363 Wellington Street Perth WA 6000
GPO Box L921 Perth WA 6842
T: 13 10 87 F: (08) 9326 4595
TTY: 1800 13 13 51 TIS: 13 14 50
www.westernpower.com.au
Electricity Networks Corporation ABN 18 540 492 861

Enquiries: Peter Mattner
9326 4556

28 January 2011

Mr Lyndon Rowe
Chairman
Economic Regulation Authority
Level 6, 197 St Georges Terrace
Perth WA 6000

Dear Lyndon

WESTERN POWER RESPONSE TO AUTHORITY'S DRAFT DETERMINATION NFIT PRE-APPROVAL FOR ELECTRICITY SUPPLY TO BINNINGUP DESALINATION PLANT

I am pleased to submit Western Power's response to the Authority's draft determination on the transmission network augmentation in regard to meeting the requirements of the *new facilities investment test*.

This formal submission comprises:

- This covering letter; and
- The attached detailed submission, including the report prepared by NERA Economic Consulting.

Electronic versions are also enclosed, for publication by the Authority.

I look forward to receiving the Authority's final determination on this matter.

Yours sincerely,

PHIL SOUTHWELL
GENERAL MANAGER REGULATION & SUSTAINABILITY

DM# 7904468

Submission to the Economic Regulation Authority

Response to the Draft Determination on the New Facilities Investment Test Application for Transmission Works to Supply the Binningup Desalination Plant

Installation of a second 330/132 kV transformer at Kemerton Terminal and construction of a 132 kV transmission line to supply Binningup Desalination Plant.

DATE: *28 January 2011*

DOCUMENT PREPARED BY:

Western Power
GPO Box L921, Perth WA 6842
ABN 18 540 492 861

safe reliable efficient

Contents

1 Background

1. The Authority published a draft determination on the New Facilities Investment Test Application for Transmission Works to Supply the Binningup Desalination Plant on 21 December 2010. Submissions were invited on the draft determination with a closing date of 21 January, 2011.
2. Western Power sought permission from the Authority to make a late submission with a latest submission date being January 28, 2011. The reasons for the request for the late submission were: "to provide enough time for Western Power to obtain advice from economic consultants to respond to specific issues raised by the Authority in relation to the calculation of net present costs, and quantification of benefits previously unquantified regarding the installation of the 490 MVA transformer".
3. Western Power has sought economic advice to provide Western Power with the capacity to quantify previously unquantified benefits of the 490 MVA rated transformer.

2 Key Points from the Draft Determination:

4. The draft determination was to not approve Western Power's application. This is based on the Authority's determination that the efficient investment cost is $50.53 million, which is $2.1 million less than Western Power's application.
5. The Authority has accepted that "the proposed transmission works represents an efficient choice of project".
6. It is noted that the Authority accepts that in carrying out the transmission works at Kemerton, Western Power has demonstrated that the scope of works, the design, and the delivery of the project, with the exception of the choice of transformer rating, reflects an investment that does not exceed an amount that would be invested by a service provider efficiently minimising costs.
7. Western Power notes that the potential write-down of the cost that meets the efficiency test appears to be based on the actual cost difference between a 250 MVA and a 490 MVA transformer.

3 Western Power approach to its response

8. In the original submission Western Power took the view that there were additional benefits that, on their own, justified the additional cost of the 490 MVA transformer compared to a lower rated transformer.

9. It is noted that the Authority has stated in paragraph 30 that "Western Power has not provided sufficient evidence to demonstrate the design and cost efficiencies associated with its approach to using a standard 490 MVA transformer".

10. In this submission Western Power provides additional information for the Authority's consideration that justifies the choice of transformer rating. To this end Western Power has sought independent advice from economic consultants NERA Economic Consulting. This advice has sought to quantify additional benefits particular to Kemerton that can justify the choice of transformer rating on its own merits.

11. Attached to this submission is a copy of the report from NERA for the Authority's consideration. A summary of the report's conclusions is included within this submission.

12. Western Power notes that the potential write-down of the cost that meets the efficiency test appears to be based on the actual cost difference between a 250 MVA and a 490 MVA transformer. Western Power believes that a write-down, if any, should be based on the difference in net present cost (as distinct to the actual up-front cost) of the option deemed to be the efficient choice and the 490 MVA transformer option.

13. The Authority's technical consultant has suggested in paragraph 25 that an appropriate planning horizon for transmission assets is 10 years. Western Power believes, based on its knowledge and independent technical advice, that the planning horizon for transmission assets should be at least 20 years.

4 Western Power response

4.1 Quantification of additional benefits associated with the 490 MVA rated transformer

14. In its submission dated 1 October 2010, Western Power noted in section 5.2 (p. 12) that "there is an economic value associated with the planning flexibility provided by the additional transformer capacity. This is particularly the case if the load forecasts prove to be conservative."

15. In the original submission, Western Power also makes reference to the existing 132 kV meshed network reaching its capacity and thermal limitations and the aging nature of the lines; noting that most of them were constructed in the 1960s. It further notes that strategically, it has been decided that the future power supply to the Bunbury area will rely on Kemerton Terminal rather than the 132 kV power lines from Muja. The 490 MVA rated transformer is better suited to this strategy than a lower-rated transformer.

16. To quantify the benefits related to planning flexibility, Western Power has sought assistance from NERA. NERA have employed Real Options Analysis (ROA) as the basis to quantify these benefits. ROA allows for the systematic consideration of key uncertainties in relation to the environment within which the investment is being undertaken, the possibility for the business to improve its understanding of these uncertainties over time and different degrees of flexibility for addressing those uncertainties among the investment alternatives being considered.

17. ROA captures the value provided by integrating the ability to adapt long-term network investment plans over time as circumstances change. The in-built flexibility to adjust investment plans over time delivers a quantifiable benefit that is additional to benefits identified under the alternative traditional approach to discounted cash flow analysis. In this particular case, the option created is the opportunity to avoid future costs associated with meeting potential future demand outcomes, either as a result of needing to continue to maintain the Muja-Bunbury Harbour 132 kV line or from needing to upgrade a smaller capacity transformer.

18. NERA's analysis concludes that the 490 MVA alternative has the lowest NPC once future uncertainties, future investment decisions and reduced service costs are explicitly incorporated in the analysis.

4.2 NERA Economic Consulting Work

19. The following is a copy of the conclusion from the NERA report:

> *The Real Options Analysis undertaken by NERA enables the quantification of the potential flexibility provided by alternative investment options at the Kemerton Terminal Station to address uncertainties in the demand and network supply conditions in the Bunbury region over time.*
>
> *The key results from our model can be summarised as follows:*
>
> - *The 490 MVA alternative has the lowest NPC once future uncertainties, future investment decisions and reduced service costs are explicitly incorporated in the assessment. The NPC of the 490 MVA option is $1m lower than that of the 350 MVA alternative and $2m lower than that of the 250 MVA alternative. The intuitive rationale for these results is that the 490 MVA alternative has the flexibility to enable Western Power to avoid costly future network investments as demand and supply conditions evolve.*

- *The 490 MVA alternative also has the lowest NPC risk. Its "worst case" cost of $18m is $4m better than the 350 MVA alternative and $6m better than the 250 MVA alternative. This result is again the result of the flexibility of the 490 MVA alternative to deal with more extreme demand and supply conditions.*

We have undertaken a range of sensitivity tests to examine the robustness of these conclusions to changes in both the value of the underlying parameters used in the model and the assumptions made regarding future uncertainties. The results of these sensitivity tests indicate that the conclusions above are robust to changes in parameter assumptions over a sizable range, and to individual changes in the assumptions made about uncertainties in each period.

4.3 Determination of an asset write-down amount

20. Western Power notes that the potential write-down of the cost that meets the efficiency test appears to be based on the actual cost difference between a 250 MVA and 490 MVA transformer.
21. Western Power believes that the appropriate determination of efficient cost is the present value of the long-run cost of the stream of future investments required to maintain the safety and reliability of the south west interconnected network, not the actual upfront cost of only the initial investment.
22. Writing down the asset value by the full upfront cost difference of the initial investment unreasonably penalises the service provider. This is on the basis that network planning is focused on minimising future costs over the long-term. Having embarked on the first part of the investment plan, which may incur a higher short-run cost but deliver future cost savings, there is no mechanism in place to be compensated for incurring a write-down of this initial cost.[1] This creates a perverse incentive that could drive under-investment and higher long-run cost to consumers.
23. Based on the additional information provided supplementary to the original submission (Analysis of Rating for Second 330/132 kV Transformer Installation at Kemerton Terminal (DM# 7755815)), the associated net present cost analysis demonstrated that the the difference between the 350 MVA and 490 MVA transformer choices is $0.8 million where residual values are included and $0.4 million where residual values are excluded.

4.4 Period of planning horizon

24. The Authority's technical consultant has suggested in paragraph 25 that an appropriate planning horizon for transmission assets is 10 years. Western Power believes that the planning horizon for transmission assets should be 20 years or more in some circumstances.

[1] This is based on the assumption that the additional cost is deemed to be wasteful.

25. Western Power's view is supported by Section 3.9, Suitable Modelling Periods, of the Australian Energy Regulator's "Regulatory investment test for transmission application guidelines"[2] which states:

> "The duration of modelling periods should take into account the size, complexity and expected life of the relevant *credible option* to provide a reasonable indication of the *market benefits* and *costs* of the *credible option*. This means that by the end of the modelling period, the network is in a 'similar state' in relation to needing to meet a similar *identified need* to where it is at the time of the investment.
>
> It is difficult to provide definitive guidance on how this principle should be implemented. However, it is unlikely that a period of less than 5 years would adequately reflect the *market benefits* of any *credible option*. In the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more."

Western Power notes that other transmission network service providers in Australia typically undertake their economic evaluations on a 15-20 year basis, with periods as long as 40 years being adopted in some cases.

As the Binningup Transmission Works are "very long-lived and high-cost investments", a planning horizon of at least 20 years would be more appropriate than 10 years.

[2] This document, dated June 2010, is available at: http://www.aer.gov.au/content/item.phtml?itemId=737903&nodeId=9b856178bc08a9524113e75f129901fe&fn=Final%20RIT-T%20application%20guidelines%20(June%202010).pdf

5 Conclusion

26. Western Power submits the following.

- The forecast costs of the works at Kemerton Terminal reflect those costs that would be incurred by a service provider efficiently minimising costs.
- Net present cost differentials should be the basis of determining any write-down amount related to inefficient investment.
- An appropriate period for the planning horizon for long life transmission investments such as the Kemerton Terminal is at least 20 years.

Appendix 1 – NERA Report – Assessment of the Value of Transmission Works to Supply the Binningup Desalination Plant

28 January 2011

Assessment of the Value of Transmission Works to Supply the Binningup Desalination Plant

A report for Western Power

NERA Economic Consulting

Project Team

Sydney

Adrian Kemp, Associate Director

Ann Whitfield, Associate Director

San Francisco

Adam Borison, Senior Vice President

Philip Narodick, Associate Analyst

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

Contents

List of Tables

List of Figures

1. Introduction

NERA Economic Consulting (NERA) has been asked by Western Power to assess the value created by a proposed investment to upgrade the transmission capability of the network as a consequence of the construction of a desalination plant in Binningup, south of Perth in Western Australia. This request follows the making of a draft determination by the Economic Regulation Authority (ERA) on the application by Western Power to approve proposed new facilities investment in line with the requirements of the Electricity Networks Access Code, 2004 (Access Code).

Specifically, we have been asked to examine the option value associated with the proposed construction of a 490 MVA rated transformer at the Kemerton Terminal, which supplies the Binningup industrial area and the town of Bunbury. This option value might arise if the 490 MVA rated transformer provides additional flexibility to Western Power to address uncertainties in the demand and network supply conditions within the Bunbury region over time.

Our approach to this study has involved a systematic consideration of the network investment decisions available to Western Power to satisfy network supply standards over time, given an identified set of uncertainties. In this broader context, the value of investing now in a 490 MVA transformer is contrasted with potential alternative investment streams for managing the immediate connection of the Binningup desalination plant as well as addressing future supply requirements in the Bunbury region.

Importantly, our study has been completed in a very short timeframe, with this report being finalised two weeks following our engagement. As a consequence of the short timeframe, our study has been based entirely on the information provided to us by Western Power. This has included having access to a number of relevant documents, supplemented by opportunities to discuss the materials provided to us through a series of teleconferences with representatives of Western Power.[1] We have not conducted any independent assessment of the facts or data provided to us and forming the information set for our analysis.

Notwithstanding the assistance that has been provided to us by Western Power, the conclusions in this report are entirely our own.

The remainder of this report is structured as follows:

- Section 2 outlines our understanding of the background of the study;
- Section 3 provides a discussion of the key features of Real Options Analysis (ROA) with a simple example to illustrate the application of this type of analysis to transmission investments;
- Section 4 describes our application of Real Options Analysis, including models and data, to the assessment of the Kemerton Terminal investment alternatives; and
- Section 5 presents our results and conclusions.

---

[1] Our principal contacts within Western Power were Mr Gregory Turnbull, Open Access Engineer, Regulation, and Dr Grant Coble-Neal, Regulatory Economist, Regulation. Expert advice was obtained from within Western Power as required.

2. Background

This section sets out our understanding of the factual circumstances relevant to our consideration of the proposed transmission works. This understanding is based substantially on the material provided in a number of documents, namely:

- Western Power, (2010), Approval of New Facilities Investment – Installation of a second 220/132 kV transformer at Kemerton Terminal and construction of a 132 kV transmission line to supply Binningup Desalination Plant, Submission to the Economic Regulation Authority, 1 October; and
- Economic Regulation Authority, (2011), Draft Determination on the New Facilities Investment Test Application for Transmission Works to Supply the Binningup Desalination Plant, 21 December 2010.

We have also been provided with the underlying Excel spreadsheets and other background documents outlining the assumptions used in the net present cost analysis of the transmission work alternatives considered by Western Power.

2.1. Proposed augmentation

Western Power submitted an application to the ERA on 11 October 2010, for a determination that the proposed transmission network works associated with the connection of the Binningup Desalination Plant satisfies the requirements of the New Facilities Investment Test (NFIT).

The NFIT is set out in section 6.52 of the Access Code, and provides:

6.52 New facilities investment satisfies the new facilities investment test 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.

We understand that the proposed transmission works arise from the proposed installation by the Water Corporation of a desalination plant at Taranto Road, Binningup. To satisfy the supply requirements of the desalination plant, Western Power is proposing the following transmission augmentation works – Table 2.1.

Table 2.1 Components of the proposed transmission augmentation

Section name	Cost of component of augmentation
Binningup 132 kV substation works	$3.3 m
Binningup substation to Kemerton Terminal 132 kV transmission line	$16.53 m
Kemerton Terminal connection of the 132 kV transmission line	$1.5 m
Kemerton Terminal works including installation of a second 330/132 kV transformer and construction of a 132 kV switchyard	$31.3 m
Total cost of augmentation	$52.63 m

As Western Power explains in its submission,[2] the first three items have been classified as dedicated connection assets and so the costs are to be recovered directly from the Water Corporation. The preapproval application to the ERA therefore only applies to the Kemerton Terminal works.

Of the proposed $31.3 million for the Kemerton Terminal works, $25.3 million is the cost of constructing the terminal works in 2013/14, which Western Power has forecast would be needed in the absence of the desalination plant load, given expectations about future demand growth. The additional $6 million reflects the cost of bringing forward the proposed works to 2010/11 in order to meet the timing requested in the Water Corporation's Network Access Application for the desalination plant.

2.2. Rationale for installation of a 490 MVA rated transformer

Western Power undertook an assessment of forecast load in the Bunbury service area, and determined when transformer investment would have been required in the absence of the desalination plant. The approach used by Western Power for its load forecasts involved:[3]

- developing a natural load growth forecast, based on projecting forward the historical trend growth;
- developing load forecast cases according to the degree of inclusion of anticipated future block loads, namely:

---

2 See Western Power's submission, page 5.

3 A fuller discussion of the approach used by Western Power on load forecasts is set out in the Binningup Desalination Plant Planning Report.

– a low case – being the sum of natural load growth plus the additional load associated with only the first stage of the Binningup desalination plant;

– a central case – being the sum of natural load growth and prospective block load growth, based on a probability of the load growth coming on line;

– a high case – being the sum of natural load growth plus all prospective block load growth.

Western Power investigated the installation of a 250 MVA, 350 MVA, or a 490 MVA transformer under each of the load forecast cases. As part of this investigation Western Power determined the timeframe within which the capacity of the transformer would be exceeded, resulting in the incurrence of additional costs of upgrading the transformer. The resultant net present cost estimates are summarised in table 2.2.

Table 2.2 Net present cost for installation of different rate transformers at Kemerton Terminal

Options	NPC in $ million		
	High	Central	Low
Option 1: Install a 490 MVA transformer	10.3	10.1	9.7
Option 2: Install a 250 MVA transformer replaced by a 490 MVA	10.0	9.3	8.9
Option 3: Install a 350 MVA transformer replaced by a 490 MVA	9.8	9.3	9.2
Option 4: Install a 250 MVA transformer and then a third 250 MVA when required	11.8	10.8	9.8

In identifying the 490 MVA transformer as the most appropriate alternative, rather than the alternative smaller size transformers, Western Power noted that:[4]

- it receives benefits from standardisation of transformer size across its network, as the resulting full inter-changeability of units allows it to cover the risk of catastrophic failure without incurring the carrying costs of maintaining a spare unit;
- there is economic value associated with the planning flexibility provided by the additional capacity associated with the 490 MVA transformer; and
- the cost difference between the various alternatives is less than 10 per cent, which does not provide sufficient justification to introduce a different size transformer to that used in all other terminal stations.

[4] See Western Power's submission, p. 12.

2.3. Draft determination by Economic Regulation Authority

The ERA issued its draft determination in relation to Western Power's submission on 21 December 2010. The ERA has indicated that there are cost savings of $2.1 million if Western Power had constructed a lower rated transformer.

The principal arguments made by the ERA are:

- that it accepts the advice of its own consultant that a cost differential of 10 per cent is sufficiently material so as to warrant concern (despite the possible presence of unquantified benefits) and is likely to outweigh any benefits from standardising transformers;
- that Western Power's own analysis indicates that the estimated cost of a 250 MVA and 350 MVA transformer are 77 per cent and 88 per cent respectively lower than a 490 MVA transformer;
- that a more prudent approach to standardisation of transformer sizes would be to have a number of standards, rather than the current one size fits all approach, because Western Power has been unable to quantify the benefits from its current approach and thereby demonstrate that the benefits outweigh the costs; and
- that the proposed cost of $31.3 million is greater than would be invested by a service provider efficiently minimising costs, and so should be reduced by $2.1 million.

3. Real Options Analysis

The net present cost analysis undertaken by Western Power and presented in its submission to the ERA is based on sound principles. It is a traditional approach to investment assessment undertaken by many businesses. However, this type of analysis by itself is not well suited to capturing the differences in potential costs between alternatives in circumstances in which there are:

1. significant uncertainties in relation to key aspects of the future environment within which the investment is being undertaken;
2. possibilities for the business improving its understanding of these uncertainties over time; and
3. different degrees of flexibility for addressing these uncertainties among the investment alternatives being considered.

For this reason, many businesses have moved to adopt alternative valuation techniques, including Real Options Analysis (ROA).[5] Further information on businesses which have adopted this approach, including in Australia, is provided below in section 3.1.

From our review of the submission materials and from subsequent discussions with Western Power we have identified that the assessment undertaken by Western Power:

- did not fully consider the extent of future uncertainty in relation to natural load growth, future block load and generation additions, and the possibility of necessary decommissioning of the Muja to Bunbury line;
- did not fully incorporate the flexibility that different investment decision alternatives have to respond to these uncertainties, and the impact that different alternatives have on future investment decisions; and
- did not formally capture all the current and future costs of different decision alternatives over time, including the cost of reduced service (eg, unserved energy).

NERA has been asked by Western Power to apply a methodology that does address these issues. This remainder of this section describes this methodology - Real Options Analysis - in general terms, using a simple illustrative (but representative) transmission investment example. Section 4 then describes the application of this methodology to assess the costs of different investment alternatives at Kemerton Terminal, including the installation of a 490 MVA transformer. Section 5 describes the results of this application.

---

[5] See, for example, A. Triantis and A. Borison, *Real Options: State of the Practice*, Journal of Applied Corporate Finance, Sum 2001.

3.1. Use of ROA

The term ‘real options’ was coined by Stewart Myers in 1977. It refers to the application of option pricing theory to the valuation of investments in non-financial (or ‘real’) assets, where much of the value is attributable to flexibility and learning over time.

Real options began to attract serious attention in capital-intensive industries in the 1990s. Beginning principally in the oil and gas industry and then extending to a range of other industries, management consultants and internal analysts began to apply real options to major corporate investments. Leading energy, industrial and service firms, such as Aetna, Chevron, DuPont and Procter & Gamble all adopted real options to varying degrees. Real options also garnered interest from government agencies and research institutions such as the US Department of Energy, the UK Council for Science and Technology and the Electric Power Research Institute. Major consulting firms such as Monitor and PricewaterhouseCoopers established formal real options practices.

Currently, a wide range of private and public sector organizations continue to apply and adopt real options. Real options is particularly popular in the energy sector given the magnitude of both the capital involved and the uncertainties faced in that industry. Some of the major energy companies using real options include Chevron, EdF, Pacific Gas and Electric, Shell and Tennessee Valley Authority.

In Australia, Real Options Analysis is being used by:

- BHP Billiton (see Peter H.L. Monkhouse, The Costs and Benefits of Part IIIA, Proceedings of the 2007 ACCC Regulatory Conference)
- CSIRO (see Zili Zhu and Peter Moran, Selecting The Right Technology for Future Generation, September 2010)
- Water Supply Association of Australia (see Submission to National Water Commission, 2011 Biennial Assessment, November 2010)

The applicability of Real Options Analysis to electricity transmission investment has also been explicitly recognised in Australia following the Australian Energy Market Commission’s (AEMC) 2009 review of the regulatory test (now known as the Regulatory Investment Test for Transmission, or RIT-T).[6] The AEMC indicated that consideration of Option Value: ‘May facilitate a more strategic view of projects.’[7] As a consequence, the National Electricity Rules applying in the National Electricity Market now explicitly require transmission businesses to consider option value as one of the potential benefits associated with a transmission investment.[8]

---

6 AEMC, *National Electricity Amendment (Regulatory Test for Transmission) Rule 2009 - Final Rule Determination*, June 2009.

7 Op cit, p. 17.

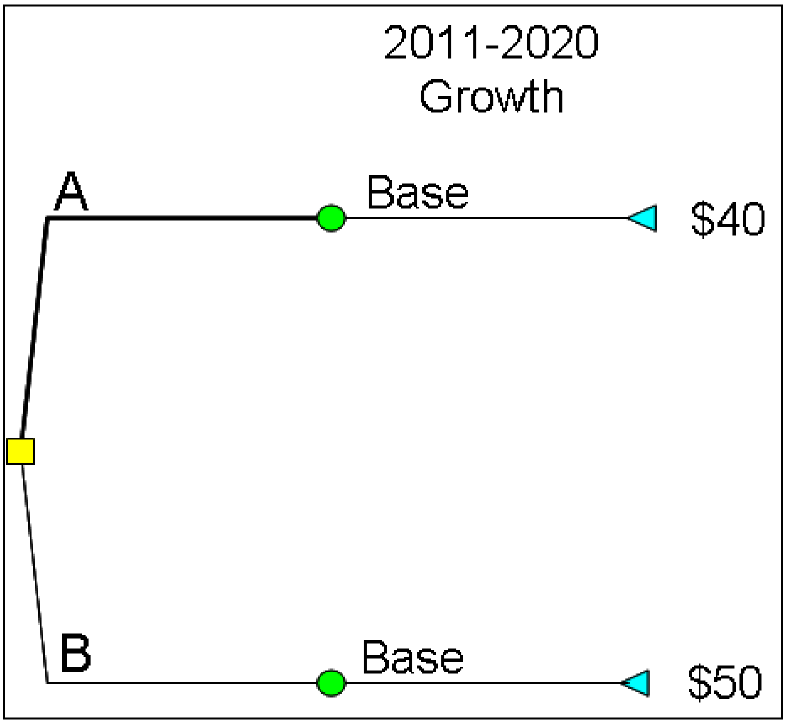
8 National Electricity Rules, 5.6.5B(c) (6) (ix).

3.2. Traditional Analysis

Transmission investments involve capital and operating costs, and create market benefits through improved service such as reduced unserved energy, increased transfer capability, lowered network congestion and the like. Traditionally, transmission investments are valued by determining the net present cost (NPC) for a specified minimum level of service, or by determining the net present cost (NPC) of all costs and benefits including different service levels. Investment alternatives are then selected by comparing the NPC of fixed (unchanging) investment alternatives in a single fixed (unchanging) scenario of future events (or perhaps a few such scenarios) over a forecast period.

This traditional methodology is illustrated in Figure 3.1 where two alternatives, Alternative A and B, are compared in a single forecast or “base” scenario of demand growth over ten years. In this figure, the yellow square represents a decision, the green ovals represent uncertainties and the blue triangle represents the end of each tree path where the impact is determined. In this example, the NPC of Alternative A is $40m and the NPC of Alternative B is $50m. Based on a minimum cost criterion, Alternative A is preferred (indicated in the figure by the heavier line for this alternative). Western Power adopted this type of traditional analysis in its earlier submission.

Figure 3.1
Traditional NPC Analysis



Note: dollar figures represent millions of dollars

Traditional analysis takes the perspective that investments are largely fixed; that is, the business commits to an alternative over the forecast horizon and it is not adapted to changing conditions over time. It also characterises the investment environment as largely fixed; that is, it can be described by a few unchanging scenarios.

Real Options Analysis takes a broader and more realistic perspective, and extends the traditional methodology in three important dimensions:

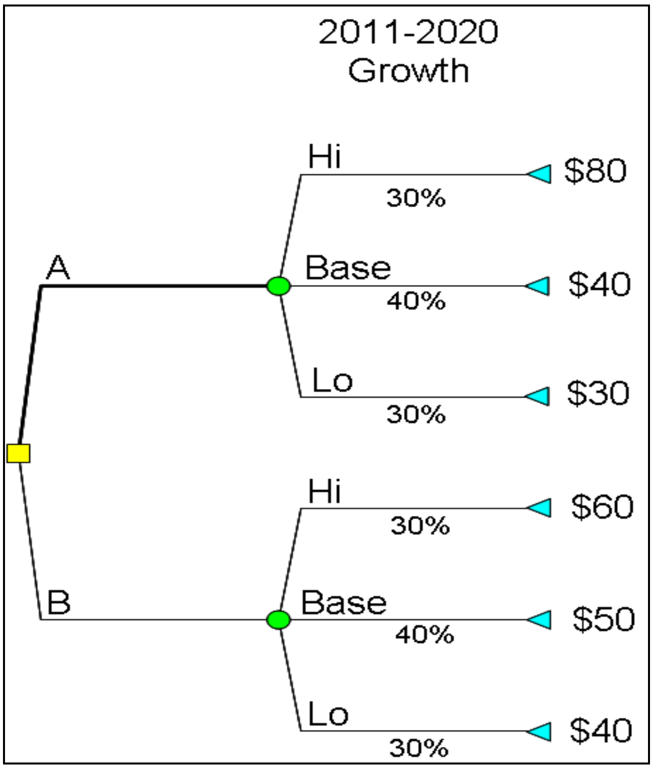
1. First, **uncertainty**. The value of a transmission investment alternative can depend greatly on the outcome of a wide range of possible future demand, supply and other events. Some alternatives deal well with one set of circumstances, while other alternatives deal well with another different set of circumstances. Real Options Analysis considers a comprehensive range of individual events and their dependence relationships to generate numerous changing (and more realistic) scenarios, not just one or a few unchanging scenarios.
2. Second, **learning**. The value of a transmission investment alternative can depend greatly not just on the current level of uncertainty, but on how understanding regarding that uncertainty changes over time. Some alternatives are highly sensitive to the outcome of uncertainties over time; others are more robust – performing well across a wide range of circumstances. Real Options Analysis not only incorporates uncertainty, but also this changing state of information over time.
3. Third, **flexibility.** The value of an investment alternative can depend not only on uncertainty and learning, but on the ability to respond to that learning if that alternative is chosen. Some alternatives can be adjusted (eg., accelerated, decelerated, abandoned) as new information is gained and circumstances are clarified; others can only be adjusted with great difficulty. Real Options Analysis explicitly incorporates this important ability to adapt over time.

Because Real Options Analysis addresses issues typically ignored in traditional analysis, the results and conclusions can differ significantly. Of course, not all transmission investment issues are affected equally by uncertainty, learning and flexibility. Generally, the greater the uncertainty, learning and flexibility, the greater the differences between traditional and Real Options Analysis. The steps involved in extending traditional fixed NPC valuation to full Real Options Analysis are described in more detail below using the simple Alternative A vs. Alternative B example above.

3.3. Uncertainty Analysis

Figure 3.2 illustrates how the fixed NPC analysis illustrated in Figure 3.1 is extended to more fully incorporate uncertainty. In this example, the two alternative options are fixed as in Figure 3.1; that is, the business must commit to one or the other for the entire forecast horizon without variation. However, future demand is no longer limited to a single base scenario. Instead, it is uncertain and is characterized by three scenarios (Hi, Base and Lo) that extend over the entire 10 year time horizon. In this example, the probabilities of Hi, Base and Lo are 0.3, 0.4 and 0.3 respectively.

Figure 3.2
Incorporating Uncertainty



Note: dollar figures represent millions of dollars

Figure 3.2 shows the NPC of each alternative (ie, Alternative A or Alternative B) in each scenario (ie, Hi, Base or Lo). In this example, Alternative A costs $80m in the Hi case, $40m in the Base case (as in Figure 1), and $30m in the Lo case. Alternative B costs $60m in the Hi case, $50m in the Base case, and $40m in the Lo case. It is worthwhile noting that these figures incorporate all the costs associated with each path through the tree, including the capital costs of Alternatives A and B as well as any other costs incurred as a result of the less than perfect match between the alternative chosen and the resulting demand. This "less than perfect" match is a natural result of decision-making under uncertainty where the future is known only imperfectly when decisions are made. By and large, this is a more realistic view of the investment environment.

The generally-accepted criterion for making investment decisions such as this one in the face of uncertainty is expected or probability-weighted cost minimization.[9] In this case, the expected cost given Alternative A is $49m and the expected value given Alternative B is $50m. Note that by explicitly incorporating uncertainty into the analysis, the difference in net present cost has decreased from $10m to $1m. Alternative A is still preferred (as indicated by the heavier line), although now by a much smaller margin than in the Figure 3.1. The difference between the

[9] See, for example, Danny Samson, Managerial Decision Analysis, 1988, p. 155.

results in Figure 3.1 and Figure 3.2 represents the improved accuracy of the investment analysis achieved by explicitly considering uncertainty in more detail.

Of course, this example is illustrative and the nature of the uncertainty in a real application may be different. For example, in a more realistic application, there are likely to be multiple uncertainties over multiple time periods.

3.4. Learning Analysis

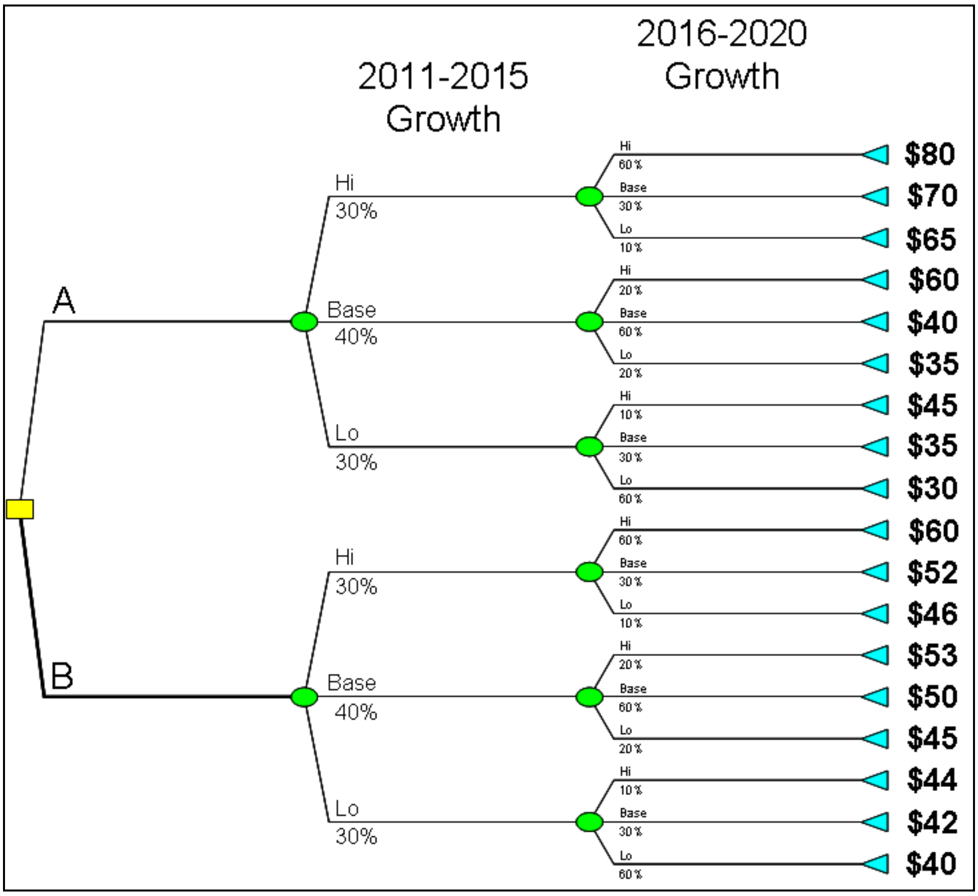
Figure 3.3 illustrates how the uncertainty analysis in Figure 3.2 is enhanced to reflect learning. By learning, we mean that uncertainty is not static but dynamic, ie, it changes over time. Our state of information (ie, our understanding) can change.

As in Figure 3.2, demand growth can be Hi, Base or Lo. However, the state of information about demand varies (and actually improves) over time. In this example, if the demand is Hi (or Lo) during the first five years, the chance that demand will remain Hi (or Lo) in the subsequent period increases. Our forecasts become more accurate. For example, if demand is Hi during the first five years, the probability of demand being Hi in the second five years rises to 60%, with only a 10% chance of demand becoming Lo). With this learning, there are now 9 demand “scenarios” rather than 3 against which each alternative must be assessed. For example, one scenario is “Hi” for five years and “Lo” for five years.

Figure 3.3 shows the NPC of each alternative for each of these 9 demand scenarios. As before, the cost of Alternative A in the case of high demand for the entire ten-year forecast period or “Hi, Hi” is $80m. Similarly, the cost of Alternative B in the “Lo, Lo” case remains $40M. With this more detailed, dynamic treatment of uncertainty, the expected NPC for Alternative A is now $49.5m, and for Alternative B $49.0m. On the basis of expected NPC, Alternative B is now the preferred choice although the costs of the two alternatives are nearly identical. This preferred choice is indicated by the heavier line in the figure associated with Alternative B. The difference in the results between Figure 3.3 and Figure 3.2 (and Figure 3.1) represents the improved accuracy associated with a more comprehensive model of uncertainty incorporating learning or dynamics.

Again, this example is illustrative and the nature of the learning in a real application may be different. In a more realistic application, it is likely that some uncertainties will exhibit positive correlations over time as in this example (eg., Hi in one period increases the likelihood of Hi in the next period), others may show negative correlations (eg., Hi in one period decreases the likelihood of Hi in the next period), and still others may be uncorrelated.

Figure 3.3
Incorporating Learning



Note: dollar figures represent millions of dollars

3.5. Flexibility Analysis

Figure 3.4 illustrates how the learning analysis in Figure 3.1 is extended to incorporate flexibility; that is, the ability to adapt or adjust decisions over time. As in Figure 3.3, uncertainty is dynamic. The difference here is not just that uncertainty is dynamic; investments are as well.

Each investment has been divided into two stages. A1 refers to the adoption of Alternative A in the first five years, while A2 refers to the adoption of Alternative A in the second five years. The two fixed alternatives remain, choosing A or B for the entire ten years (A1 followed by A2, and B1 followed by B2). However, there are now two more alternatives – starting with Alternative A in the first period (A1) and switching to Alternative B in the second period (B2) or starting with Alternative B in the first period (B1) and switching to Alternative A in the second period (A2). The decision to switch, and the value gained by switching, is the direct result of the learning that is achieved over time regarding how the currently uncertain future may evolve. Of course, the decision to switch may have costs as well as benefits.

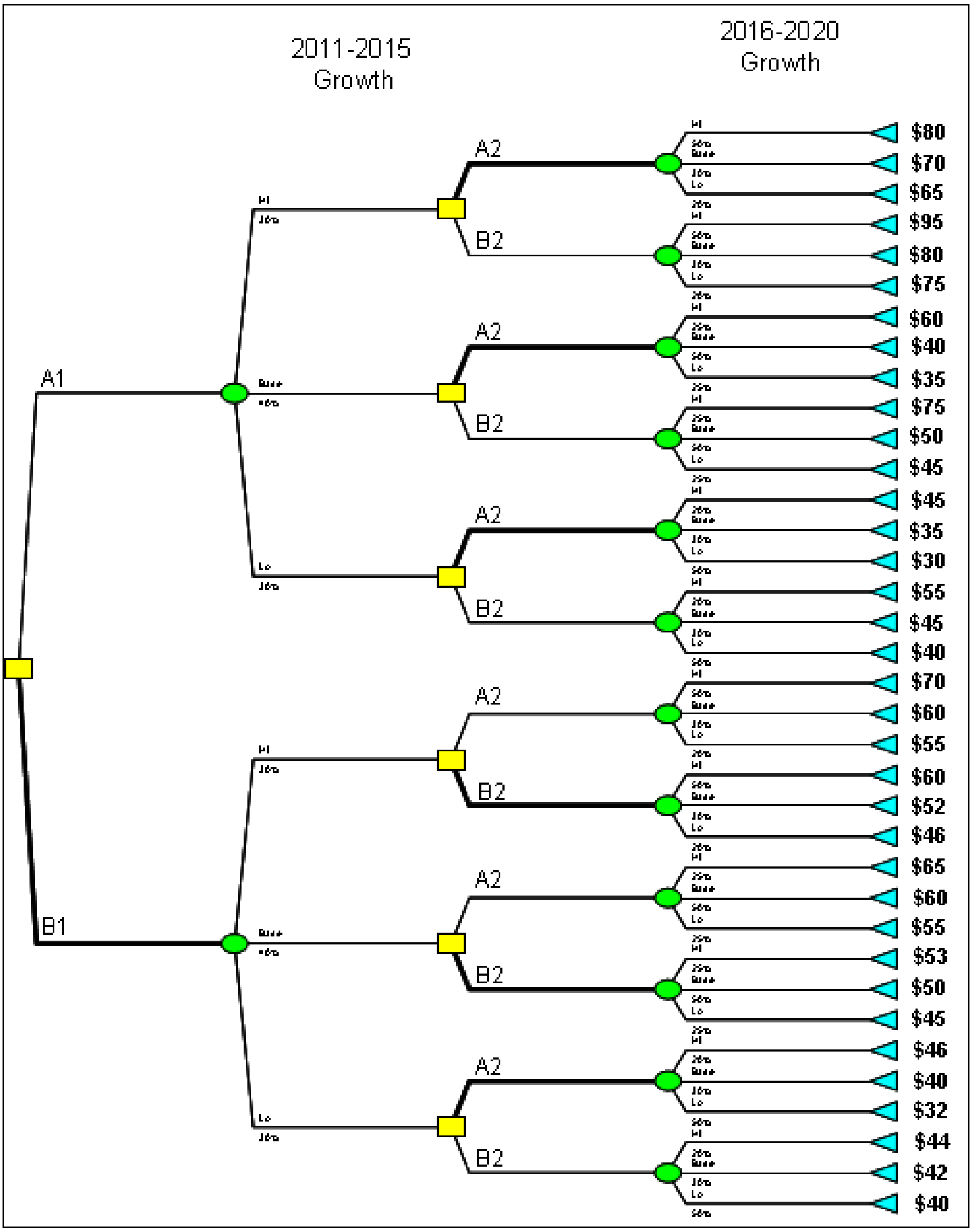
As Figure 3.4 illustrates, the decision when this flexibility perspective is taken is not whether or not simply to proceed fully with Alternative A or Alternative B over the entire forecast horizon – "all or nothing." Instead, the decision is which initial stage (A1 or B1) to choose. After the initial decision, there are future or "downstream" decisions regarding staying with the original choice or switching. The single investment decision has become an investment plan of adapting to changing circumstances over time. The current and future decisions interact. The choice of a current alternative may affect the ability to choose future alternatives. The existence of future alternatives may affect the choice of current alternatives.

The top half of the figure shows the results when Alternative A is adopted in the first period. As the heavier lines associated with A2 indicate, there is never any reduced cost associated with switching. In all cases, choosing B2 (switching) over A2 (not switching) is more expensive. Consequently, the overall cost of Alternative A in the initial stage remains as before: $49.5m.

The bottom half of the figure shows the results when Alternative B is adopted in the first stage. As the heavier lines indicate, the story here is quite different. If demand turns out to be Hi or Base, there is no value in switching to A. However, if demand turns out to be Lo, considerable cost savings can be achieved by switching. Consequently, the overall cost of the initial Alternative B choice is no longer $49.0m but $47.7m. Including the cost of switching, the preferred alternative is to begin with Alternative B in the first period, to stick with Alternative B if demand is Hi or Base, but to switch to Alternative A if demand is Lo. This flexible plan will save more than $1m over fixed Alternative B and nearly $2m over fixed Alternative A. The consideration of future alternatives and the ability to choose those alternatives affected both the strategy and the value.

Yet again, this example is illustrative and the nature of flexibility may be different in a real application. In a more realistic application for example, this flexibility value may come from the ability to switch alternatives as in this example, the ability to increase or decrease future investments, or the ability to accelerate, decelerate or abandon them.

Figure 3.4
Incorporating Flexibility



Note: dollar figures represent millions of dollars

3.6. Conclusion

Table 3.1 below summarizes the results of the different forms of analysis described above. As the table indicates, there can be considerable differences both in numerical results – valuation – and in recommended choices - strategy.

Table 3.1
Results from Different Types of Analysis

Type of Analysis	Cost of A	Cost of B	Recommendation
Fixed (Traditional)	$40M	$50M	A
Uncertainty	$49M	$50M	A
Learning	$49.50M	$49.00M	B
Flexibility (Real Options Analysis)	$49.50M	$47.74M	Start with B but switch to A in Lo case

In this example, traditional fixed analysis indicated that Alternative A was preferred by a margin of $10m over Alternative B. Uncertainty and learning analysis indicated that the two alternatives were much closer, and that Alternative B might actually be preferred. Finally, flexibility or Real Options Analysis indicated that the alternative of starting with B but switching to A under appropriate circumstances was preferred on an expected cost basis by $1m to $2m.

While this example is simple and illustrative, the analysis and results are applicable in practice. Full incorporation of uncertainty, learning and flexibility in the form of Real Options Analysis can lead to considerably different results than traditional analysis.

4. Applying Real Options Analysis to Kemerton Terminal Investment Alternatives

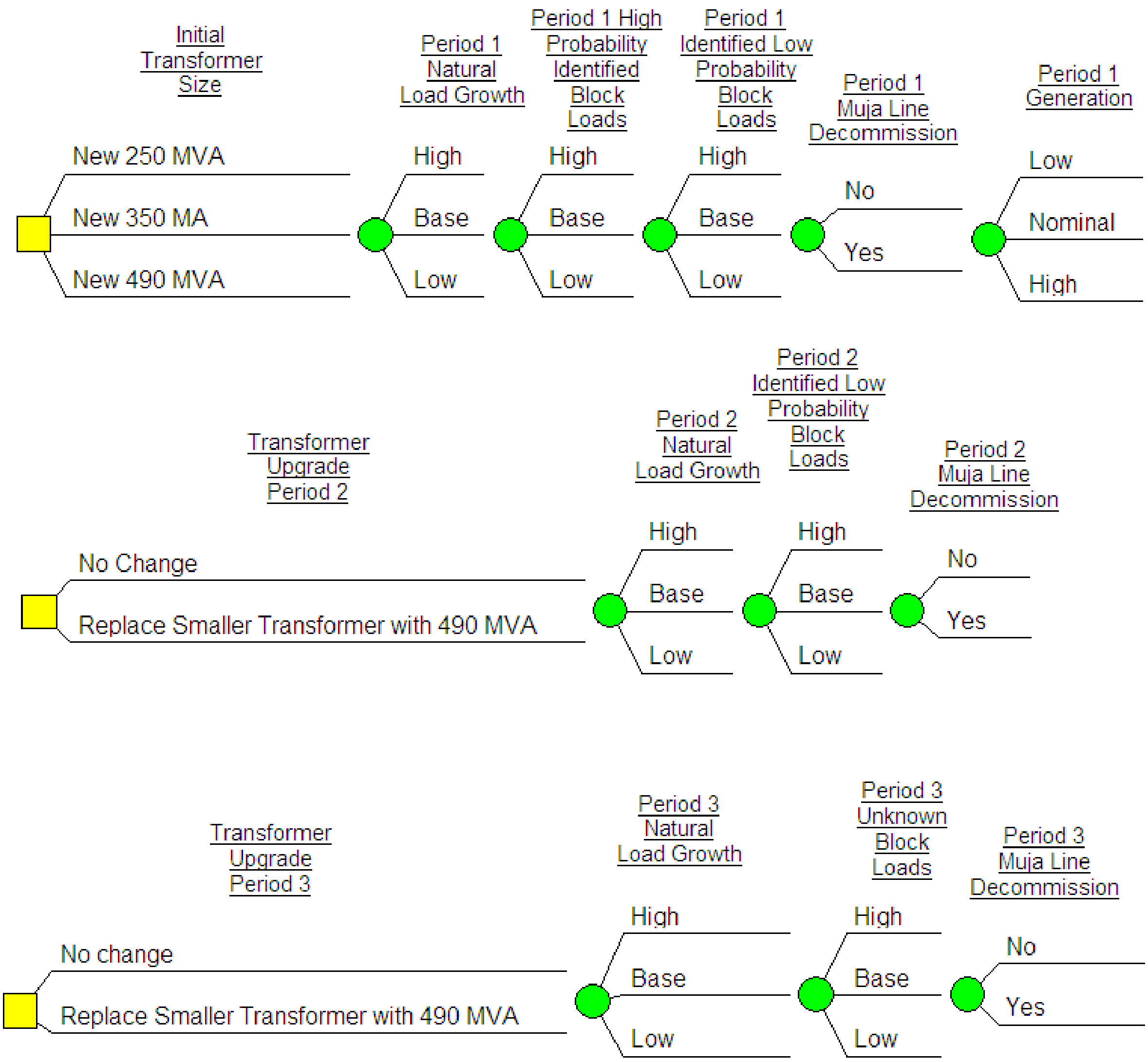
As noted at the beginning of Section 3, Western Power's traditional NPC analysis of the Kemerton terminal transmission investment alternatives did not fully address some key issues: the extent and timing of uncertainties in future load growth and block load and generation additions, the flexibility of different investment alternatives to be adjusted to changing circumstances, and the full range of future impacts of the alternative investments. Western Power highlighted in its earlier submission to the ERA that there was economic value associated with the additional flexibility provided by the 490 MVA transformer. However this flexibility was not formally quantified as part of Western Power's earlier assessment.

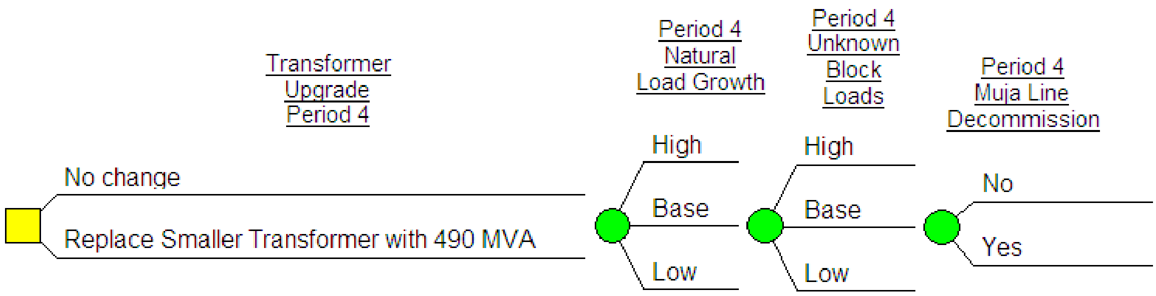
NERA has now been asked by Western Power to apply Real Options Analysis (ROA) in order to better address these important issues. In practice, ROA involves the use of two separate but linked models. A "scenario" model is used to capture the evolution of decisions and uncertainties over time, typically in the form of a decision tree. An "impact" model is used to estimate the cost (or benefit) associated with each scenario. Together, these models generate the results of interest, particularly the expected cost and risk of each alternative. Each of these two models is described below. Results from the modelling effort are provided in Section 5.

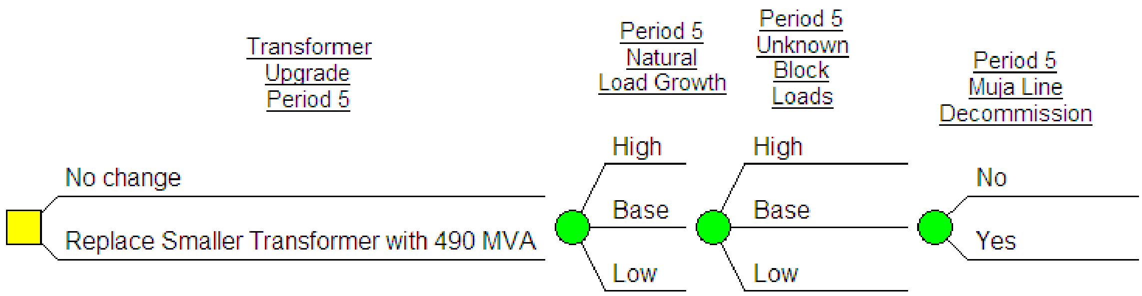
4.1. Scenario Model

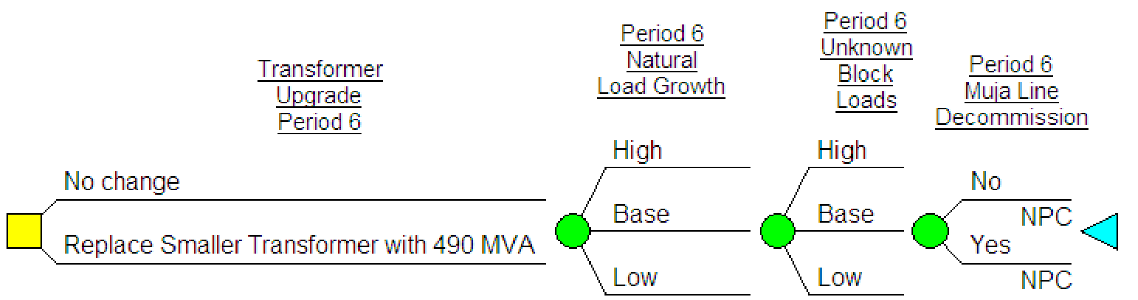
Figure 4.1 shows the scenario model developed for the Kemerton Terminal Assessment. As described earlier, ROA does not focus on a single immediate decision or a single scenario. Instead, it incorporates numerous decisions and uncertainties over time. In the full ROA model, there are six decisions (yellow squares) each with decision alternatives, and nineteen uncertainties (green ovals) each with uncertainty outcomes. Because of the number of paths in this tree, this figure is shown in compact or schematic form. If fully connected, the tree would include millions of paths. The major elements of the decision tree are described in more detail below.

Figure 4.1
Scenario Model









4.1.1. Decisions and decision alternatives

In ROA, it is important not only to specify the immediate decision alternatives but the future (or downstream) decision alternatives as well. Choices made now may open or close opportunities in the future. The existence of opportunities in the future may affect the wisdom of choices made now. As load growth continues into the future, and as further block loads come onto the system (including the potential expansion of the desalination plant), Western Power will face further investment decisions in relation to capacity at the Kemerton Terminal. These future decisions may have implications for the choice of current investment, and so need to be captured within the model. This is the 'flexibility' aspect of the ROA model.

It also important in ROA not to overly constrain the alternatives associated with each decision but to include a wide range of possibilities. Including an alternative does not mean that it is advisable, only that it is feasible. The results of the analysis will determine whether a particular alternative is advisable or not.

In our model, we incorporated decisions at six points in time: Current, 2016, 2021, 2026, 2031 and 2036. The specific future dates are representative; in practice, decisions may occur on those dates or others. These representative dates effectively capture the range of future decisions, and the impact that those decisions can have on the choice of current investment alternatives.

The Current decision point captures the immediate investment alternatives: ie, the potential alternative transformer capacities that could be installed at the Kemerton Terminal station. As noted above, the future decision points are designed to capture alternatives that will be considered over time as uncertainties, such as the potential future expansion of the Binningup desalination plant or decommissioning of the Muja-Bunbury line, are resolved.[10] The alternatives associated with each decision are shown in Figure 4.2 below. Like the specific dates, these alternatives are representative. In practice, the future network reinforcement decisions may involve additional transformer capacity or other network reinforcements.

Figure 4.2
Decision Alternatives

Current Decision	Decision 2016	Decision 2021
250 MVA Transformer	No Change	No Change
350 MVA Transformer	Replace Smaller with 250MVA	Replace Smaller with 250MVA
490 MVA Transformer	Replace Smaller with 350MVA	Replace Smaller with 350MVA
	Replace Smaller with 490MVA	Replace Smaller with 490MVA

Decision 2026	Decision 2031	Decision 2036
No Change	No Change	No Change
Replace Smaller with 250MVA	Replace Smaller with 250MVA	Replace Smaller with 250MVA
Replace Smaller with 350MVA	Replace Smaller with 350MVA	Replace Smaller with 350MVA
Replace Smaller with 490MVA	Replace Smaller with 490MVA	Replace Smaller with 490MVA
New 490MVA	New 490MVA	New 490MVA

Current Decision captures the immediate question: should Western Power install a 250, 350, or 490 MVA transformer at the Kemerton Terminal Station. This is the issue facing the ERA now, in making its determination on Western Power’s submission.

Decision 2016 and **Decision 2021** represent near-term future decisions that may play a role in this current decision. At these future points, Western Power may choose not to install any additional capacity (No Change) or to replace a smaller transformer at Kemerton with a 250 MVA, 350 MVA or 490 MVA transformer. ‘Smaller’ refers to the size of the two transformers at Kemerton. In most cases, this would be the original 225 MVA transformer. In cases where

10 These uncertainties are discussed further in section 4.1.2.

the Current Decision is to install a 250 MVA or 350 MVA transformer, it could also be replacement of this transformer.

Decision 2026, **Decision 2031** and **Decision 2036** represent long-term future decisions that may also place a role in the current decision. At these future points, Western Power may choose not to install additional capacity, to replace a smaller transformer (as discussed above), or to add an additional 3rd transformer at Kemerton (at an additional cost).

4.1.2. Uncertainties and Uncertainty Outcomes

In ROA, it is important not only to specify one or two future scenarios, but to incorporate the full set of relevant uncertainties, their relationships and the learning that takes place about their evolution over time.

Based on a review of documents and discussions with Western Power, we identified five uncertainties that could significantly affect the choice among investment alternatives, and how Western Power's assessment of these uncertainties may change over time (ie, the 'learning' component of the analysis).

Our model allows for these uncertainties to appear in one or more of six time periods: Current – 2015, 2016-2020, 2021-2025, 2026-2030, 2031-2035, 2036-2040. For each uncertainty, there may be different forms and levels of learning over these time periods.

- **Natural load growth.** Natural load growth refers to underlying residential and commercial demand. Western Power provided an assessment of the possible growth rates for natural load during the six periods based on its Summer Load Trends Report 2009-2028. Western Power also indicated that loads in subsequent periods are negatively-correlated; that is, high load growth in one period implies lower load growth in subsequent periods and vice versa. The learning incorporated within the model therefore reflects this negative correlation. This negative correlation tends to reduce the possibility of extreme high or low outcomes, and can be thought of as a conservative assumption with respect to growth.

- **Previously-identified block loads.** In its October submission to the ERA, Western Power identified several specific block loads that had a high-probability of occurring. Western Power provided NERA with a more detailed assessment of the size, timing and likelihood of each of these block loads, and their dependence on underlying economic and natural load growth. We processed this information into a probability distribution on the previously-identified block load capacity added in each period. Western Power also indicated that loads were negatively-correlated; that is, if these block load additions did not arrive in Period 1, they would arrive in Period 2. The learning within the model reflects this negative correlation.

- **Newly-identified block loads and generators**. In addition to the previously identified block loads, Western Power identified several other lower-probability block loads and generators in Period 2. We have included these in our analysis. Western Power provided an assessment of the size, timing and likelihood of each of these block additions, and their dependence on underlying economic and natural load growth. We processed this information into a probability distribution on newly-identified block load and generator capacity added in Period 2. Western Power also indicated that these additions depend on underlying natural load and economic growth but are uncorrelated; that is, additions in each period are independent. This lack of learning is reflected in the model.

- **Unidentified block loads and generators**. In addition to identified block loads and generators in Periods 1 and 2, Western Power indicated that currently-unidentified block loads and generators could be added during Periods 3 through 6. Western Power assessed that these additions were uncertain but that the amount was likely to be the same as the newly-identified block loads and generators in Period 2. The amount is independent each period without learning, but depends on underlying natural load and economic growth. This lack of learning is reflected in the model.

- **Muja to Bunbury Harbour line decommissioning**. In addition to natural load growth, and block loads and generators, Western Power indicated that decommissioning of the Muja-Bunbury Harbour line could affect the available capacity at Kemerton. Western Power assessed the probability of this decommissioning in each of the six periods. The probability of decommissioning increases with time. Perhaps obviously, the outcomes here are highly-negatively correlated. If decommissioning occurs in one period, it cannot occur in subsequent periods. This learning is reflected in the model.

Of the five uncertainties listed above, only the first two were examined explicitly in the earlier NPC analysis undertaken by Western Power.

The specific outcomes and probabilities for these uncertainties are shown in Figure 4.3 through Figure 4.7 below.

Figure 4.3
Natural Load Growth

Natural Load Growth		Values (annual multiplier)	Probabilities
Period 1	High	1.055	0.3
	Base	1.035	0.4
	Low	1.025	0.3

Natural Load Growth (Depends on Period 1 Natural Load Growth)		Values (annual multiplier)	Probabilities
Period 2 (Given High Natural Load Growth Period 1)	High	1.055	0.2
	Base	1.035	0.3
	Low	1.025	0.5
Period 2 (Given Base Natural Load Growth Period 1)	High	1.055	0.3
	Base	1.035	0.4
	Low	1.025	0.3
Period 2 (Given Low Natural Load Growth Period 1)	High	1.055	0.5
	Base	1.035	0.3
	Low	1.025	0.2

Natural Load Growth (Depends on Period 2)		Values (annual multiplier)	Probabilities
Period 3 (Given High Natural Load Growth Period 2)	High	1.055	0.2
	Base	1.035	0.3
	Low	1.025	0.5
Period 3 (Given Base Natural Load Growth Period 2)	High	1.055	0.3
	Base	1.035	0.4
	Low	1.025	0.3
Period 3 (Given Low Natural Load Growth Period 2)	High	1.055	0.5
	Base	1.035	0.3
	Low	1.025	0.2

Natural Load Growth (Depends on Period 3)		Values (annual multiplier)	Probabilities
Period 4 (Given High Natural Load Growth Period 3)	High	1.055	0.2
	Base	1.035	0.3
	Low	1.025	0.5
Period 4 (Given Base Natural Load Growth Period 3)	High	1.055	0.3
	Base	1.035	0.4
	Low	1.025	0.3
Period 4 (Given Low Natural Load Growth Period 3)	High	1.055	0.5
	Base	1.035	0.3
	Low	1.025	0.2

Natural Load Growth (Depends on Period 4)		Values (annual multiplier)	Probabilities
Period 5 (Given High Natural Load Growth Period 4)	High	1.055	0.2
	Base	1.035	0.3
	Low	1.025	0.5
Period 5 (Given Base Natural Load Growth Period 4)	High	1.055	0.3
	Base	1.035	0.4
	Low	1.025	0.3
Period 5 (Given Low Natural Load Growth Period 4)	High	1.055	0.5
	Base	1.035	0.3
	Low	1.025	0.2

Natural Load Growth (Depends on Period 5)		Values (annual multiplier)	Probabilities
Period 6 (Given High Natural Load Growth Period 5)	High	1.055	0.2
	Base	1.035	0.3
	Low	1.025	0.5
Period 6 (Given Base Natural Load Growth Period 5)	High	1.055	0.3
	Base	1.035	0.4
	Low	1.025	0.3
Period 6 (Given Low Natural Load Growth Period 5)	High	1.055	0.5
	Base	1.035	0.3
	Low	1.025	0.2

Figure 4.4
Previously Identified Block Loads

Previously Identified Block Loads (Period 1)		Values (MW)	Probabilities
Period 1 (Given High Demand Period 1)	High	155	0.3
	Base	155	0.4
	Low	155	0.3
Period 1 (Given Base Demand Period 1)	High	132	0.3
	Base	88	0.4
	Low	43	0.3
Period 1 (Given Low Demand Period 1)	High	26	0.3
	Base	26	0.4
	Low	26	0.3

Figure 4.5
Newly Identified Block Loads and Generators

Newly Identified Loads and Generators (Period 1)		Values (MW)	Probabilities
Period 1 (Given High Demand Period 1)	High	4	0.3
	Base	-40	0.4
	Low	-82	0.3
Period 1 (Given Base Demand Period 1)	High	9	0.3
	Base	-32	0.4
	Low	-75	0.3
Period 1 (Given Low Demand Period 1)	High	8	0.3
	Base	-1	0.4
	Low	-43	0.3

Newly Identified Loads and Generators (Period 2)		Values (MW)	Probabilities
Period 2 (Given High Demand Period 2)	High	101	0.3
	Base	52	0.4
	Low	-47	0.3
Period 2 (Given Base Demand Period 2)	High	104	0.3
	Base	4	0.4
	Low	-52	0.3
Period 2 (Given Low Demand Period 2)	High	104	0.3
	Base	0	0.4
	Low	-43	0.3

Figure 4.6
Unidentified Block Loads and Generators

Unidentified Block Loads & Generators		Values (MW)	Probabilities
Period 3 (Given High Demand Period 3)	High	54.5	0.3
	Base	-14	0.4
	Low	-105.5	0.3
Period 3 (Given Base Demand Period 3)	High	61	0.3
	Base	-30	0.4
	Low	-101	0.3
Period 3 (Given Low Demand Period 3)	High	60	0.3
	Base	-1	0.4
	Low	-64.5	0.3

Unidentified Block Loads & Generators		Values (MW)	Probabilities
Period 4 (Given High Demand Period 4)	High	54.5	0.3
	Base	-14	0.4
	Low	-105.5	0.3
Period 4 (Given Base Demand Period 4)	High	61	0.3
	Base	-30	0.4
	Low	-101	0.3
Period 4 (Given Low Demand Period 4)	High	60	0.3
	Base	-1	0.4
	Low	-64.5	0.3

Unidentified Block Loads & Generators		Values (MW)	Probabilities
Period 5 (Given High Demand Period 5)	High	54.5	0.3
	Base	-14	0.4
	Low	-105.5	0.3
Period 5 (Given Base Demand Period 5)	High	61	0.3
	Base	-30	0.4
	Low	-101	0.3
Period 5 (Given Low Demand Period 5)	High	60	0.3
	Base	-1	0.4
	Low	-64.5	0.3

Unidentified Block Loads & Generators		Values (MW)	Probabilities
Period 6 (Given High Demand Period 6)	High	54.5	0.3
	Base	-14	0.4
	Low	-105.5	0.3
Period 6 (Given Base Demand Period 6)	High	61	0.3
	Base	-30	0.4
	Low	-101	0.3
Period 6 (Given Low Demand Period 6)	High	60	0.3
	Base	-1	0.4
	Low	-64.5	0.3

Figure 4.7
Muja to Bunbury Line Decommissioning

Muja Bunbury Line Decommissioning		MVA	Probabilities
Period 1	No	0	0.95
	Yes	-158	0.05

Muja Bunbury Line Decommissioning		MVA	Probabilities
Period 2 (Assuming "No" in Period 1)	No	0	0.75
	Yes	-158	0.25

Muja Bunbury Line Decommissioning		MVA	Probabilities
Period 3 (Assuming "No" in Period 2)	No	0	0.35
	Yes	-158	0.65

Muja Bunbury Line Decommissioning		MVA	Probabilities
Period 4 (Assuming "No" in Period 3)	No	0	0.2
	Yes	-158	0.8

Muja Bunbury Line Decommissioning		MVA	Probabilities
Period 5 (Assuming "No" in Period 4)	No	0	0.05
	Yes	-158	0.95

Muja Bunbury Line Decommissioning		MVA	Probabilities
Period 6 (Assuming "No" in Period 5)	No	0	0.05
	Yes	-158	0.95

4.2. Impact Model

Figure 4.8 shows a portion of the impact model used to calculate the impact of each path through the decision tree in the scenario model. The impact model calculates the NPC of each scenario in the Figure 4.1 decision tree for each year of the forecast horizon through 2040. The 2040 cut-off is arbitrary, but the thirty-year period is effective for capturing the effects of future decisions, uncertainties and costs on the current decision.

For convenience, only a portion of this horizon is shown in Figure 4.8. As noted earlier, there are potentially millions of such scenarios in the model. Figure 4.8 shows a snapshot of only one scenario. Importantly, we note that this impact model calculates the total NPC of an entire scenario of decisions and uncertainties. As a result, the analysis does not generate a separate “fixed” value and “flexibility” value for each alternative. Instead, it calculates an overall value that incorporates the value of flexibility; that is, the ability to adjust the investment over time.

The net present cost includes three quantities:

- Investment or capital cost needed for construction (‘Investment Cost’);
- Residual value or savings at the time of asset decommission (‘Residual Value’); and
- Reduced service cost if capacity is not fully adequate to serve demand (‘Reduced Service Cost’).

The first two quantities are the same as in Western Power’s traditional NPC analysis. However, we have calculated these quantities for far more scenarios than in Western Power’s earlier analysis.

The third factor is new, and was not included explicitly in Western Power’s NPC analysis. This factor is included to ensure that different alternatives are compared on a full-cost “apples to apples” basis across a wide range of scenarios. If an alternative provides reduced service (eg, higher unserved energy) in a particular scenario, an additional cost is added. This cost reflects the service obligations on Western Power and the service expectations of its customers. This cost is calculated using the measure and incentive rate as described in detail in the ‘Amended Proposed Revisions to the Access Arrangement for the South West Network Owned by Western Power’. As described on page 8, the relevant measure is System Minutes Interrupted (SMI), the unserved MW minutes divided by the system peak demand. As described on page 15, the relevant incentive/penalty is $25,000 per 0.1 change in the SMI capped at $2.6m per year.

Figure 4.8
Impact Model

	Start (2009)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
DEMAND												
Natural Load Growth	275	294.25	313.5	332.75	352	371.3	390.5	404.17	417.835	431.5025	445.17	458.8375
Previously Identified Block Loads Period 1						88	88	88	88	88	88	88
Previously Identified Block Loads Period 2											62	62
Newly Identified Block Loads&Generators Period 1						-32	-32	-32	-32	-32	-32	-32
Newly Identified Block Loads&Generators Period 2											4	4
Unidentified Block Loads&Generators Period 3												
Unidentified Block Loads&Generators Period 4												
Unidentified Block Loads&Generators Period 5												
Unidentified Block Loads&Generators Period 6												
Total Demand	275	294.25	313.5	332.75	352	427.3	446.5	460.17	473.835	487.5025	567.17	580.8375
CAPACITY												
Initial Capacity	550	550	550	550	550	550	550	550	550	550	550	550
Added Capacity Period 1				490	490	490	490	490	490	490	490	490
Added Capacity Period 2										0	0	0
Added Capacity Period 3												
Added Capacity Period 4												
Added Capacity Period 5												
Added Capacity Period 6												
Muja Bunbury Line Decommission						0	0	0	0	0	-158	-158
Capacity (MVA)	550	550	550	1040	1040	1040	1040	1040	1040	1040	882	882
Total Load Serving Capacity (MW)	522.5	522.5	522.5	988	988	988	988	988	988	988	837.9	837.9
Unserved Demand at Peak				0	0	0	0	0	0	0	0	0
Megawatt minutes of Unserved Energy				0	0	0	0	0	0	0	0	0
System Minutes Interrupted				0	0	0	0	0	0	0	0	0
Reduced Service Cost (Unconstrained)				0	0	0	0	0	0	0	0	0
COSTS												
Investment Cost	1.05	7.875	1.575					0	0	0		
Residual Value										0		
Reduced Service Costs				0	0	0	0	0	0	0	0	0
Total Costs	1.05	7.875	1.575	0	0	0	0	0	0	0	0	0
Discount Rate	DiscRate		8%									
Discounted Cost	1.05	7.293017225	1.3508089	0	0	0	0	0	0	0	0	0
Year	0	1	2	3	4	5	6	7	8	9	10	11
Total NPV	13.55194271											

Note: values shown in the above diagram are from one of the many scenarios modelled.

4.3. Conclusion

As described above, there are three key differences between NERA's Real Options Analysis and Western Power's traditional analysis. The NERA approach includes:

- A detailed comprehensive treatment of uncertainty and learning, including a full set of individual uncertainties, their dependence relationships, and their evolution over time
- An explicit treatment of flexibility, with investment strategies that include immediate, near-term and long-term decisions.
- A more complete treatment of cost impacts, by including potential reduced service costs associated with the different investment alternatives in particular scenarios.

5. Results

5.1. Introduction

Real Options Analysis generates a variety of results, some similar to those generated by traditional analysis and some quite different. In this application, we have generated the following key results:

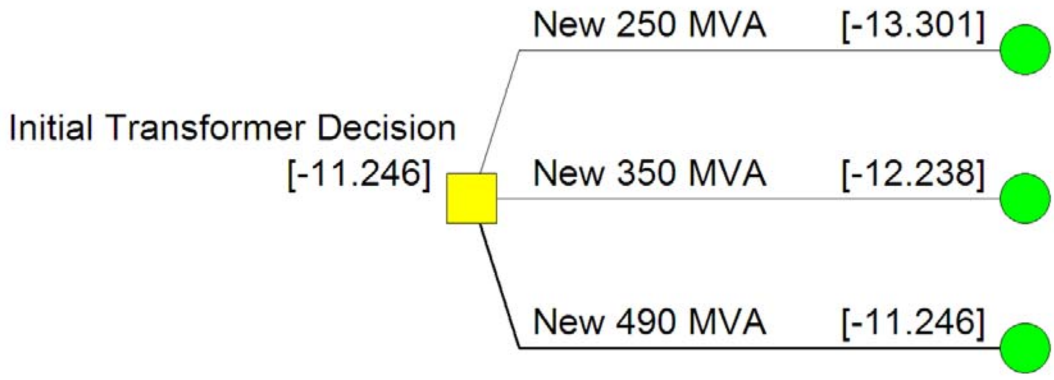
- Expected cost analysis - A comparison of the expected (probability-weighted) NPC of the decision alternatives, and identification of the expected NPC-minimizing current choice and future strategy
- Risk analysis - A comparison of the NPC risk of the decision alternatives
- Sensitivity analysis – An evaluation of the sensitivity of the results to key assumptions

These results are presented in more detail below. As noted earlier, these results are based on data provided by Western Power.

5.2. Expected Cost Analysis

Figure 5.1 compares the three current decision alternatives on the basis of expected NPC. The numbers in brackets on the right show the expected NPC in millions of dollars.[11] In applications such as this one, minimizing expected cost is the most widely-accepted decision criterion.

Figure 5.1
NPC of Initial Investment Alternatives ($ millions)



11 The different approach with ROA compared to the traditional NPC analysis undertaken by Western Power means that differences between the resulting NPCs are to be expected. As discussed in section 4, with ROA, costs incorporated include the costs of future investments as well as the current decision. It also includes the cost of potential reduced service levels associated with each alternative.

As the figure indicates, the costs associated with the 250 MVA decision is roughly $13.3m, the cost associated with the 350 MVA decision is roughly $12.2m and the cost associated with the 490 MVA decision is roughly $11.2m. As described in Section 4, these figures reflect the stream of costs over time associated with each of these initial decisions, including the subsequent investments undertaken. That stream of costs includes capital spent as well as residual value and reduced service costs (if any) over the period through 2040.

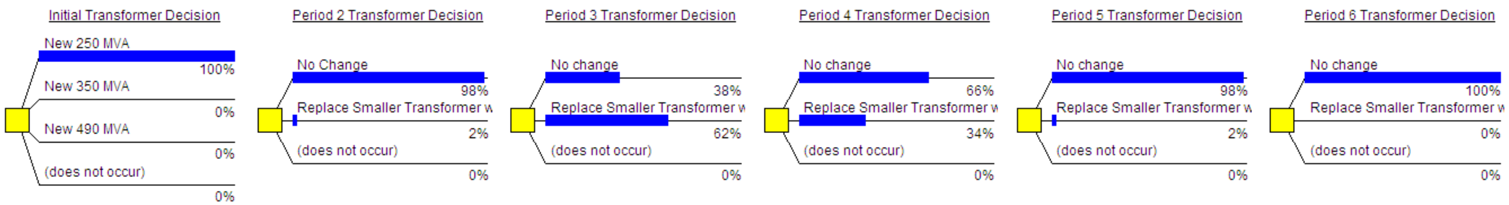
Based on the results reported above, the expected NPC-minimizing current investment choice is installation of a 490 MVA transformer. It is roughly $1m less costly than the 350 MVA alternative, and $2m less costly than the 250 MVA alternative.

As noted above, the cost associated with these three choices (250 MVA, 350 MVA and 490 MVA) reflects the projected cost of an entire strategy, not just the initial decision. The choices in this cost-minimizing strategy vary as circumstances unfold. Figure 5.2 summarizes the cost-minimizing investment strategy going forward associated with each of these three initial decisions.

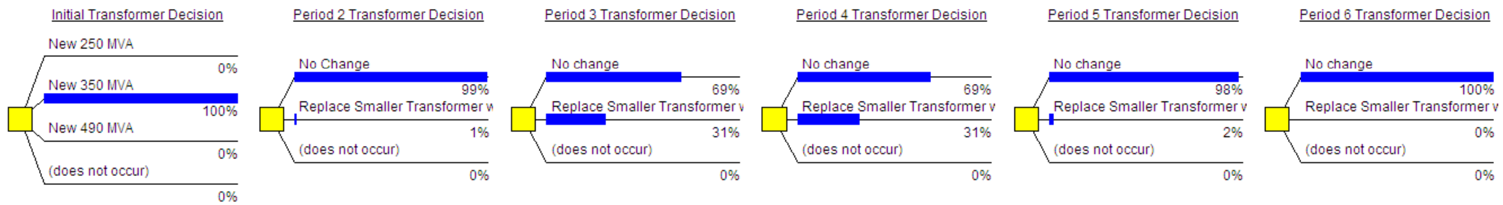
This figure provides substantial intuition behind the 490 MVA decision, and the flexibility it creates. If a 490 MVA is installed now, there is only a 2% chance that new capacity will be required through 2027. On the other hand, if a 250 MVA is installed now, there is a 64% that new capacity will be required before the end of 2027. In our model, this means replacement of the 225 MVA transformer. In a 350 MVA is installed now, the probability is 32%. The bottom line is that installation of the 490 MVA allows Western Power to avoid future replacements motivated by changes in network demand and supply conditions.

Figure 5.2
Expected-Cost Minimizing Investment Strategy

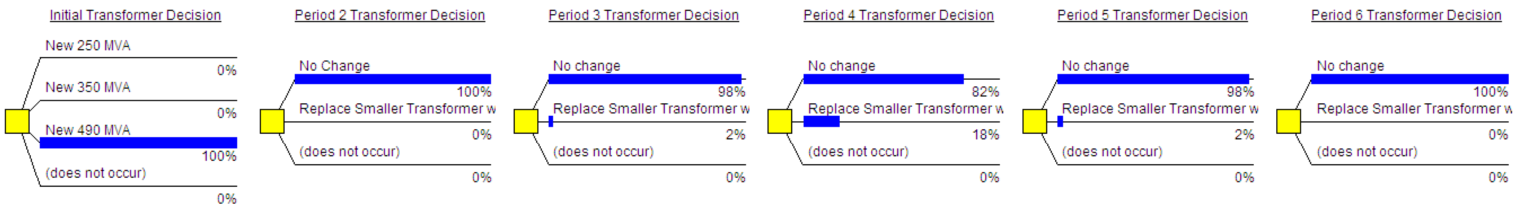
Initial Transformer: 250 MVA



Initial Transformer: 350 MVA

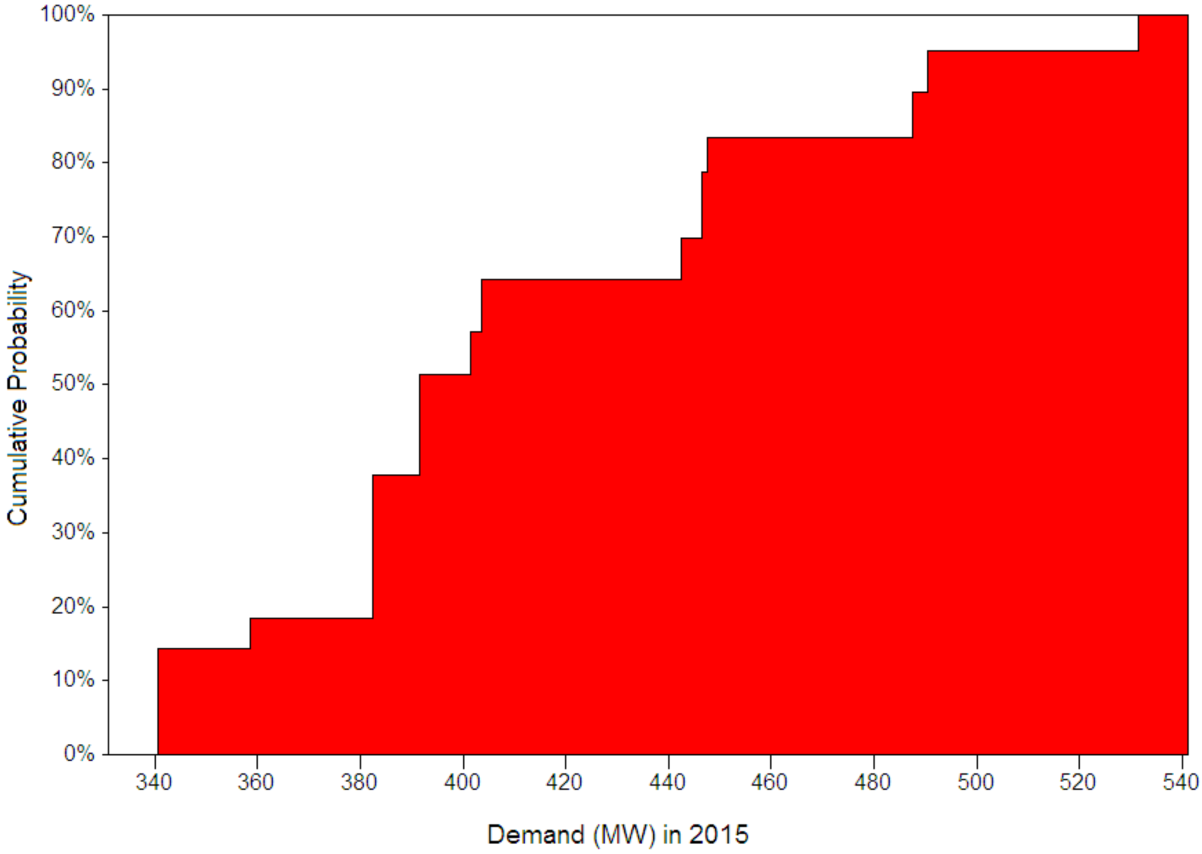


Initial Transformer: 490 MVA



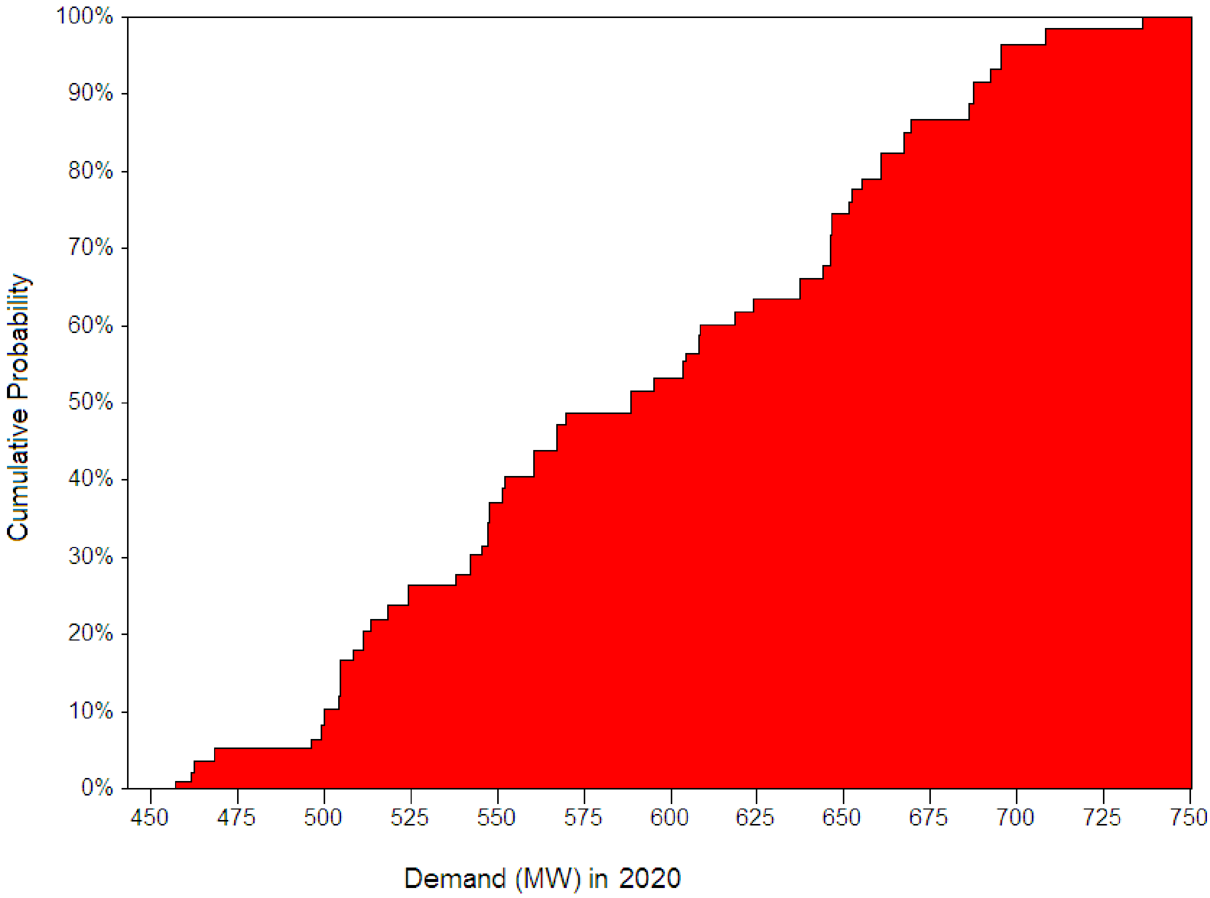
Further intuition behind this result can be gained by examining uncertainty regarding future demand and supply conditions, Figures 5.3 and 5.4 show the probability distribution for peak demand in 2015 and 2020. These figures exclude the potential impact of Muja-Bunbury decommissioning which is incorporated in the model as a decrease in effective capacity rather than a demand increase. If this potential decommissioning is included, the need for additional capacity becomes even higher.

Figure 5.3
Peak Demand at End of Current Period



Note: excludes possibility of Muja-Bunbury decommissioning which is treated as a capacity loss

Figure 5.4
Peak Demand at End of Period 2 (2020)



Note: excludes possibility of Muja-Bunbury decommissioning which is treated as a capacity loss

There are two points worth noting.

1. **Near-Term Reduced Service Cost**. If Western Power were to install the 250 MVA alternative, there is a good chance that it would be insufficient to meet demand only a few years after it begins operation. As Figure 5.3 indicates, the combination of natural load growth and block load additions means that there is roughly a 30% chance that peak demand will be above 450MW by the end of 2015. Under these circumstances, Western Power would either be faced with costly solutions or not meeting its performance standards. The penalty function serves as a proxy for these costs in the model.

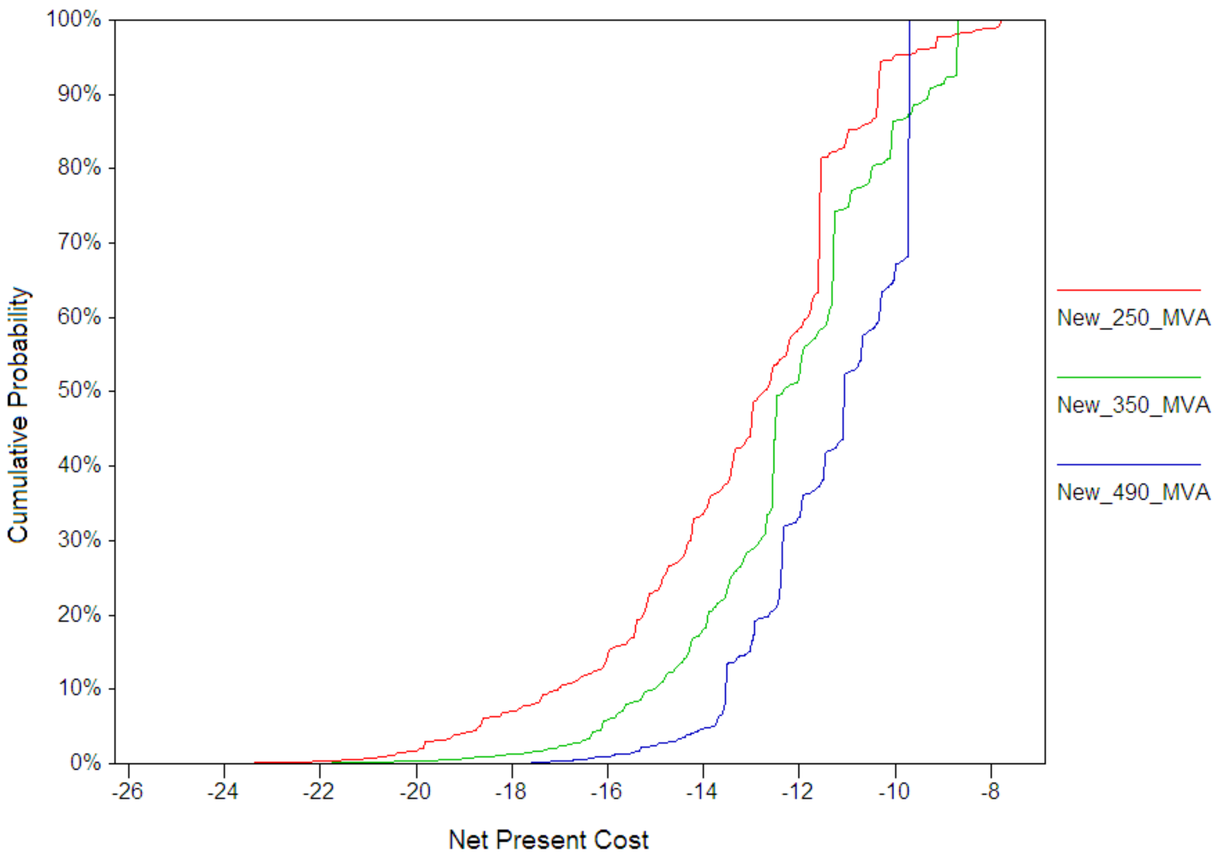
2. **Mid-Term Economies of Scale.** The 490 MVA transformer is 96% larger than the 250 MVA, but is only 26% more expensive. If there is a significant chance that "additional MVAs" will be needed fairly soon, it is more cost efficient for Western Power to install a larger MVA transformer. A smaller transformer basically uses up a valuable slot. As Figure 5.4 shows, there is roughly a 30% chance that peak demand could exceed 550MW by the end of 2020. Combined with the possibility of the Muja to Bunbury Harbour line

decommissioning, this indicates that there is indeed a significant chance that additional MVAs will be needed.

5.3. Risk Analysis

While expected cost is a well-accepted decision criterion, the range of possible costs – the cost risk – also deserves attention. Figure 5.5 illustrates the cost risk associated with the three Current Decision alternatives. As with expected costs, these figures capture the entire stream of future costs associated with each initial decision, including future capital costs, residual value and reduced service costs.

Figure 5.5
Cost Risk Associated with Current Decision Alternatives



The figure is in the form of a "cumulative" probability distribution where each point on a curve represents the probability that the cost associated with that alternative will be that level or more. This graph contains more information than the expected cost of each alternative; it shows the range or dispersion of costs.

Based on this graph, the 490 MVA alternative has a worst-case cost of roughly $18m and a best case cost of roughly $10m or a range of $8m. The 350 MVA alternative has a larger $22m worst case cost and a somewhat better best case cost of $9m for a range of $13m. Lastly, the 250 MVA alternative has a significantly larger $24m worst case cost and a best case cost of $8m or a range of $15m. In this form of analysis, risk is typically measured via the worst-case value or the range. Using these measures, the analysis indicates that the 490 MVA alternative is better not only from an expected-value basis, but from a risk point of view as well.

5.4. Sensitivity Analysis

Real Options Analysis, like any form of analysis, is based on a series of assumptions. Sensitivity analysis shows how the results vary as assumptions are varied. Such sensitivity analysis therefore helps in determining whether a recommended alternative is robust; that is, that the recommendation remains as assumptions are varied within substantial ranges. In our assessment, we conducted two major kinds of sensitivity analysis:

- First with respect to parameters, for assumptions such as the assumed reduced service cost.
- Second with respect to uncertainties, assumptions such as the likelihood of Muja-Bunbury line decommissioning.

5.4.1. Sensitivity to changes in input parameter values

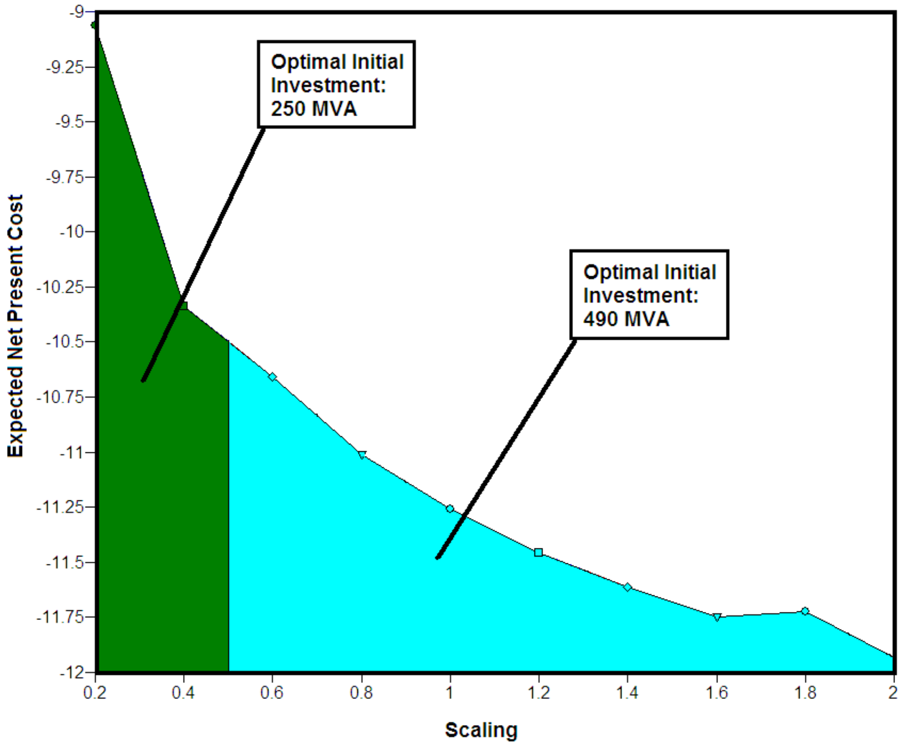
Figure 5.6 shows the sensitivity of the results on a key parameter - the reduced cost service cost – in the form of a rainbow diagram (named because of the colour changes). A multiplier on the cost is shown on the X axis. The current level (ie, the $25,000 per 0.1 SMI capped at $2.6m per year) is shown as 1.0. The cost of the expected NPC minimizing alternative is shown on the Y axis. Lastly, a change in the expected NPC minimizing choice is indicated with the two different-colour labelled regions.

As the figure indicates, the cost-minimizing alternative remains 490 MVA if the reduced service cost is increased above its current level to twice the level assumed in our base analysis. The 490 MVA also remains the cost-minimizing alternative if the reduced service cost is lowered, down to roughly 50% of its current value. Below this level, the cost minimizing alternative becomes 250 MVA. This is understandable since the main motivation for added capacity is to maintain service levels and prevent unserved energy.[12]

---

[12] Of course, if the reduced service cost is lowered to zero, the cost minimizing alternative becomes 250 MVA – the least expensive decision.

Figure 5.6
Sensitivity to Assumed Level of Reduced Service Cost



Similar sensitivities were conducted to other parameters including the discount rate and depreciation period. The results are similar with the cost minimizing alternative being largely insensitive to these parameters within wide ranges.

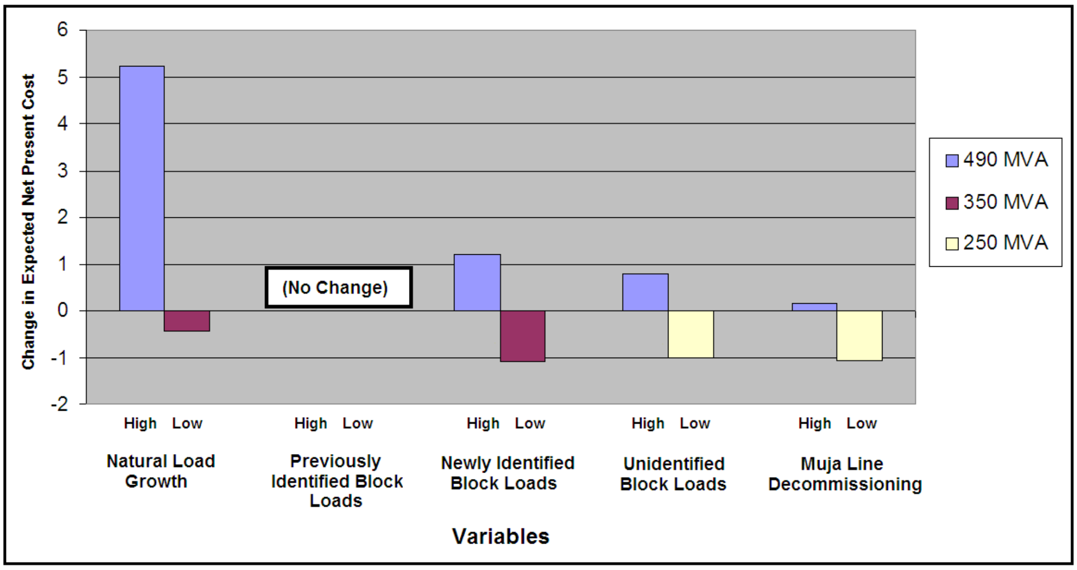
5.4.2. Sensitivities in relation to uncertainty assumptions

As discussed in 4.1.2, the model includes nineteen uncertainties organized into five categories.

We tested the sensitivity of the results to changes in the probabilities assumed in relation to each of these uncertainties. The results were found to be insensitive to changes in individual uncertainties, such as changing the likelihood of high natural load growth in Period 2 or the likelihood of decommissioning of the Muja to Bunbury line in Period 4.

To investigate sensitivity to even more substantive changes in assumptions, we conducted an analysis of extreme cases: where each of the five categories of uncertainty was varied from its low to its high level, rather than only the individual uncertainties in a given period within a category. For example, the sensitivity we tested in relation to the natural load growth rate ranged from low growth for the entire period from 2009 to 2040 to high growth for the entire period from 2009 to 2040. Figure 5.7 shows the sensitivity analysis in relation to these categories of uncertainties.

Figure 5.7
Sensitivity to Categories of Uncertainties



The figure shows both how the expected cost and cost-minimizing strategy changes as the category of uncertainties is varied. The height of each bar shows the expected cost; the change in colour indicates that the cost minimizing strategy has changed.

As the figure shows, the identification of the 490 MVA alternative as the cost minimising strategy is quite robust when the uncertainty assumptions increase. If the uncertainty assumptions decrease, the decision changes in four out of the five cases. Keep in mind that the situations shown above are extreme cases and are very unlikely – the indicated parameters would have to take on the lowest possible value in our distribution for all 30 years of the model.

5.5. Conclusion

The Real Options Analysis undertaken by NERA enables the quantification of the potential flexibility provided by alternative investment options at the Kemerton Terminal Station to address uncertainties in the demand and network supply conditions in the Bunbury region over time.

The key results from our model can be summarised as follows:

- The 490 MVA alternative has the lowest NPC once future uncertainties, future investment decisions and reduced service costs are explicitly incorporated in the assessment. The NPC of the 490 MVA option is $1m lower than that of the 350 MVA alternative and $2m lower than that of the 250 MVA alternative. The intuitive rationale for these results is that the 490 MVA alternative has the flexibility to enable Western Power to avoid costly future network investments as demand and supply conditions evolve.

- The 490 MVA alternative also has the lowest NPC risk. Its "worst case" cost of $18m is $4m better than the 350 MVA alternative and $6m better than the 250 MVA alternative. This result is again the result of the flexibility of the 490 MVA alternative to deal with more extreme demand and supply conditions.

We have undertaken a range of sensitivity tests to examine the robustness of these conclusions to changes in both the value of the underlying parameters used in the model and the assumptions made regarding future uncertainties. The results of these sensitivity tests indicate that the conclusions above are robust to changes in parameter assumptions over a sizable range, and to individual changes in the assumptions made about uncertainties in each period.

NERA Economic Consulting
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Tel: +61 2 8864 6500
Fax: +61 2 8864 6549
www.nera.com

NERA Australia Pty Ltd, ABN 34 092 959 665