMODITY

- *Eight (8) companies with twelve (12) projects;*
- *Four (4) are short term (< 10 years);*

7 The Mid West Development Commission is a Western Australian statutory authority whose main aim is to encourage and promote the sustainable development of Western Australia's Mid West region. The Mid West Development Commission is one of nine Regional Development Commissions and is responsible to the Minister of Agriculture and Forestry. For further details see: www.mwdc.wa.gov.au

- *Eight (8) are long term (20 years);*
- *Two (2) of the long term projects are evaluating expansion programs;*
- *Four (4) of the long term projects involve / are evaluating value adding;*
- *One (1) project is scheduled to commence in the second half of 2006;*
- *Three (3) projects are planned to start exporting in 2007;*
- *Construction of one major project is planned to start in 2007 / 08;*
- *Collective capital of all projects is between $4.5 & $6 billion, dependant on expansion programs;*
- *Estimated construction employment of between 4,000 & 6,000 dependant on expansion programs;*
- *Estimated permanent employment of between 2,000 & 2,500, dependant on expansion programs;*
- *A number of these are in the very early stage of planning and have a long way to go;*
- *These numbers are direct employment only;*
- *No allowance made for the multiplier effect.*

OTHER PROJECTS NEARING DEVELOPMENT:

- *Six (6) companies with six (6) projects;*
- *A mix of long term (20 years), medium term (10 – 20 years) and short term projects (<10 years);*
- *All are likely to commence in 2007;*
- *Commodities include: Mineral Sands, Vanadium, Gold & Copper*

In 2004, exports through the Geraldton Port Authority totalled 4M tons with a value of approximately $1 BN. Included in this were exports of approximately 1.3 MT of iron ore.

Based on the combined project concepts, exports of iron ore products (Hematite, Magnetite Concentrate, Pellets etc) could be around 80 mtpa by 2013 and will be valued at approximately $7 billion per annum based on today's prices.

The expectation of energy-intensive industrial development resulting in increased export volumes is also reflected in the State Government announcing the development of Oakajee (north of Geraldton) as a deep water port:[8]

> *Premier Alan Carpenter has today confirmed Oakajee as the preferred site for a new privately funded deep-water port.*
>
> *Mr Carpenter said the development of Oakajee, which was about 20km north of Geraldton, would support the expansion of iron ore mining in the Mid-West region.*
>
> *The Premier said work completed by the Mid West Development Commission showed that a number of major resource development projects in the State's Mid-West could generate up to 60 million tonnes per annum (Mtpa) of iron ore for export by 2012.*
>
> *"With the scale of iron ore mining proposals which are emerging in the Mid-West region, the expansion of Geraldton Port's export capacity beyond approximately 20Mpta would be unacceptable from both social and environmental perspectives," he said.*
>
> *"The two ports will complement each other and both will come under the jurisdiction of the Geraldton Port Authority.*

There is also evidence that many of the specific block loads identified by Western Power are firm in nature. For example, Gindalbie Metals has announced to the Australian Stock Exchange firm agreements to sell iron ore from its Karara project in the Mid West region to a dedicated plant to be constructed in China by 2008:[9]

> *Gindalbie Metals Ltd (ASX: GBG) and its joint venture partner, Anshan Iron and Steel Group ('AnSteel'), today announced that they had agreed on a joint proposal to locate the 4mt/annum Pellet Plant for the Karara Iron Ore Project adjacent to a major new steel mill to be constructed by AnSteel in north-eastern China.*
>
> *AnSteel has earmarked a site for the new Pellet Plant, which would be owned on a 50:50 basis by the joint venture partners, in the port city of Yingkou in north-eastern China, 1km from a major new 5 million tonne per annum steel mill due for completion in 2008. The Karara Joint Venture Pellet Plant will meet a substantial proportion of AnSteel's new steel mill input requirements.*
>
> *The agreement further enhances the strong relationship between Gindalbie and AnSteel which is underpinned by the joint venture agreement signed on 3 April this year in Canberra for development and financing of the Karara Iron Ore Project in Western Australia's Mid West region. The Karara Project is a major new iron ore development project, with targeted production of 10mt/annum of iron products including hematite, magnetite concentrate and pellets.*

8 "Oakajee confirmed as preferred private port site", Media Statement, Alan Carpenter MLA, 19 April 2006.

9 Gindalbie Metals, Stock Exchange Announcement, 13 September 2006, "Gindalbie and Ansteel announce landmark agreement to locate Karara Pellet Plant in Northeast China". http://www.gindalbie.com.au/files/ASX_Release-57-060912_Landmark_Agreement_to_locate_Pellet_Plant_FINAL.pdf (accessed 29 December 2006).

Furthermore, Gindalbie Metals has announced the signing of a Memorandum of Understanding to reserve port capacity at Geraldton for sale of the iron ore products:[10]

> *The Board of Gindalbie Metals Ltd (ASX Code: GBG) is pleased to announce that it has signed two Memoranda of Understanding (MOU) with the Geraldton Port Authority ("GPA") on behalf of the Karara Iron Ore joint venture participants for access to suitable storage and loading facilities at Berth 5 and Berth 7 at the Geraldton Port for the export of iron products from its Karara Iron Ore Project in Western Australia.*
>
> *The MOU's were signed in the presence of representatives of Gindalbie's Joint Venture Partner, Anshan Iron & Steel Group Corporation (Ansteel), China's second largest steel producer.*
>
> *Under the MOU's, Gindalbie and the GPA have agreed to work together to complete formal documentation for the lease of space at Berth 5 for the storage and shipment of up to 4mtpa of hematite ore and at Berth 7 for the storage and shipment of up to 8mpta of magnetite ore. The parties will also complete documentation in respect to provision of Port Services by the GPA.*
>
> *The MOU in respect to Berth 5 also envisages Gindalbie providing a throughput guarantee of 1.5 million tonnes per year for a period of 10 years commencing from the time first delivery of hematite to the Port occurs. Any shortfall on the throughput guarantee will require a payment of $2 per tonne of ore by Gindalbie to the GPA. No throughput guarantees are required in relation to Berth 7.*

2.3.2. Supply outlook

Western Power estimates that existing supply capacity in the region north of Muchea and Eneabba is approximately 155 MW. This assumes roughly:

- Transmission capacity of 65MW;
- Local generation capacity of 85MW – based on Mungarra Power Station only; and
- Wind generation of 5MW.

If Western Power seeks a generation option for the post-October 2009 period it needs to inform the Independent Market Operator (IMO) who will then issue a request for tender to provide generation services.

There is a range of economic and technical uncertainties surrounding any tender arrangement:

10 Gindalbie Metals Stock Exchange Announcement 20 November 2006, "Gindalbie Signs Two MOU's with Geraldton Port Authority for Karara Iron Ore Project", http://www.gindalbie.com.au/files/ASX_Release-68-061117_MOU_Signed_with_GPA.pdf (accessed 29 December 2006)

- Both Mungarra and Geraldton are high operating cost plants, which reflect age and being run for purposes other than those the plants were initially designed for. The Mungarra plant has been run at a level significantly higher than intended due to voltage stability issues in the NCR and due to shortage of the transmission capacity;

- The Geraldton plant is a 30-year old Frame 5 diesel generator that can be rarely used due to close proximity to residential development;

- Both plants will require significant maintenance. However, the incentive for Verve Energy to undertake such maintenance will depend on the likelihood of the generators subsequently becoming stranded. As they have high cost they will not be called to supply load if the transmission line is subsequently augmented and cheaper sources of electricity become available;

- Western Power may be obligated to pay all out-of-merit costs associated with operating these plants to meet load demand. The cost of doing so is significant. For example Western Power estimates that by 2009 out-of-merit costs will be between $2 million and $6 million per annum depending on transfer limits that determine the requirement of expensive local generation;[11]

- Without the ability to call on generators like Mungarra and Geraldton (which may not be available beyond October 2009), and in the absence of any agreement and augmentation of the network, Western Power will need to install Static VAR compensation (SVC) to maintain reactive support. Western Power estimates the capital cost of providing SVC equivalent to any lost generation support at Mungarra as $30m; and

- The potential for new entry is limited due to the tight capacity in the network, which renders any dedicated assets liable to subsequent stranding.

Western Power has received proposals for new sources of generation on its network, which include:

- Wind farms at Mumbida, Coronation Beach, San Angelo, Cowalla Hill, Moresby Range and Walkaway (II);

- The Centauri I gas fired plant at Dongara proposed by Eneabba Gas; and

- A coal fired plant at Eneabba proposed by AVIVA.

The potential generating capacity of these plants are summarised in Table 4.

11 The estimate of $2 million assumes 95.8MW transfer capacity (transmission plus Walkaway Wind Farm) while the estimate of $6 million assumes 59MW transfer capacity (transmission without Walkaway Wind Farm and STATCOM).

Table 4: Potential new generation options

Development	Generating Capacity (MW)	Potential supply date
Conventional fuel generators		
Centauri I PS (Dongara) – Eneabba Gas	168	2008
AVIVA coal fuelled PS (Eneabba)	400	2011
Dongara Gas Turbines	80	Dormant
Wind farms		
Mumbida ,	30	Dormant
Coronation Beach	10	Dormant
San Angelo	50	Dormant
Cowalla Hill	100	Dormant
Moresby Range	12	Dormant
Walkaway 2	90	Dormant

Source: Western Power. Note that the capacity of wind farms is notional capacity and does not equate to firm capacity to meet peak demands. Details of the proponents of the wind farms are held by the Open Access branch of Western Power.

Western Power advises that it is unable to connect any of these developments due to constraints on the current network. Those developments marked as “dormant” are ones where Western Power is unable to proceed the processing of those applications for connection due to insufficient network capacity.

There is evidence that many of the proposed generation loads are increasingly firm in nature. For example, Eneabba Gas has issued a range of public announcements in relation to its proposed Centauri power station. These relate to the purchase of land for the power station,[12] signing a Memorandum of Understanding with Verve Energy for use of North West Shelf Gas supplies,[13] and making arrangements for the use of coal seam methane in the plant.[14] In addition, in October 2006 ERM Power and AVIVA Corporation announced a joint Pre-Feasibility Study on a 400MW base-load power station near Eneabba.[15] Furthermore, the fact that a number of Windfarm developments are marked as "dormant" implies that many of these proposals may already have been in place, had sufficient transmission capacity been available.

The lack of network capacity and requirement for reactive support mean that without any network augmentation, Western Power estimates that supply capacity will remain around 155MW for the foreseeable future.[16]

2.3.3. Supply-demand situation

Assuming supply availability around current levels, the supply-demand situation will gradually deteriorate as a result of demand growth. Western Power estimates that by 2009/10 expected demand will exceed expected capacity availability, considering only natural growth. New block loads could potentially dwarf current levels of demand.

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12 In the Eneabba Gas Annual Report 2006, p.3, the Chairman of Eneabba Gas, Reg Gillard notes that "the Company has acquired a strategically important site near Dongara (near the port city of Geraldton and approximately 380 km north of Perth), on which to locate the power station. The site is close to the APT Parmelia gas pipeline and to the regional electricity grid for the North Country region, which is of critical importance in ensuring gas supply for the operation of the turbines and then being able to sell the resultant power into the grid system."

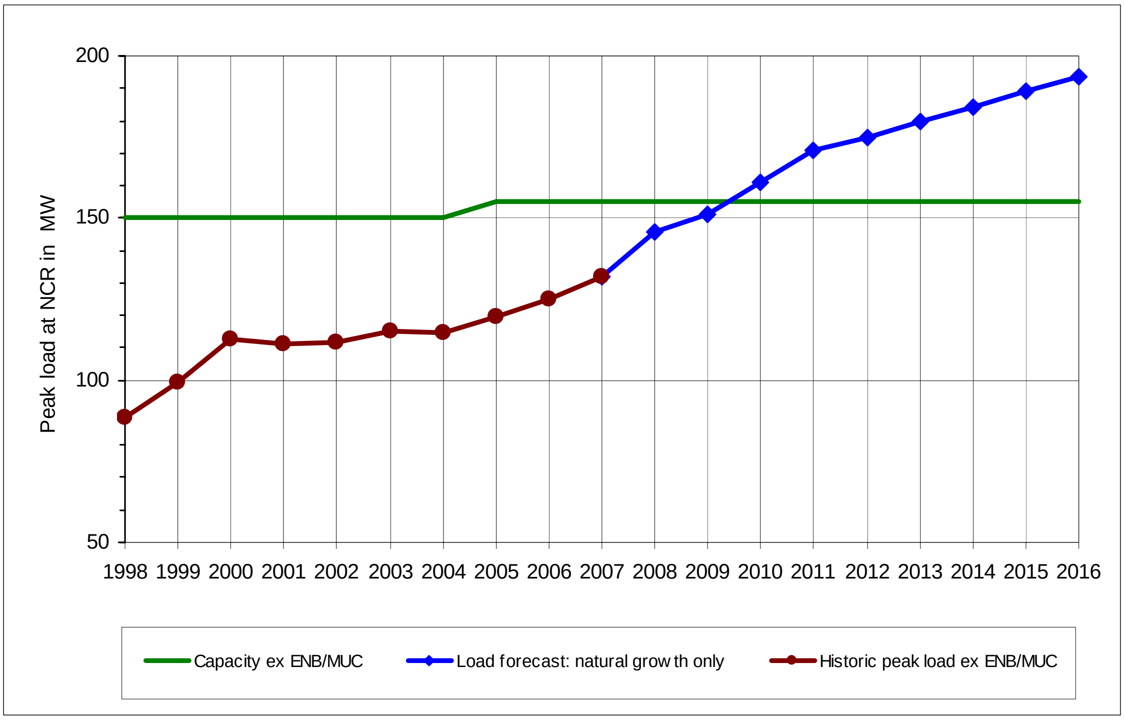
13 Eneabba Gas Limited ASX Release, 23 October 2006, "Eneabba Gas Arranges MoU with Verve Energy, http://www.asx.com.au/asxpdf/20061023/pdf/3z3wtbsb817f0.pdf (accessed 29 December 2006).

14 Eneabba Gas Limited ASX Release, 9 November 2006, "Eneabba Gas Acquires 70% Interest in Proposed Greenough Block", http://www.asx.com.au/asxpdf/20061109/pdf/3zhph1bmt500w.pdf (accessed 29 December 2006).

15 ERM Power and Aviva Corporation Limited Joint ASX and Media Announcement, 3 October 2006 "Major Energy Player Partners with AVIVA to Develop Mid West Power Station" http://avivacorp.com.au/releases/379668.pdf (accessed 29 December 2006).

16 The firm capacity estimate of 155 MW in the NCR regions includes 3 Gas Turbines and 5 MW firm capacity contribution from Walkway wind-farm. Western Power projects the firm capacity to remain at 155 MW until major power supply reinforcement is delivered (Western Power Corporation, 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-3339124v4, December 2006, page 64).

Figure 3: Supply-demand situation based on natural load growth 1997/98 to 2015/16



Source: Western Power.

3. METHODOLOGY FOR ASSESSING AUGMENTATION OPTIONS

3.1. REGULATORY TEST REQUIREMENTS

The Regulatory Test considers whether a proposed major transmission augmentation maximises the "net benefit after considering alternative options" (section 9.3). The "net benefit after considering alternative options" means a net benefit to those who generate, transport and consume electricity in the covered network and any interconnected system, having regard to all reasonable alternative options, including the likelihood of each alternative option occurring (section 9.4).

This means that any assessment of a proposed augmentation needs to consider:

- The "net benefits" to those who generate, transport and consumer electricity; and
- "Reasonable alternative options", including the likelihood of each alternative option arising

3.1.1. Net benefits

A net benefit of an augmentation option can be generically defined as follows:

Net benefit = Benefit – Cost of the augmentation option

The benefits can include a range of factors, including:

- **System capital cost** savings, which arise from the ability of the transmission project to defer/avoid building peaking generation capacity;
- **Operating cost** savings, which capture the ability of the transmission project to displace generation from high cost plants; and
- **Unserved energy cost** savings, which arise from the improved reliability of the system.

While usually construed as the value of avoided service disruptions of connected loads, the unserved energy cost savings could be construed more broadly to include the effect of augmentation to facilitate the connection of new loads and generation.

The cost of augmentation options can usually be estimated using engineering analysis. Where benefits and costs can be estimated quantitatively they will need to be considered in net present value terms. This point is especially relevant for transmission investments given that they involve periodic renewal over time and may result in costs that vary over time. The need to evaluate costs and/or benefits in net present value terms requires estimation of a discount rate (which is discussed in section 4.2.2 below).

3.1.2. Reasonable alternative options

The Regulatory Test defines alternative options to a major augmentation to mean “alternatives to part or all of the major augmentation, including demand-side management and generation solutions (such as distributed generation), either instead of or in combination with network augmentation”. For the purpose of our analysis we have assumed that this means variants on the major augmentation proposal in terms of sizing and timing should be considered.

Section 9.4 of the Access Code also requires consideration to be taken to the “likelihood of each alternative option proceeding”. We have assumed that this requires consideration of:

- Technical constraints that may affect the feasibility of a particular project; and
- Planning issues that may result in deferral of project timings relative to what is technically possible.

3.2. HYPOTHESIS TO BE TESTED

In this analysis we test the hypothesis that the net benefits associated with Western Power’s proposed transmission augmentation option will outweigh the net benefits associated with generation, demand management and other transmission augmentation options. If the benefits associated with the preferred transmission option are necessarily higher and the costs concomitantly lower, then there is a prima face case in favour of the proposed transmission option.

This approach, which is a form of rank ordering, is adopted in part because the Regulatory Test requires consideration of net benefit after considering “alternative options” and does not compel all net benefits to be quantified.

If there is no clear dominance among the options, a detailed examination of the components of benefits will be necessary. In particular, there may be trade off among the components of benefits or trade off between benefits and costs. In such a case there may be need for assessment of the plausibility of conditions (if any) that would result in a change in option rankings.

An examination of various market development scenarios is also required to assess whether the rank order of options is sensitive to the choice of scenario on issues such as demand growth and the discount rate.

The above approach to modelling net benefits will be applied to those projects that are technically feasible. These are those that render the system secure.

3.2.1. Rationale for a rank ordering approach

We undertake a rank ordering approach primarily because we envisage fewer trade-offs between options in the NCR than in other settings where a similar Regulatory Test has been conducted, including the Australian National Electricity Market (NEM) and New Zealand.

Trade-offs between options are most likely to arise where there are meshed networks, generation investment can be deferred and hybrid options are feasible. These issues make it more difficult to establish a robust rank-ordering of alternatives—not least because the alternatives are so numerous. However, key features of the NCR – in particular the radial nature of the network and the long distances over which electricity is transported – simplify the assessment of trade-offs:

- Many areas of the network are only supplied by one transmission line, limiting the ability of the network to cope with a single contingency (the N-1 criterion). This feature restricts the feasible options; and

- Transporting energy over long distances results in an increasing need for voltage support. However, for generation to perform this role there needs to be sufficient capacity in the network to support its connection. Therefore, options such as increasing generation in a radial network may require simultaneous capacity expansion to be economic. When generation and transmission investments are complementary, it does not make sense to treat them as substitutes in the cost-benefit framework.

There is an apparent presumption in the regulatory test that a particular investment is contemplated in a situation of exogenous demand growth. When the investment itself may significantly influence future patterns of demand growth – as is likely the case with transmission augmentation in the NCR – it complicates the analysis of options because the demand forecast becomes endogenous to the augmentation project. It also means that certain benefits to those that generate, transport or consume electricity can only occur with system augmentation. This represents an important difference from the use of regulatory test formulations in assessing interconnection projects as has been typical in the NEM and in New Zealand.

4. OPTIONS AND SCENARIOS

This section outlines the alternative options that Western Power has considered and various scenarios that have been run.

4.1. OPTIONS

As required under the Access Code,[17] Western Power has considered a range of transmission, generation and demand side management alternatives. The costs and net benefits are considered only when key technical constraints[18] and access requirements are met. These include the requirements to:

- Maintain system stability. Under the Transmission Network Planning Criteria the network must be capable of withstanding the loss of any single network element such as a transmission line or transformer at any load level and for any generation schedule (N-1 requirement); and
- Use all reasonable endeavours to provide access to covered services (sections 2.7 and 2.8 of the Access Code), which means any feasible option must provide a reasonable expectation of meeting expected demand.

4.1.1. Transmission augmentation options

Table 5 sets out the transmission augmentation options considered by Western Power and details on the required capital expenditure. Note that the options assume near-term capital expenditure on Static VAR compensation (SVC) where the project is delayed beyond 2010, when the VAR compensation provided by the Mungarra and Geraldton power stations may no longer be available.

17 Under the Access Code “alternative options” are defined to include “demand-side management and generation solutions (such as distributed generation), either instead of or in combination with network augmentation.

18 For the purpose of this assessment, compliance against the Draft Technical Rules has been taken as a key requirement.

Table 5: Transmission options considered

Option	Key features	Details
1 (proposed)	330kV network reinforcement from Pinjar to Geraldton to be commissioned by November 2010.	Uses the corridor of the existing Pinjar-Regan-Cataby-Eneabba 132kV line, with a new line corridor from Eneabba to Geraldton. This option will provide a 330kV double circuit line with one side energised at 330kV and the second side initially energised at 132kV. One 330/132kV step-down transformer will be installed at Geraldton. Use of the existing Pinjar-Eneabba corridor requires re-supply at the Regan substation.
1A	Staged augmentation with construction of Eneabba-Geraldton as in Option 1 but with Pinjar-Eneabba commissioned by 2014	The Pinjar-Eneabba route will involve use of a new corridor adjacent to the 132kV line commissioned in 2004. Due to new corridor planning issues Western Power envisages this project cannot be commissioned until Nov 2014. Includes allowances for SVC.
1B	As Option 1 but with Pinjar-Eneabba delayed until 2011 and Eneabba-Geraldton by Nov 2010 initially energised at 132 kV	This option is designed to assess potential cost savings from delaying the Pinjar-Eneabba section of the proposed augmentation. Includes allowance for SVC.
1C	Deferral of Option 1 by one year to Nov 2011	Includes allowance for SVC
2	132kV reinforcement between Eneabba and Geraldton with 330kV line (as in Option 1) deferred until Nov 2014	This involves construction of a 175km single circuit 132kV line between Eneabba to Rangeway (Geraldton) by November 2010, with the 330kV reinforcement deferred until 2014. Additional allowance required for SVC
2a	As Option 2 but with double circuit 132kV line between Eneabba and Rangeway substation at Geraldton	Includes allowance for SVC.
3	Construction of additional 132kV line from Eneabba to Three Springs and Mungarra-Rangeway and deferral of Option 1 until 2014	This involves construction of a single circuit 132kV line (75km) between Eneabba and Three Springs and a 132kV single circuit line (55km) between Mungarra and Rangeway (Geraldton). Includes allowance for SVC.
4	This involves sole reliance on upgrading using 132kV lines	This involves construction of a double circuit 132kV line (175km) from Eneabba to Rangeway by Nov 2010, a double circuit 132kV line (300km) between Eneabba and Three Springs by 2015, a 132kV line from Eneabba to Geralton by 2021 and a further 132kV line from Eneabba to Geraldton by 2025. Includes allowance for SVC
5	220kV reinforcement option by Nov 2014	This involves construction of a double circuit transmission line from Northern Terminal to Cataby and Cataby to Geraldton; and installation of 220kV terminals at Northern Terminal, Cataby and Geraldton
6	330kV reinforcement with line towers designed for 500kV by Nov 2014	This is identical to Option 1 except that the 330kV double circuit lines will be constructed on towers designed for 500kV lines
7	Bipole HV/DC reinforcement by Nov 2014	This involves construction of a 500kV two-wire HV/DC line from Northern Terminal to Cataby and Cataby to Geraldton; and installation of 3 bipole HV/DC converter stations at Northern Terminal, Cataby and Geraldton.
8	Do nothing	

Source: Western Power

Western Power has assessed these options on the basis of technical compliance. This assessment has concluded that Options 2, 3 and 8 are not viable:

- Options 2 and 3 are not viable because they involve single circuit augmentation. As a result these do not satisfy the technical requirement to maintain service on the network during N-1 contingencies;
- Option 8 is not viable under any circumstances as it fails to address system security and reliability requirements under current loads and therefore will not address those requirements under any forecast that involves any increase in load.

4.1.2. Generation options

Western Power has considered the following generation options:

Table 6: Generation options considered

Option	Key features	Details
9	Additional gas turbine at Mungarra Power Station	Installation of Frame 6 turbine
10	Additional Frame 9 gas turbine near Geraldton	Use of a new Frame 9 gas turbine to be located at Mungarra PS or other location near Geraldton
11	Permanently island the NCR from the SWIS at Three Springs	While not strictly a generation option it will rely on local generation meeting demand in the NCR

Source: Western Power[19]

Western Power advises that none of these options are technically feasible:

- Options 9 and 10 are not feasible because of synchronous stability constraints and associated reduction in the transmission transfer limit. This means that transmission augmentation is necessary before additional generation can be connected
- Transmission constraints will still exist under an islanded system (Option 11). In particular it will be difficult to meet the stability requirements with substantial wind generation, which would be a key source of generation under this option. This is further complicated by the question of how the electricity market would operate with physical separation of systems, and the likely knock-on effects for affected generators.

Furthermore, the ability for a hybrid transmission/generation option to work is restricted by the need for adequate transmission reinforcement for synchronous stability reasons. Due to these limitations this report does not discuss the feasibility of generation options further.

19 Description of Option 10 corrected by Western Power in this Final Report v2 due to misinterpretation.

4.1.3. Demand side management options

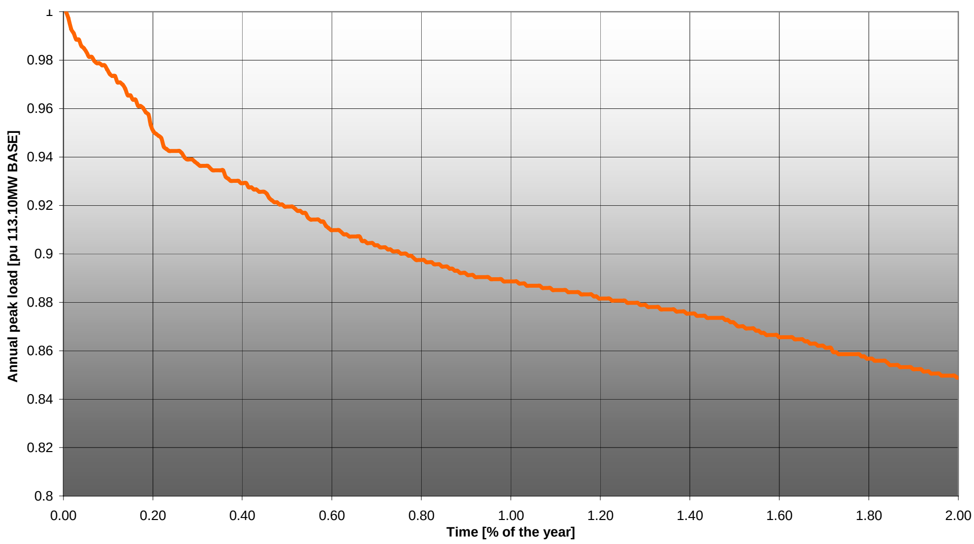
This option involves implementing a Demand Side Management (DSM) Program to encourage customers to reduce load voluntarily during peak demand days. It should be noted that DSM is not strictly a stand-alone option. Due to ongoing load growth, DSM on its own will not defer the need for reinforcement (or other potentially viable supply side options). At best DSM may incrementally reduce peak demand and potentially defer the need for reinforcement for a short period of time.

For DSM to be effective, load reductions will need to come from customers served by one of the six zone substations north of Eneabba and Muchea (Chapman, Durlacher, Geraldton 33 kV, Golden Grove, Three Springs, Moora).

Historical Load Characteristics for 2005/06 Summer

Over the period 1 November 2005 to 31 October 2006 demand on the NCR system north of Eneabba/Muchea ranged from a low of about 50 MW to a maximum of 113 MW on the peak summer day. A load duration analysis for this period, as shown in Figure 4, indicates that the top 12% of load, about 13 MW, occurred for just 80 hours or less than 1% of the year. The fact that the load is quite ‘peaky’ indicates that DSM could potentially provide a useful strategy for mitigating the extreme peak loads on those few occasions during the year when they occur.

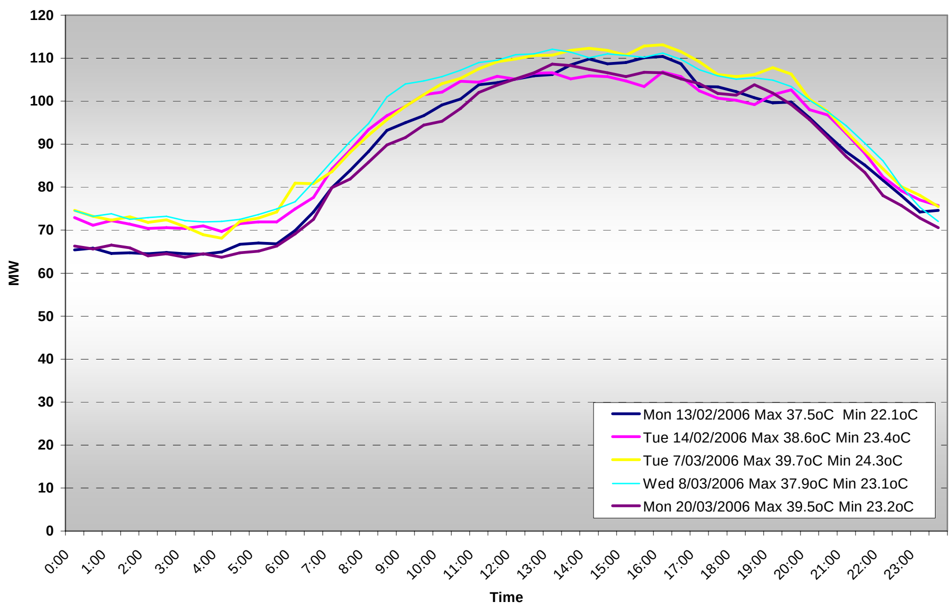
Figure 4: NCR 2% Load Duration Curve (1 Nov 2005 – 31 Oct 2006)



Peak Day Load Profiles

Figure 5 illustrates the daily load profiles for the five highest demand days during the 2005/06 summer, along with the date and maximum and minimum temperatures of each occurrence. During this summer period, the highest demand of 113 MW occurred at 4:30 PM on Tuesday 7 March. From the profiles it can be seen that the peak day loads show a relatively consistent pattern. The load tends to: 1) build steadily over the period 8:00 AM to 2:00 PM; 2) reach a peak at about 4:30 PM; 3) then decrease until about 6:30 – 8:00 PM when a secondary peak becomes apparent on four of the five peak days.

Figure 5: Load Profiles for Five Highest Demand Days in Summer 2005/06

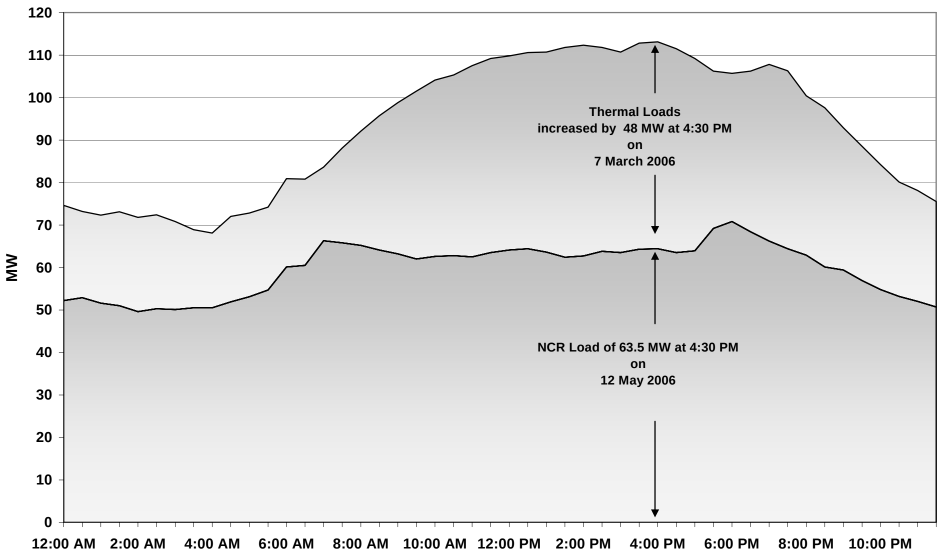


Note that these times relate to the period prior to the trialled introduction of daylight saving in Western Australia.

Temperature Sensitivity of Peak Day Loads

The absolute MW impact of peak summer temperatures on the NCR system loadings is illustrated in Figure 6. This analysis, which is based on comparison of the load profile recorded on the peak summer day in March 2006 with the profile for a neutral day (non-heating/non-cooling) day in May 2006, indicates that there is a fairly significant temperature dependant load of about 48 MW. The majority of this load is likely to be from commercial and residential air-conditioning and refrigeration.

Figure 6: Impact of Temperature on NCR ZS Load (excludes losses)



What can potentially be achieved?

A simple top down 'rule-of-thumb' analysis, based on experience elsewhere, can be used to estimate the load reduction potentially available in the NCR. This provides a useful benchmark prior to embarking on more detailed analysis of potential at the customer level.

A good example of recent and local experience in large scale DSM programs is Synergy's Peak Demand Saver program. The program offers financial incentives to medium to very large commercial and industrial customer to enter into contracts with Synergy to provide load reductions 'on call'. The program was first offered to customers in summer 2004/05 and was successful in contracting over 80 MW of load reduction capacity. In 2004/05 the system peak on the SWIS was about 3,000 MW. The contracted DSM capacity therefore represented 2.7% of system peak demand.

A survey recently conducted by the Federal Energy Regulatory Commission (FERC) of 200 US utility DSM programs targeting peak demand reduction reported DSM potential ranging between 3 – 7% of peak demand[20]. This range includes impacts achieved from a diverse number of DSM programs targeting every customer sector including residential, small-medium business and large commercial and industrials. The customer composition in the NCR, as shown in Table 2, is diverse and includes customers from all these sectors.

20 Federal Energy Regulatory Commission, *Assessment of Demand Response & Advanced Metering*, August 2006

If Western Power were to implement DSM initiatives targeting all sectors in the NCR then 5% of peak demand would seem a reasonable working estimate of what could be achieved. A more modest program targeting just large commercial, industrial and mining customers,[21] similar to the Peak Demand Saver, is likely to yield lower impacts.

4.2. SCENARIOS

Costs and benefits have been assessed under different demand and discount rate scenarios. Furthermore, the impact of different modelling periods has been considered.

4.2.1. Demand scenarios

The following demand scenarios have been developed by Western Power and are considered in this report:

- Low forecast – this involves a conservative estimate of growth from existing customers, including smaller loads that Western Power is either committed to connecting or has reached a connection agreement with;
- High forecast – this involves all the growth in the low forecast plus 100% connection of identified block loads; and
- Central forecast – this is an intermediate forecast that adds the probability-weighted new block loads to the low forecast.

4.2.2. Discount rate scenarios

Western Power has applied a discount rate of 6.6% pre-tax real in its cost assessment. This rate is based on the corporate cost of capital. As an alternative scenario we have considered a social discount rate of 2.5%. The derivation of this discount rate is set out in Appendix B:

21 These customer segments represent a relatively small number of customers that, in aggregate, are likely to account for a significant proportion of the total peak demand. A DSM program focusing on these customer types only is likely to yield the largest gains while minimising transaction costs.

4.2.3. Modelling period

For the purpose of analysis we have used a 24 year modelling period encompassing the period 2007-2030. There is a trade off in extending the modelling period: a longer period encompasses more of the life of the proposed asset, while the accuracy of any forecast is diminished the longer the modelling period. This trade off has been resolved in different ways in different jurisdictions. In the NEM a 10 year modelling period has typically been adopted in assessing transmission augmentation proposals but with a terminal value to account for the time after the end of detailed modelling. However, in Transpower's application for a 400KV augmentation in New Zealand it used a modelling period of well over 30 years (up to 2040), while the Electricity Commission assessed the application using a modelling period ending in 2030.

As an additional sensitivity we have also considered if the results would differ if a shorter time horizon were considered, such as the 15 years contemplated for the assessment of capital contributions in the Access Code.[22]

22 Clause A4.10 of the Access Code defines a "reasonable time" in the context of capital contributions as up to 15 years.

5. EVALUATION OF COSTS AND BENEFITS BY SCENARIO

5.1. LOW DEMAND (ORGANIC GROWTH)

5.1.1. Discount rate of 6.6%

The net present cost (NPC) of the various options estimated by Western Power under this scenario is set out in Table 7. This shows that the NPC of Option 1 is lower than all other options except for Option 1A:

Table 7: Low growth - NPC of Options 1-7 with discount rate of 6.6% ($m)

Option	NPC	Difference from Option 1
1	[ ]	NA
1A	[ ]	-8.8
1B	[ ]	15.8
1C	[ ]	7.5
2A	[ ]	38.1
4	[ ]	59.9
5	[ ]	157.5*
6	[ ]	47.5*
7	[ ]	147.5*

Source: Western Power. Financial information withdrawn due to sensitivity of future tendering process. * based on a minimum indicative cost.

Options 5, 6 and 7 are all significantly higher cost options than Option 1. None of these options provide any additional benefits to Option 1 that offset the higher cost.

Option 5 (220kV) also provides a lower increment to capacity than any of the 330kV options because it provides lesser improvement in system stability. Therefore, there is no expectation of benefits to offset the higher cost to the 330kV options.

Options 6 and 7 (500kV) have a number of common deficiencies:

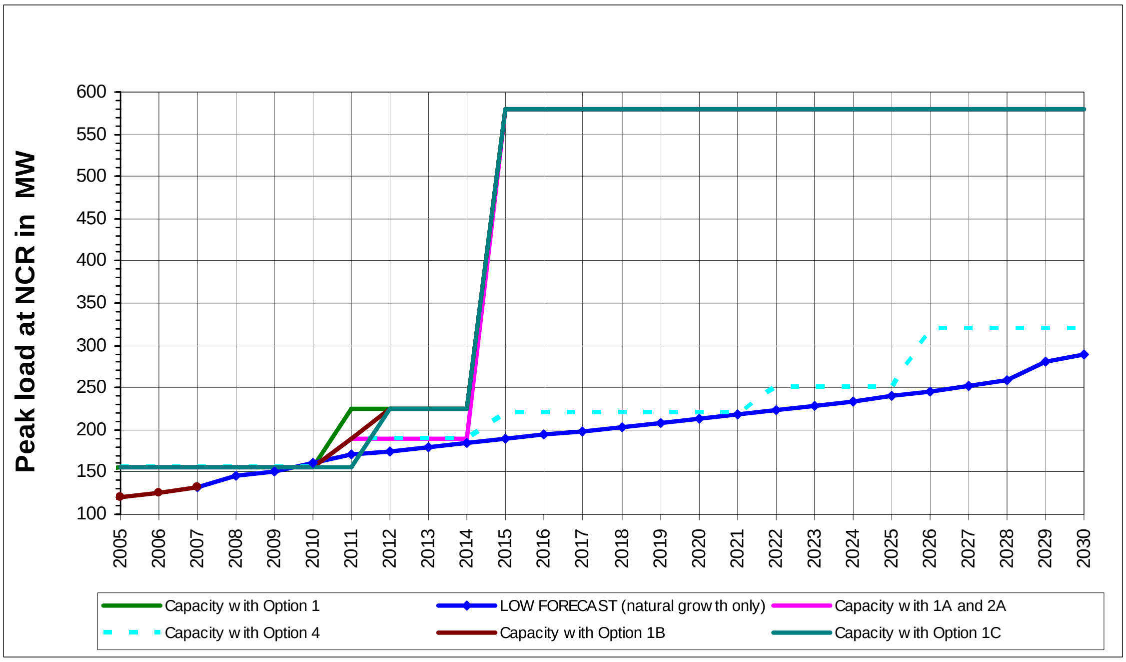
- Where a lower cost 330kV option meets all expected load over the timeframe modelled, then there are limited benefits that a 500kV option could provide. There are potentially positive aspects of a 500kV option such as lower losses and ability to meet substantially higher transfer requirement but these are likely to be either second order or largely redundant; and

- The potential for growth in generation means that there is a real possibility that the net transfer of energy in the future will be from the NCR to Perth, not vice versa. If there is significant generation located in the NCR, Western Power advises that 500kV augmentation may not be necessary for voltage stability purposes, with a more effective outcome being to augment the network initially to 330kV double circuit allowing for a further single circuit in the future.

The feasibility of 220kV options are not considered further in this paper. We only consider the potential role for 500kV options where 330kV augmentation may provide insufficient capacity.

All the other options costed (Options 1, 1A, 1B, 1C, 2A and 4) provide sufficient transmission capacity to meet anticipated load growth over a 24 year period. By definition these will also provide sufficient capacity over a 15 year period.[23]

Figure 7: Low demand scenario: Estimated peak capacity and demand up to 2030



Note that the transfer capability will also be a function of whether generation is located in the NCR or imported from the SWIS. Load in excess of the stated capacity may be possible with increased local generation.

23 Note that meeting this load growth is also contingent on sufficient generation in the Metro area or NCR to meet this forecast demand.

However, there will be transitory issues with some of these options. For example, Option 1C is expected to result in a capacity shortfall in 2010/11 of at least 16MW.[24]

A range of benefits is provided by Option 1 under this scenario. These include:[25]

- A rapid expansion in capacity soon after 2010;
- The ability to connect significant new generation;
- The facilitation of entry of lower cost generation from the SWIS into the NCR;
- The facilitation of entry of lower cost generation from the NCR into the SWIS;
- Reduction in transmission losses as a percentage (lower losses at higher voltages) in the NCR;
- Reduction in the need for ongoing reactive power support (that is, SVC); and
- Lower operation and maintenance costs, especially in relation to lower maintenance needs on the new line.

Where the cost of 330kV augmentation is less than the cost of 132kV augmentation 330kV augmentation options will have greater net benefits because 330kV augmentation necessarily dominates in terms of:

- Having lower need for reactive power support for provision of a given load;
- Allowing for greater connection of generators and loads (that may not be included in the forecast); and
- Having lower line losses and lower maintenance costs due to fewer towers.

Due to the high relative cost of the 132kV options (Options 2A and 4) the preferred option will be a 330kV augmentation. Of these alternatives, Option 1 is superior to both Options 1B and 1C. Capacity benefits occur earlier with Option 1 than Options 1B and 1C. Moreover, Option 1C is arguably non-compliant due to the inability to meet peak load in 2010-11. As Option 1 has a lower NPC than Options 1B and 1C it must have a higher net benefit.

24 This could be acceptable if there were sufficient potential to curtail loads. However, even if it is assumed that DSM can provide a 5% reduction in peak load, there will still be a capacity shortfall.

25 These benefits may also include environmental benefits that are not quantified in this report. Lower carbon dioxide emissions may result from the ability to connect more wind farms, the reduction in transmission losses and the use of more efficient generation.

The only issue is whether the net benefits associated with Option 1 are greater than those associated with Option 1A - a lower cost option. This can only occur when the benefits associated with Option 1 are sufficiently larger than those associated with Option 1A to outweigh the cost differential.

The main difference between these two options is that under Option 1A, capacity augmentation is provided later than under Option 1. While Option 1A provides sufficient capacity over the period up to 2014 to meet expected natural growth demand there are a number of areas where Option 1 is preferable to Option 1A. Option 1A will have lower benefits in the following areas:

- Unserved energy – as it has lower spare capacity, which provides less flexibility against outages and in relation to volatility in load around the forecast;
- Operating costs – the lower transmission capacity (in particular the lack of a 330kV line until 2014) limits the new generation that can be connected onto the NCR network prior to 2014, thereby deferring the ability for low cost generation to displace more expensive plant in the NCR (and potentially also in the SWIS); and
- The capacity to connect any new block loads (though these are assumed away under this scenario).

Under Option 1A the spare capacity for the NCR goes down to 6 MW by 2014. This implies a very high risk of outage because a single outage of the smallest generator would entail unserved energy. Option 1 in comparison has significantly higher spare capacity. The avoided expected unserved costs alone may offset the higher cost of option 1. Our preliminary analysis suggests if Option 1 could cover for 6 hours/year of unserved energy, the resultant benefits could compensate for its higher cost. In other words, it is likely that Option 1 would have a higher net benefit compared to option 1A considering only one of the three components of benefit. In addition to avoided unserved energy, option 1 may also have lower fuel and generation capital costs that we have not considered.

There is also a significant risk that if the transmission upgrade does not occur by 2010/11, some of the generation opportunities may not be realised. Table 4 set out a range of new generation options, many of which are committed for construction prior to 2014. If a number of these generators cannot connect to the transmission network until 2014 there is a high possibility that the generators will either not proceed (a particular issue with windfarms) or locate elsewhere.

In summary, in considering option 1A, one has to consider the potential for some of the capacity and fuel cost benefits arising from new generation to be significantly reduced that will make a further and potentially very strong case for Option 1 ahead of Option 1A.

Potential role for DSM

In section 4.1.3 we noted that a rough rule of thumb suggested that DSM could potentially reduce peak demand by up to 5% per annum. The anticipated capacity shortfall in 2009-10 is within this limit as set out in Table 8.

Table 8: Low demand forecast; potential role for DSM

Summer	2006/07	2007/08	2008/09	2009/10	2010/11
System capacity	155	155	155	155	155
Load Exceeding Capacity (MW)	-	-	-	6	16
% Exceedance relative to Capacity	0%	0%	0%	4%	10%
Estimated Hours at Risk				14	58
MWh at Risk				84	928

The loads exceeding the rated capacity of the network set the target amount of load reduction that DSM resources would need to deliver to provide a viable alternative to the supply side reinforcement option. Since the network reinforcement is required by summer 2010/11, DSM resources would need to deliver somewhere in the order of 16 MW of load reduction to defer the need for the reinforcement for a year. This load reduction is roughly twice the percentage load reduction delivered by well-developed DSM programs. However, it seems plausible that a DSM program may mitigate the capacity shortfall in 2009-10.

As the benchmark percentage load reductions achievable through DSM are insufficient to defer capacity augmentation by even one year in a low demand scenario, they will also be insufficient in a higher demand scenario. Furthermore, as generation is an infeasible option without transmission augmentation the potential for a combined DSM/generation option is limited. Therefore, we do not consider DSM further in the various scenarios modelled.

Summary

For the low demand scenario, Option 1A has the lowest NPC. However, Option 1A provides capacity later than Option 1. This implies a trade off between the two options as Option 1 is likely to have a higher benefit in relation to unserved energy and operating cost savings, including those related to the ability to connect new generation. The additional benefits associated with Option 1 – especially in relation to connecting new generation – are likely to be sufficiently significant as to outweigh any cost saving that in any case is likely to be small. Therefore, it is difficult to reject the hypothesis that Option 1 is the preferred option under this scenario.

5.1.2. Discount rate of 2.5%

The net present cost (NPC) of each 132kV or 330kV option under this low growth, low discount rate scenario is set out in Table 9. The main change under this discount rate is that the NPC of Option 1 is lower than the NPC of Option 1A.

Table 9: Low growth - NPC of Options 1-4 with discount rate of 2.5% ($m)

Option	NPC	Difference from Option 1
1	[ ]	NA

1A	[ ]	5.6
1B	[ ]	25.3
1C	[ ]	20.1
2A	[ ]	78.8
4	[ ]	111.7

Source: Western Power. Financial information withdrawn due to sensitivity of future tendering process.

Under this scenario Option 1 has the lowest NPC and provides additional capacity at the earliest date. Therefore, there is no case to reject the hypothesis that Option 1 is preferable.

5.2. HIGH DEMAND

5.2.1. Discount rate of 6.6%

The Net Present Cost of each of the 132kV and 330kV options is set out in Table 10. Under the high demand scenario the costs associated with Options 1, 1B and 1C are slightly higher than in the low demand scenario as the costs assume that the 330kV line will be run on both circuits at 330kV immediately upon construction. As the Pinjar-Eneabba section of the 330kV under Option 1A will not be constructed until 2014 we have assumed there are no benefits from operating the Eneabba- Moonyoonooka section of the line at double circuit 330kV until 2014. Therefore, the NPC of Option 1A is unchanged.

Table 10: High growth - NPC of Options 1-4 with discount rate of 6.6% ($m)

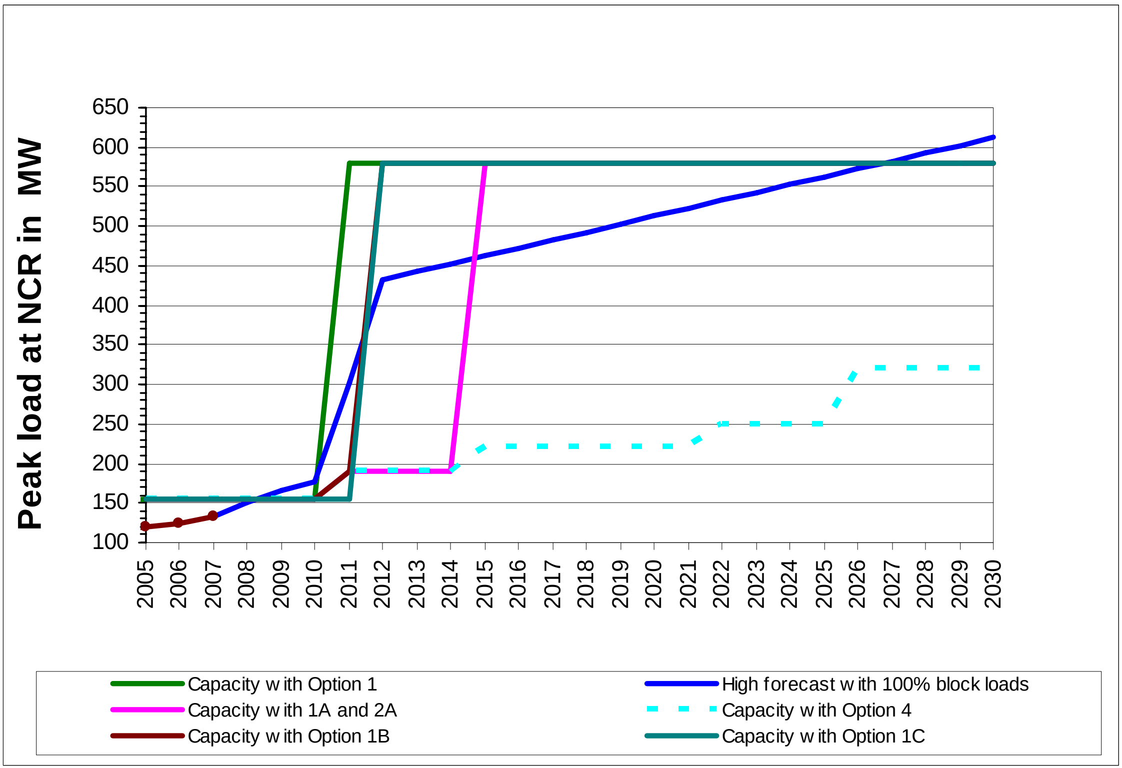
Option	NPC	Difference from Option 1	Max capacity MW (date achieved)
1	[ ]	NA	580 (2011)
1A	[ ]	-13.1	580 (2015)
1B	[ ]	15.6	580 (2012)
1C	[ ]	7.2	580 (2012)
2A	[ ]	32.8	580 (2015)
4	[ ]	55.6	220 (2015)

Source: Western Power. Financial information withdrawn due to sensitivity of future tendering process.

Demand in excess of 600MW is forecast by 2030 under the high demand scenario as set out in

Figure 8.

Figure 8: High Demand Scenario: Estimated peak demand and capacity up to 2030



Option 4 falls well sort of meeting forecast demand under this scenario. Note that Option 4 also does not meet demand if a shorter 15 year modelling period is considered. Options 1, 1A, 1B, 1C and 2A will all provide sufficient capacity by 2015 for the period up to 2026, but are all expected to fall short at meeting forecast demand by the end of the period.

In assessing the suitability of the various options we focus on two distinct periods: 2011-15 and 2026-30.

There are differences in the ability of each of the options to meet demand in the period 2011-15. In particular, Option 1 is the only option that provides capacity greater than expected demand in 2011, while Options 1, 1B, and 1C are the only options that provide sufficient capacity in the period 2012-14.

These timing issues are illustrated in Table 11.

Table 11: High demand – Demand and capacity by option 2010-15 (MW)

Option/Demand	2010	2011	2012	2013	2014	2015
High Growth	177	303	433	443	453	463
High Growth excluding Gindalbie	171	193	323	333	343	353
1	155	580	580	580	580	580
1A	155	190	190	190	190	580
1B	155	190	580	580	580	580
1C	155	155	580	580	580	580
2A	155	190	190	190	190	580
4	155	190	190	190	190	220

Shaded areas indicate where there is insufficient capacity.

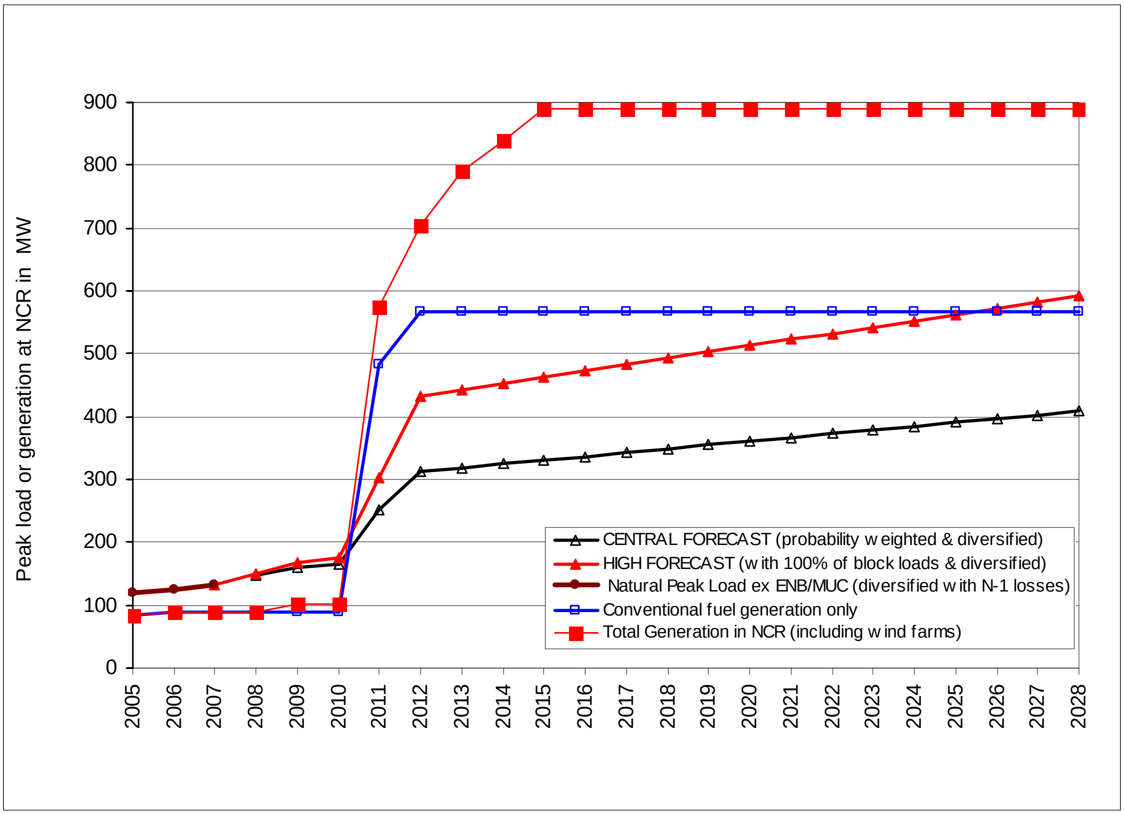
Even if early delivery of capacity has an extremely low value, Option 1 is superior to all other options over this period. As Option 1A does not provide sufficient capacity until 2015 it is less compliant than the other options apart from 2A and 4 during this period.

As all the listed Options in Table 11 are unable to meet forecast demand in the few years prior to 2030, Western Power has developed two modifications to the Options to be implemented if demand increases as per this scenario. These are the following:

- Modification to Option 1 to construct a new 410km 330kV single circuit line from Northern Terminal to Moonyoonooka by 2028; and
- A revised Option 6 that involves construction of 500kV towers that are initially operated at 330kV but are converted to 500kV in 2028.

The NPC of the modified Option 1 is [ ]m,[26] while the NPC of the revised Option 6 is [ ]m. Both options meet forecast demand up to 2030. The significantly lower cost of modified Option 1 suggests that if there is need for subsequent augmentation, initially upgrading the line to 330kV is the lowest cost option. However, in practice the necessity to augment the network for a given (high) demand will also depend on the level of local generation. As set out in Figure 9, even under the high demand scenario there is a prospect of sufficient local generation to meet all NCR demand. If this is the case and the net transfer of power is in a North-South direction, the transfer capability of the transmission network will be enhanced beyond the 580MW assumed for double circuit 330kV augmentation. This highlights the flexibility within Option 1 to accommodate significantly increased demand and or local generation.

Figure 9: NCR Load forecast versus Generation - Peak forecast north of Eneabba/Muchea with N-1 losses



Note that the total generation (including windfarm) line represents the hypothetical "best case" scenario involving all windfarms running at 100% utilisation at the time of system peak demand.

As Option 1 has lower NPC than the other alternatives, the hypothesis that Option 1 has the highest net benefit is not rejected under this scenario.

26 Note that the modification could theoretically be applied to all the 330kV options, which would increase the cost of each option by the same amount. However, as Option 1 is the lowest cost option that meets demand in the period 2011-15 we have not applied this modification to the other options.

5.2.2. Discount rate of 2.5%

With a discount rate of 2.5% Option 1 has a lower NPC than all other 132kV and 330kV options.

Table 12: High demand scenario - NPC of Options 1-4 with discount rate of 2.5% ($m)

Option	NPC	Difference from Option 1
1	[ ]	NA
1A	[ ]	3.5
1B	[ ]	25.2
1C	[ ]	20.0
2A	[ ]	76.7
4	[ ]	177.1

Financial information withdrawn due to sensitivity of future tendering process

As Option 1 necessarily provides higher benefits than other options the hypothesis of a dominant option (Option 1) is not rejected under this scenario.

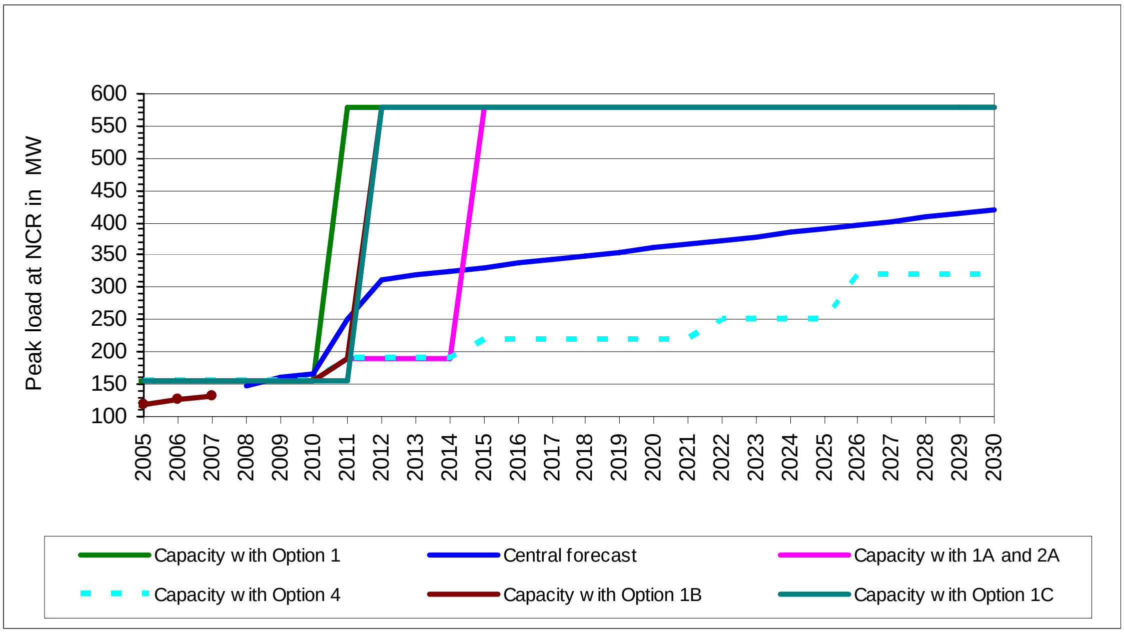
5.3. Central Demand

5.3.1. Discount rate of 6.6%

The central demand scenario involves adding the probability-weighted new load to the base forecast. The NPC of the options under this scenario are identical to those in the High demand scenario (with discount rate of 6.6%) as it is assumed that meeting the levels of demand under this scenario necessarily requires the provision of double-circuit 330kV lines at the earliest opportunity.

Under this scenario the 330kV options provide sufficient capacity for the period from 2015 to 2030 as set out in Figure 10. Option 4 (132kV augmentation) is ruled out as providing insufficient capacity.

Figure 10: Central demand scenario: Estimated peak demand and capacity to 2030



Therefore, the key criterion in ranking the net benefits of the various 330kV augmentation options is capacity availability during the period 2010-2015. This is summarised in Table 13.

Table 13: Central demand – Demand and capacity by option 2010-15 (MW)

Option/Demand	2010	2011	2012	2013	2014	2015
Central Growth	166	251	313	319	325	331
Central Growth excluding Gindalbie	162	174	236	242	248	254
1	155	580	580	580	580	580
1A	155	190	190	190	190	580
1B	155	190	580	580	580	580
1C	155	155	580	580	580	580
2A	155	190	190	190	190	580
4	155	190	190	190	190	220

Shaded areas indicate where there is insufficient capacity. Note that Demand excluding Gindalbie is also shown for completeness, but using this demand set does not alter the conclusions.

If we assume the lower level of demand (that is, excluding Gindalbie) is applicable, the benefits associated with Option 1 and Option 1B are equivalent. The benefits with Option 1C are lower and the other options are largely non-compliant in that they result in capacity shortfalls in at least 3 of the years 2011-2014. As Option 1 has the lowest NPC of compliant options we conclude that there is no reason to reject the hypothesis that it is the preferred option.

5.3.2. Discount rate of 2.5%

The NPC of the options will be as in Table 12. As the benefits will be ranked identically as in Table 13 the same conclusion will arise – that there is no reason to reject the hypothesis that Option 1 is preferred.

5.4. Summary of Scenario Analysis

As set out in Table 14, Option 1 is preferred under all scenarios tested.

Table 14: Summary of preferred option by scenario

Scenario	Discount rate 6.6%	Discount rate 2.5%
Low demand	Option 1	Option 1
High demand	Option 1	Option 1
Central demand	Option 1	Option 1

The scenarios developed encompass plausible estimates of demand. Given the dominance of 330kV in terms of benefits and the lower costs involved, it is unsurprising that Option 1 is the dominant option as it provides benefits sooner and at a low (relative) cost. Option 1 is especially dominant in circumstances that are most plausible: that is, ones encompassing high demand growth, including from block loads and connection of new generation.

The dominance of Option 1 also provides strong prima face evidence that there is no need to specifically quantify the net benefits.

6. CONCLUSION

The rank-ordering of net benefits supports the hypothesis that the proposed transmission augmentation Option 1 is superior to the other transmission options considered, including doing nothing. Sensitivity testing to different demand and discount rate scenarios demonstrates the robustness of this result. The results are also robust to a shorter modelling period. Demand side management options were considered, but were found to be insufficient to defer capacity investment even by one year. The three generation options considered failed to satisfy the threshold feasibility test—in part because new transmission capacity would be needed anyway to support new generation.

This case is somewhat unusual because of the scale of and uncertainty over possible industrial developments in the NCR. The fact that Option 1 is flexible, in that it provides scope to connect significant new load, but is still preferable under low demand growth, is an added and important factor in it being the superior option.

APPENDIX A: DOCUMENTS REVIEWED

1. Government Gazette of Western Australia, Electricity Network Access Code, 30 November, 2004.

2. Western Power Corporation, North Country Region Load Forecast, Excel Spreadsheet NCR Forecast November 2006.xls, November, 2006.

3. Western Power Corporation, NPC Analysis for Reinforcement of Options 1-4, Excel Spreadsheet Financial Analysis NPC Op1-4.xls, November, 2006.

4. Western Power Corporation, 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-3339124v4, December 2006.

5. Western Power Corporation, Generation Requirement For North Country System In 2006, Study Note SN 834, System Simulation Section, July 2005.

6. Western Power Corporation, Study Notes of North Country Region – Long Term Development Plan, NBU 03-2003, April 2003.

APPENDIX B: ESTIMATING A SOCIAL DISCOUNT RATE

In the literature, the social discount rate is referred to as the "social rate of time preference" (SRTP). The SRTP is not an observable rate, but may be inferred from observations of other rates.

The SRTP is the marginal rate of time preference for society as a whole rather than the rate for individuals. The SRTP may differ from the individual's marginal rate of time preference, and arguments have been advanced both as to why it could be higher or lower.[27] A reasonable approximation that is often used in practice is to assume that the SRTP is equal to the individual's marginal rate of time preference.

The first means of estimating the marginal rate of time preference is to note that consumers face an opportunity cost of forgone interest when we consume now rather than save for the future. In equilibrium in perfect markets, consumers will trade consumption now for consumption in the future until the marginal rate of time preference is equal to the real after-tax rate of interest that can be earned on saving.[28] Thus, one estimate of the SRTP is the after-tax interest rate on (risk-free) investments. This analysis is complicated by the fact that different individuals face different marginal tax rates. As a first approximation, we assume that the average marginal tax rate across all consumers is 30%. The yield on long-dated Treasury Fixed Coupon bonds was 5.47% on 5 December 2006,[29] so the estimated nominal SRTP is 3.8%.[30] Inflation for the three years ending September 2006 has averaged 2.8%.[31] Assuming that inflation in the recent past conditions expectations of future inflation, then the expected real after-tax rate interest rate (and hence the real SRTP) is 1.0%.

The second means of estimating the marginal rate of time preference is a more fundamental calculation of what is known as the consumption rate of interest (CRI).

The CRI is estimated as:

$$s = \delta + \mu \cdot g$$

where δ is the "rate of time preference" (the rate at which utility is discounted), μ is the elasticity of the marginal utility of consumption, and *g* is the expected rate of growth in average consumption per capita.

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27 See Boardman, Anthony E., David H. Greenberg, Aidan R. Vining, and David L. Weimer (2001) *Cost-Benefit Analysis: Concepts and Practice*, Prentice Hall: New Jersey, p.166.

28 Ibid, p.166.

29 Source: Reserve Bank of Australia.

30 This is based on adjusting the pre-tax return on Fixed Coupon bonds (5.47%) by the tax rate. The post-tax interest rate is then 5.47% x (1-0.30) = 3.83%

31 Calculated as the arithmetic average of quarterly Year-on-Year CPI estimates, Reserve Bank of Australia.

The rate of time preference can be further defined as:[32]

$$\delta = \rho - L$$

where ρ is the "pure rate of time preference", which is the rate at which welfare arising in the future is discounted purely by virtue of this utility arising later; and *L* is the "rate of growth of life chances".[33]

There is no clear agreement around the value of ρ, with some commentators suggesting that it should be equal to zero on point of (philosophical) principal that present consumption should not be assumed to be more valuable than future consumption. Setting that argument aside, HM Treasury (2003:98) use an estimate of $\delta = 1.5$ without considering how this is comprised of ρ and *L*.[34] If Pearce and Ulph's (1995:8) estimate of $L = -1.1$ is correct, then this implies $\rho = 0.4$. Pearce and Ulph (1995:16) use a range of 0 to 0.5, with a best estimate of $\rho = 0.3$.

Pearce and Ulph estimate *L* as the death rate. The Australian Bureau of Statistics calculates the standardised death rate as 6.0 deaths per 1,000 people,[35] which equates to L = -0.60.[36] Given a range of $\rho = 0.3$ to 0.5, the Australia-specific value of *L* implies that $\delta = 0.90$ to 1.10. This accords well with Arrow's (1995) tentative view that the value of this parameter "should be about 1%".[37]

Based on an academic review of relevant studies HM Treasury adopts a value of $\mu = -1$.[38] Arrow (1995:17) uses a figure of $\mu = -1.5$. We consider both values to provide a range for the CRI.

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32 Note that this decomposition is not always performed, with the assumption being made that $\delta = \rho$.

33 See Pearce, David and David Ulph (1995) "A Social Discount Rate for the United Kingdom", CSERGE Working Paper GEC 95-01, Centre for Social and Economic Research on the Global Environment, University College London and University of East Anglia, p. 6.

34 HM Treasury (2003) *The Green Book: Appraisal and Evaluation in Central Government*, Treasury Guidance: London. Note that HM Treasury and Pearce and Ulph have reversed the use of ρ and δ. We have followed the notation of Pearce and Ulph.

35 Australian Bureau of Statistics, *Deaths, Australia 2005*, 30 November 2006.

36 Pearce and Ulph divide total deaths by the total population and then multiply by 100. This is the same as the standardised death rate (0.0060) multiplied by 100.

37 Arrow, Kenneth J. (1995) "Intergenerational Equity and the Rate of Discount in Long-Term Social Investment", IEA World Congress, December, p. 17.

38 See Clarkson and Deyes, 2002: 53-54 and HM Treasury, 2003: 98.

Pearce and Ulph (1995:15) note that:

> *"[if] the population choose to substitute leisure for consumption, then a value of g based on real per capita consumption will understate the relevant magnitude. Second, real consumption per capita may fail to reflect rising social costs of consumption, in which case g will be overstated. One way to smooth out such considerations is to take [very] long-run rates of growth in real [per] capita consumption."*

The historical growth in average consumption per capita depends on the time period over which growth is measured. We have therefore taken the average of the cumulative average growth rate in per-capita consumption expenditure, calculated over three overlapping 15 year periods. As shown in Table 15 below, this provides an average of 2.29% for the cumulative average growth rate. We therefore use a value of g = 2.3%.

Table 15: Growth Rate in Per-Capita Consumption, Australia

Year	Household Final Consumption Expenditure (*)	Population	Consumption
	$million	persons	per Capita
1989	78,007	16,814,416	4,639
1990	80,015	17,065,128	4,689
1991	80,194	17,284,036	4,640
1992	81,986	17,494,664	4,686
1993	82,831	17,667,093	4,688
1994	86,523	17,667,093	4,897
1995	90,345	18,071,758	4,999
1996	92,714	18,310,714	5,063
1997	96,547	18,517,564	5,214
1998	100,920	18,711,271	5,394
1999	105,928	18,925,855	5,597
2000	110,107	19,153,380	5,749
2001	112,866	19,413,240	5,814
2002	117,652	19,640,979	5,990
2003	121,910	19,872,646	6,135
2004	128,737	20,091,504	6,408
2005	132,268	20,328,609	6,506
2006	136,096	20,328,609	6,695

15 Year Cumulative Average Growth Rates	
1989-2004	2.18%
1990-2005	2.21%
1991-2006	2.47%
Average	**2.29%**

Source: Australian Bureau of Statistics. (*) Household Final Consumption Expenditure is from the September quarter, trend series, chain volume, series A2303447K

Given the parameters above, the estimated CRI is in the range 3.20% to 4.55%. The mid-point of these values is roughly 3.9%.

As a sensitivity test we have used a value for the SRTP of 2.5%, which is an average of the two best point estimates (the SRTP of 1% and the CRI of 3.9%).

APPENDIX C: COMPLIANCE WITH THE NEW FACILITIES INVESTMENT TEST (NFIT)

This appendix considers whether the preferred option under the Regulatory Test assessment (Option 1) complies with the New Facilities Investment Test (NFIT).

C.1 THE NEW FACILITIES INVESTMENT TEST

The New Facilities Investment Test is set out in Sections 6.52 to 6.55 of the Access Code. The key section is 6.52:

6.52 New facilities investment may be added to the capital base if:

(a) the new facilities investment does not exceed the amount that would be invested by a service provider efficiently minimising costs, having regard, without limitation, to:

(i) whether the new facility exhibits economies of scale or scope and the increments in which capacity can be added; and

(ii) whether the lowest sustainable cost of providing the covered services forecast to be sold over a reasonable period may require the installation of a new facility with capacity sufficient to meet the forecast sales;

and

(b) one or more of the following conditions is satisfied:

(i) either:

A. the anticipated incremental revenue for the new facility is expected to at least recover the new facilities investment; or

B. if a modified test has been approved under section 6.53 and the new facilities investment is below the test application threshold - the modified test is satisfied;

or

(ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or

(iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services.

C.2 INTERPRETATION OF SECTION 6.52(A)

We have been asked to assume that Section 6.52(a) is a cost-minimisation test, subject to two broad conditions. First, that the effects of economies of scale and scope are captured; and second, that the facility is able to provide for forecast sales.

Consideration of economies of scale and scope necessitates consideration of a sufficiently long time horizon to capture the cost differential from building capacity incrementally (thereby not reaping economies of scale) and building sufficient capacity to meet demand over a long period at the start of construction. This supports consideration of a period in the order of 25 years.

The need to provide sufficient capacity to meet forecast sales supports the development of a “best estimate” demand forecast. This differs from the approach taken under the Regulatory Test where a range of scenarios was adopted, including extreme (high and low) scenarios.

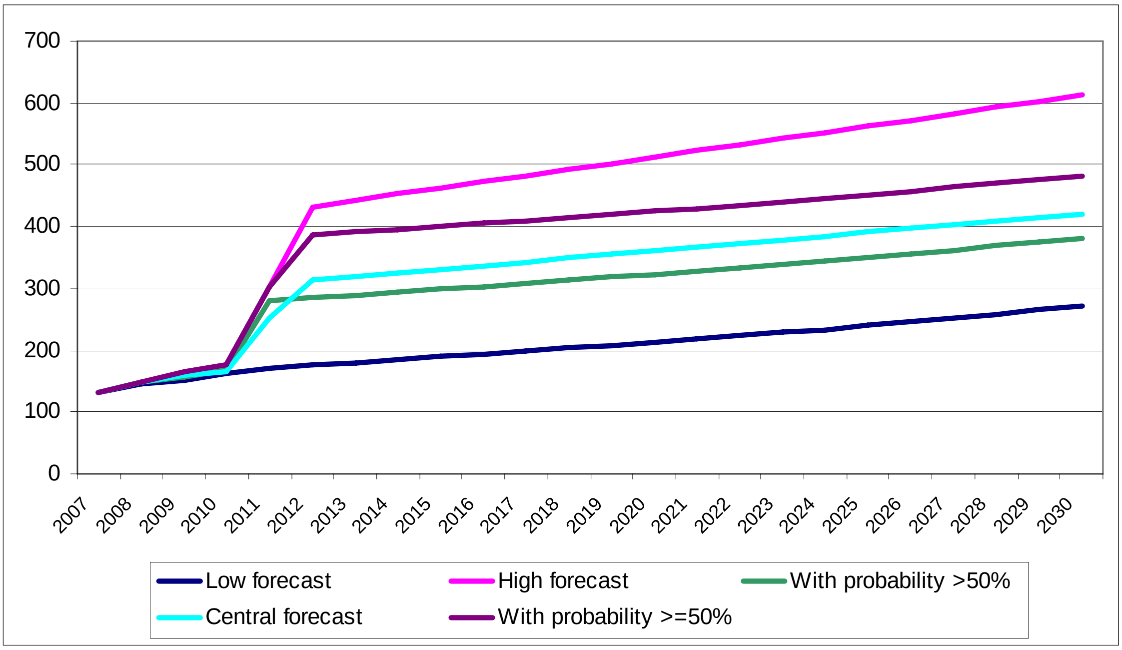
However, due to uncertainty over the likelihood of various block loads being added on to the network we have considered a number of approaches to a “best estimate” demand forecast. These include:

- Adopting the central forecast applied under the Regulatory Test, which consists of the low demand forecast (based on organic growth from existing customers) plus a probability weighted estimate of new block loads;
- Adding all block loads that Western Power has assumed a probability of connection of greater than 50% to the low demand forecast; and
- Adding all block loads that Western Power has assumed a probability of connection of at least 50% to the low demand forecast.

The two additional demand forecasts lie either side of the central demand forecast estimated as part of the Regulatory Test assessment. A comparison of the demand forecasts is set out in

Figure 11.

Figure 11: Comparison of NFIT demand forecast with Regulatory Test scenarios



As transmission charges are also paid by generators, Western Power has developed probability-weighted estimates of new connections. In keeping with the approach to demand for transmission capacity, we have developed three scenarios for generation augmentation:

- A probability weighted estimate of new block generation;
- A schedule of new generation based on the connection of only those generators assigned a probability of connection greater than 50%; and
- A schedule of new generation based on the connection of only those generators assigned a probability of connection at least equal to 50%.

For the purpose of the NFIT assessment we consider that the most appropriate discount rate is Western Power's regulatory cost of capital (pre-tax real of 6.6%). The Net Present Cost of each of the options under this discount rate are identical to those used on the Regulatory Test assessment under the Central and High demand scenarios, and are repeated in Table 16.

Table 16: NPC of augmentation options, best estimate demand forecast and discount rate of 6.6% ($m)

Option	NPC	Difference from Option 1	Max capacity MW (date achieved)
1	[ ]	NA	580 (2011)
1A	[ ]	-13.1	580 (2015)
1B	[ ]	15.6	580 (2012)
1C	[ ]	7.2	580 (2012)
2A	[ ]	32.8	580 (2015)
4	[ ]	55.6	220 (2015)

Source: Western Power. Financial information withdrawn due to sensitivity of future tendering process.

Options 1, 1A, 1B, 1C and 2A will meet forecast demand in the period 2015-2030. However, only Option 1 will meet demand in the period 2011-2014 as is set out in Table 17.

Table 17: Best estimate of demand – Demand and capacity by option 2010-15 (MW)

Option/Demand	2010	2011	2012	2013	2014	2015
Range bounded by various forecasts	167-176	280-302	285-386	289-391	294-395	299-400
1	155	580	580	580	580	580
1A	155	190	190	190	190	580
1B	155	190	580	580	580	580
1C	155	155	580	580	580	580
2A	155	190	190	190	190	580
4	155	190	190	190	190	220

Shaded areas indicate where there is insufficient capacity.

Therefore, Option 1 is the only Option that can "provide for forecast sales". Moreover, as Option 1 provides sufficient capacity in advance to meet forecast sales over the 24 year period considered it can also be inferred that Option 1 reflects economies of scale and the increments in capacity that can be added.

C.3 INTERPRETATION OF SECTION 6.52(B)

Section 6.52(b) requires that an augmentation option that passes 6.52(a) must also pass one of three tests: the incremental revenue test (i); the net benefit justifying a higher reference tariff test (ii); or the reliability test (iii).

In this assessment we consider each test in turn, but only attempt to evaluate compliance against legs (i) and (iii) due to data limitations.

C.3.1 Test (i) – incremental revenue test

The key plank of this test is sub-section (i)A which requires that the incremental revenue for the new facility is expected at least to recover the new facilities investment.

The “anticipated incremental revenue” is defined in section 1.3 of the Access Code as follows:

> ***anticipated incremental revenue*** *for a new facility means:*
>
> *(a) the present value (calculated at the rate of return over a reasonable period) of the increased tariff income reasonably anticipated to arise from the increased sale of covered services on the network to one or more users (where “increased sale of covered services” means sale of covered services which would not have occurred had the new facility not been commissioned),*
>
> *minus*
>
> *(b) the present value (calculated at the rate of return over the same period) of the best reasonable forecast of the increase in non-capital costs directly attributable to the increased sale of the covered services (being the covered services referred to in the expression “increased sale of*
>
> *covered services” in paragraph (a) of this definition),*

This plank of the test is designed to consider augmentation that is largely required to serve new load – and hence should result in incremental revenue.

In order to implement this plank of the test, one must estimate incremental revenue without invoking the circularity that if incremental revenue is estimated by consideration of the price the firm would charge to recover all capital costs associated with the preferred option then, *by definition*, anticipated incremental revenue should be sufficient to recover the new investment.

The approach we use to overcome this circularity is to assess the revenue that would be obtained from new customers and from expanding the demand of existing customers based on the best estimate of future prices under the preferred demand forecast(s). In undertaking this assessment we have considered the following material:

- The load attributable to existing and new customers under the “best estimate” demand forecast over the period 2007-2030;
- Western Power’s prices for the 2006-07 financial year, which (in the absence of an agreed Access Arrangement) are taken as the best estimate of future prices; and

- The capital costs set out in Table 16 above.

We have assumed that operating and maintenance costs associated with meeting the increased demand are relatively low and have not attempted to quantify these in this assessment.

We accept that a task of this nature requires a range of simplifying assumptions, especially in relation to the prices paid by new customers. For example, the transmission charges to customers with major block loads (and/or their structure) will be subject to negotiation, and are therefore not known with any degree of certainty in advance. Furthermore, the transmission charges paid by particular customers may vary depending on the nature of any connection agreement and variations in the demand profile over time.

Using a discount rate of 6.6% Table 18 sets out our estimate of the net present value of the revenue that will be obtained from new customers (block loads) new generators and the load growth of existing customers.

Table 18: Net Present Value of revenue under different demand scenarios using discount rate of 6.6% ($m)

Demand scenario	Revenue from new block loads	Revenue from new generators	Revenue from load growth	Total
Low demand plus all generators and block loads with probability >=50%	[ ]	[ ]	[ ]	[ ]
Central demand plus probability weighted generation load	[ ]	[ ]	[ ]	[ ]
Low demand plus all generators and block loads with probability >50%	[ ]	[ ]	[ ]	[ ]

Financial information withdrawn due to sensitivity of future tendering process

In all cases the Net Present Value of future revenue – only considering the period up to 2030 – is greater than the NPC of Option 1 over the same period ([ ]m). Note that if a longer modelling period were adopted the net present value of revenue would increase further, yet there would be no need for additional augmentation[39] necessitating an increase in cost.

While this analysis is high level in nature it suggests that Option 1 should meet this limb of the NFIT.

39 Note that in the high demand scenario considered as part of the Regulatory Test compliance, further augmentation is required before 2030. However, there is still significant available capacity in the transmission network under the central demand scenario in 2030.

C.3.2 Test (ii) – Net benefit justifying higher reference tariff

A “net benefit” is defined as “a net benefit (measured in present value terms to the extent that it is possible to do so) to those who generate, transport and consumer electricity in (as the case may be):

(a) the covered network; or

b) the covered network and any interconnected system.

A precondition for a “net benefit” to justify a higher reference tariff is that the net benefit is positive. The rank ordering process undertaken as part of the Regulatory Test ranked options without quantifying their net benefits. The expectation of a positive net benefit arises because Option 1 is so dominant compared with the “do nothing” option (Option 8). However, demonstrating a positive net benefit necessitates the difficult task of quantifying absolute benefits.

Therefore, if compliance of Option 1 against this limb of the NFIT test is to be considered, a greater degree of quantitative modelling than has been undertaken under the Regulatory Test assessment would be required. Additional data requirements for such an exercise would be significant. As it is only necessary to show compliance against one of the three limbs of the NFIT we do not consider this test further.

C.3.3 Test (iii) – reliability

This limb of the test requires consideration of whether the proposed augmentation (Option 1) is necessary for safety and reliability purposes to provide contracted covered services.

We have considered this limb of the test under two possible definitions. The first defines contracted covered services as only those that Western Power is currently committed to meet, namely the organic growth of existing customers and agreed new connections. This is equivalent to the low demand scenario developed under the Regulatory Test. The second defines contracted covered services as those Western Power expects to have to meet over the 20 year modelling timeframe.

Test (iii) under low demand scenario

In section 5.1 of the Regulatory Test assessment we concluded that Option 1 and Option 1A both met forecast demand under this demand scenario, with Option 1A meeting demand at a lower NPC.

However, while Option 1A meets the requirement of section 6.52(b)(iii) at lowest cost, it is non-compliant in respect of section 6.52(a)(ii) in that it does not allow Western Power to meet forecast sales. Furthermore, Option 8 – “do nothing” – was ruled out as failing to allow Western Power to meet forecast demand and provide a secure network

Therefore, as the lowest cost option that allows Western Power to meet safety and reliability requirements, Option 1 complies with this limb of the Test. As it also complies with section 6.52(a) we conclude that it is compliant with the NFIT.

Test (iii) under best estimate demand scenario

In section C.2 we noted that only Option 1 meets demand over the period 2011-2030 under the best estimate demand forecast. Furthermore, the option of “doing nothing” (Option 8) fails to meet forecast demand.

As the lowest cost option that allows Western Power to meet safety and reliability requirements, Option 1 complies with this limb of the Test. As it also complies with section 6.52(a) we conclude that it is compliant with the NFIT.

C.4 CONCLUSION

Based on the material considered, Option 1 complies with the NFIT on the grounds that it:

- Is the only option that satisfies Section 6.52(a) of the Test; and
- Complies with limbs 6.52(b)(i) and 6.52(b)(iii) of the Test.