Saha Energy International Ltd

Review of
Murraylink Transmission Company Pty Ltd's
Application of the Regulatory Test

As provided to the

Australian Competition and Consumer Commission

Final Report

February 2003

EXECUTIVE SUMMARY

Saha Energy International Ltd. (SEIL) has been engaged by the Australian Competition and Consumer Commission (Commission) to provide a review of Murraylink Transmission Company's (MTC) application of the regulatory test in regard to conversion of the network service to that of a prescribed service.

In this Review we have considered:

- the methodology, assumptions and findings of TransEnergie US Ltd (TEUS) in their assessment of the market benefits associated with Murraylink;
- the appropriateness of the alternative projects selected by Burns and Roe Worley (BRW), and the costs associated with those alternatives; and
- the appropriateness of the opening asset valuation, in line with the regulatory test.

Within the scope of this Review, we have not performed audits of the underlying models utilised in support of the Application, and have not provided a view in regard to the internal integrity of those models or the raw data inputs.

Our primary data source has been the Application by MTC and the supporting material provided in the Appendices, with additional information provided to us during the course of this review by the Applicant. This information has been considered against a number of documents and data sources within the public domain.

A summary of our conclusions and recommendations follows below. A more complete statement of these conclusions and recommendations are presented in the body of our Review.

ASSESSMENT OF MARKET BENEFITS

The methodology employed by TEUS in estimation of market benefits appears to us as broadly consistent with guidelines set out under the regulatory test, and in application of the test in recent studies referenced by TEUS and reviewed by us.

- Most of the primary components comprising market benefits are consistent with those identified in comparable analysis undertaken for the SNI and SNOVIC interconnection.
- While there are certain technical aspects underlying the methodology chosen by TEUS to estimate market benefits which do diverge from comparable studies, we do not find such divergence as clearly

unreasonable. In most cases where there is a divergence in methodology, the treatment has been reasonably transparent, although in certain cases more detailed assessment may be warranted given the technical complexity of the matters considered here. The way in which TEUS has modelled merchant generation entry (in the "with" and "without" Murraylink scenarios) is a case in point, where the conceptual framework for analysis appears to us as appropriate, but further review of the detailed modelling techniques, assumptions and outcomes is warranted, as the value of generation deferral is a key component of the overall estimate of market benefits.

- We are generally comfortable with the choice of modelling tools employed by TEUS in their assessment of market benefits in terms of the practical alternatives available, but note that the findings provided are sensitive to a number of features underlying those models, and that they are subject to error in estimation. This is a matter common to similar market benefit studies carried out in the estimation of market benefits, where proxies are defined for unobservable variables, and simulation models are employed to form forward projections of stochastic variables.

- In general, we find that many of the key assumptions employed by TEUS are broadly consistent with those of other recent studies which have estimated market benefits under the regulatory test. While there may be room for professional debate on the specific setting of certain assumptions, we do not generally find the TEUS assumptions to be clearly in-appropriate.

However, one must recognize that there are a number of key assumptions which will have a direct and material impact on the estimated value of market benefits. We have discussed in detail some of these factors, and highlighted a set of those under which the estimate of market benefits is highly sensitive.

This matter becomes particularly significant within the context of the MTC Application, where the estimated value of market benefits provides the basis for the setting of the maximum allowable revenue which MTP would be allowed to recover from transmission customers.

APPROPRIATENESS OF ALTERNATIVE PROJECTS

Burns and Roe Worley Pty Ltd (BRW) have provided four alternatives which are intended to provide the same level of services as Murraylink, as well as giving brief consideration to a generation option and demand side management. Alternatives 1, 2 and 3 provided by BRW are broadly consistent with an appropriate choice of alternatives for determining the

DORC of Murraylink in that they provide similar technical services, but do not provide higher level of services[1].

On the other hand, the technical services provided by Alternative 4 appear to us as significantly different to those provided by Murraylink. The market benefits are also significantly different in that Alternative 4 provides no benefit to the Snowy/NSW or Snowy/Victoria interconnections, and does not provide a direct linkage between the South Australian and NSW market regions. Therefore, Alternative 4 does not provide a sufficiently similar level of service as Murraylink to be considered an alternative to Murraylink for purposes of determining a DORC for Murraylink. We also agree with BRW that the generation option considered and Demand Side Management do not provide a similar level of service within the framework considered here.

- The significant proportion of costs made up by the underground cable costs highlights the dependence of the base cost estimates on the recommendations on the extent to which undergrounding is considered necessary. We believe that stronger justification should be provided for both the need for, and cost of, underground cables for the alternative projects. On basis of the information provided to date, we do not consider that a sufficiently robust case has been made for the extent of undergrounding for it to be used to determine a DORC value.

- BRW has added an allowance for contingency which has been added to base cost estimates. A contingency was calculated for each of the alternative projects using @Risk in Excel, a spreadsheet model utilised to assess the probability of the base cost estimate being too low or too high. BRW recommends that the P75 cost be used as the replacement cost of the alternative projects. We consider that the P75 cost estimate is an overly conservative basis for valuation. While the general approach taken by BRW has merit, we believe that the P50 cost is more in keeping with the ORC methodology which is aimed at setting a typical cost for particular categories of assets. We believe that further consideration be given to the specification of the contingency framework especially if the DORC methodology is to be more widely applied in the NEM.

APPROPRIATENESS OF ASSET VALUATION

We agree with the conceptual approach to asset valuation taken by MTC in regard to its use within the regulatory test. We find precedents which would support the use of an *economic value* for the asset base in terms of both the regulatory test; and for the purpose of revenue recovery (as incorporated into the regulatory asset base) where we interpret the MTC approach to asset valuation as an economic value approach - consistent with ODV techniques.

[1] The latter condition is usually applied to ensure that asset values are not inflated by choosing modern equivalent assets that provide a higher level of service (at a higher cost).

As an unobservable variable, MTC's regulated asset value (as defined by the estimated value of market benefits) is subject to estimation error. As a ceiling in regard to the regulatory test, it may be that the outcome of the test as put forward by MTC is robust to such error – particularly keeping in mind that much of the costs of Murraylink are sunk.

However, as a key variable in the setting of maximum allowable revenue, estimation error may be material to the outcome.

- Given the potential for error in the estimation of net market benefits, the sensitivity of this variable to key assumptions, and the impact that this error could have on the setting of the maximum allowable revenue, we think it prudent to undertake a more comprehensive assessment of the setting of the regulatory asset value, with attention given to the summary measures used to "build up" the value of market benefits - thus the regulatory asset value.

- In doing so, it would be useful to refine the framework for estimation of market benefits, including the setting of key parameters underlying the estimation of market benefits.

- We see the ODV approach as offering a robust framework in which to place the setting of the opening asset base – which we view as amenable to the approach proposed by MTC.

SUMMARY RECOMMENDATIONS

1) Given the importance of the findings provided by TEUS (that is, the estimated value of market benefits) and their sensitivity and propensity for error, we recommend that further assessment be carried out.[2] This would include review of areas such as:

    - the modelling procedures employed by TEUS;
    - raw data inputs to the models;
    - key data outputs;
    - calculations of final summary measures used to "build up" the value of market benefits; and
    - "stress test" of the model outputs to better determine the sensitivity of results to key inputs.

2) Further review of the modelling technique applied in estimation of merchant generation entry should be undertaken to more clearly assess its robustness to a well defined set of key assumptions. The aim here is to obtain a robust estimate of the value of generation deferrals.

[2] This recommendation is made without prejudice to the modelling carried out in support of this Application.

3) Further consideration should be given to the way in which "contingency costs" have been computed for the set of alternative projects, and the extent to which undergrounding costs are appropriately considered.

4) We recommend that sensitivity analysis be carried out to test the robustness of the estimated regulatory asset value to threshold parameters (such as full life-cycle O&M costs of Murraylink) as set out in the MTC approach to the regulatory test.

Addendum

The Commission, in parallel to our Review, has engaged PB Associates to provide a review of the power transfer capability provided by Murraylink. PB Associates have recommended that further dynamic studies be undertaken in regard to certain assumed power transfer limits[3]. Depending on the findings of those studies, additional modelling may be required in re-estimation of the value of market benefits.

[3] PB Associates Transfer Capability Review of the Murraylink Application to ACCC. January 2003.(pages 35-36)

1 INTRODUCTION AND CONSULTANCY TERMS OF REFERENCE

1.1 Background to this Review

Murraylink Transmission Company Pty Ltd (MTC), on behalf of Murraylink Transmission Partnership (MTP), has applied to the Australian Competition and Consumer Commission (Commission) seeking a determination that[4]:

> *…the network service provided by Murraylink be classified as a prescribed service for the purposes of the National Electricity Code (Code); and*
>
> *for the provision of this prescribed service, MTP be eligible to receive the maximum allowable revenue from transmission customers (through a Coordinating NSP) for a regulatory control period from the date of effect of the Commission's final decision on the Application to 31 December 2012.*

To assist in forming its determination, the Commission has undertaken a review of MTC's application of the "regulatory test" in assessing whether Murraylink should be classified as a prescribed service under the Code.

1.2 Consultancy Terms of Reference

Saha Energy International Ltd. (SEIL) has been engaged by the Commission to provide a review of certain elements of MTC's application. More specifically, the Consultancy Terms of Reference are as follows.

> *The consultant is to undertake a review which analyses and comments on the assumptions, methodology and findings of TransEnergie US Ltd's (TEUS) assessment of the market benefits associated with Murraylink (Appendix D of MTC's application).*
>
> *The consultant is also required to assess the review undertaken by Charles River Associates Asia Pacific (Appendix E of MTC's application).*
>
> *The consultant must assess the appropriateness of the alternative projects selected and assessed by Burns and Roe Worley (Appendix F of MTC's application). In particular, the consultant should address the following questions:*
>
> - *Were the alternative projects identified by MTC appropriate?*

[4] Murraylink Transmission Company Pty Ltd: Application for the Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12. 18 October 2002.

> - *Were their costs and market benefits calculated appropriately?*
> - *Are there other alternatives that should have been considered? and*
> - *If so, what are the costs and benefits of these alternatives?*
>
> *The Consultant is also required to comment on the appropriateness of the opening asset valuation submitted by MTC, in line with the results obtained under the regulatory test; and the suitability of the standard useful lives adopted by MTC for depreciation purposes.*

1.3 Our Approach to this Review

Given the Commission's requirement that our Review be completed within a relatively short period of time, SEIL has undertaken a high level review of the assumptions, methodologies and findings covered under this consultancy.

Where possible:

- *assumptions* regarding key inputs have been checked for reasonableness against published data;
- *methodology* has been considered against related applications, and what could reasonably be expected in terms of best practice as currently applied to the NEM; and
- *findings* have been checked in terms of robustness and logical consistency – utilising where available relevant benchmarks as a point of reference.

We have not performed computational audits of the underlying models utilised by the various consultants, and have not provided a view in regard to the internal integrity of those models. Neither have we undertaken a comprehensive "bottom up" audit of each and every input to the models to check for accuracy in the data and application of stated assumptions.

To satisfy the requirements of the Commission, our approach has been to look at a sub-set of primary inputs which might have the most significant effect on key outputs, and then to cross-check those outputs against each other to give an indication of the internal consistency of the underlying methodology and computations. As noted above, certain outputs have then been compared to external benchmarks as an overall point of reference.

Our primary data source has been the Application by MTC and the supporting material provided in the Appendices, with some additional information provided to us during the course of this review by the

Applicant. As mentioned above, this information has been considered against a number of documents and data sources within the public domain which have been listed as footnotes within this Review.

2 REVIEW OF MARKET BENEFITS AS ASSESSED BY TRANSENERGIE US LTD

TransEnergie US Ltd (TEUS) has undertaken an assessment of the market benefits stemming from the network service provided by Murraylink as part of their Application to the Commission for conversion to regulated status[5].

In consideration of material provided in support of the Application, the Commission has engaged SEIL to:

> *…undertake a review which analyses and comments on the assumptions, methodology and findings of TransEnergie US Ltd's assessment of the market benefits associated with Murraylink (Appendix C of MTC's application).*

In undertaking this part of our Review, we have considered the assumptions, methodology and findings of the TEUS assessment primarily by comparison against similar studies, augmented by our understanding of matters relevant to the points being made. We have not had access to either the models used for the assessment of market benefits, or the data underlying the modelling procedures. We have also not undertaken an audit of the accuracy of the TEUS calculations, or the integrity of the models employed for their analysis.

We have been provided with additional information from the Applicant, primarily in regard to certain additional sensitivity checks, and clarifications on technical matters. We have also benefited from an information briefing provided to the Commission and consultants on the calculation of market benefits.

This section (2) of our Review sets out our analysis of the TEUS assessment of the value of market benefits stemming from the network services provided by Murraylink. In doing so, we first provide a brief definition of market benefits as placed within the regulatory test. We then provide an overview of the methodology used by TEUS in assessing the value of market benefits stemming from the network service. Primary assumptions underlying the TEUS assessment are then evaluated. Finally, we consider the main findings provided by TEUS, and sensitivity of those findings to key assumptions underlying the assessed value of the network service.

2.1 Market Benefits and the Regulatory Test

The provisions under which a Market Network Service Provider can convert to regulated status are rather broad, and allow for discretion on the part of the Regulator (the Commission) in determination of the matter. In light of this, MTC has proposed that the "Regulatory Test for New

[5] Appendix D: Report on the Estimation of Murraylink Market Benefits – TransEnergie US Ltd.

Interconnectors and Network Augmentations"[6] be utilised as the basis for evaluation of its Application.[7]

The Commission has promulgated the regulatory test in accordance with clause 5.6.5(q)(1) of the Code.[8] The regulatory test defines market benefit as:

> *the total net benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios.*

Unless the project under evaluation is an intra-regional transmission line that is proposed for the purpose of meeting certain objectively measurable service standards, then the regulatory test requires that the project must be shown to maximise the net present value of the market benefit with regard to a number of alternative projects, timings and market development scenarios.

As part of a commentary on the definition of market benefits[9], the Commission has noted that it has relied on the principles of cost/benefit analysis in developing the test, with two implications for analysis:

> *First, cost/benefit analysis does not rely on market prices where there is good reason to believe these prices are distorted by a market failure (eg use of market power). For this reason, the Commission has based the regulatory test on the notion of a net public benefit derived from a comparison of the economic costs associated with each alternative. The Commission has moved away from a test based on price outcomes which may not reflect competitive market behaviour but may include distortions due to behaviour reflecting the use of market power.*
>
> *Second, the costs and benefits included in the analysis are assessed from an economy wide perspective, and no account is taken of sectional impacts. The latter factor supports the notion of moving away from a customer benefit criterion which seemingly emphasises the benefits of one group of users over another. It would also remove wealth transfers from the analysis as the focus of the investment analysis is on economic costs and benefits and not on their distribution.*

As a practical outcome of the move away from a test based on price, evaluations performed to date can be interpreted as a cost minimisation

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[6] ACCC, Regulatory Test for New Interconnectors and Network Augmentations. 15 December, 1999

[7] Also noting that in its 21 September 2001 Determination on network pricing and MNSP code changes, the Commission proposed a conversion process which "delivers outcomes consistent with the intent of the regulatory test" (page 138).

[8] Noting that the test was not explicitly designed for use in regard to conversion to regulated status

[9] ACCC, Regulatory Test for New Interconnectors and Network Augmentations. 15 December, 1999, page 4

test. Project proponents have typically endeavoured to demonstrate that, when compared to some baseline project, no alternative project or timing would provide a larger reduction in the net present cost of the "market" under most credible scenarios or sensitivity tests. Thus, *cost savings* are often a key metric in defining market benefits.

As a final point to be made in this brief summary section, the role of market benefits within the regulatory test is to serve as a benchmark against which the costs of proposed projects are to be assessed. Because of this, the test is not heavily prescriptive, providing only general guidance on the assumptions to be used. The structure of the test essentially requires that a range of scenarios and variants and a number of alternative projects be evaluated in order to confirm the robustness with which the proposed project maximises market benefits.

2.2 Overview of TEUS' Methodology for Estimation of Market Benefits

2.2.1 The components of market benefits

TEUS specifies the gross market benefit of the Murraylink interconnector as consisting of four main components:

1. reduced energy costs – including fuel savings, reduced O&M costs, and reduced voluntary load curtailments;
2. deferred market entry of new merchant generation – including capital deferral and avoided O&M;
3. reliability benefits – including reduced unserved energy (USE); and
4. deferred Riverland augmentation - including capital deferral and avoided O&M of transmission upgrades to the Riverland region.

We briefly outline the broad technique employed in estimation of these four components of gross market benefits, and compare that at a high level to similar studies. We also consider the modelling platforms used to apply the methodology proposed by TEUS.

A more detailed discussion regarding the assumptions used in application of this methodology follows in subsequent sections of this Review.

2.2.2 Reduced energy costs

TEUS proposes that the addition of a 220 MW interconnector between South Australia and Victoria increases the opportunity to displace more expensive generation in one region with less expensive generation in another, thereby reducing system-wide costs.

TEUS cites the methodology and assumptions used by the IRPC on the Stage 1 Report: Proposed SNI Interconnector, in which a "with and without" analysis was undertaken which attempts to measure the change in system-wide fuel and O&M costs attributed to the interconnector.

Reductions in energy costs are modelled by simulating unit specific (market based, assuming SRMC bids) dispatch profiles across the NEM over the 10-year horizon for the "with" and "without" cases. System-wide fuel costs associated with each scenario are computed, with the savings attributed to Murraylink as a market benefit. TEUS has also, (primarily for the purpose of computation) placed the cost of activating interruptible loads as an energy cost saving by "dispatching" involuntary interruptible load as high cost generation.

2.2.3 Deferred market entry

The additional availability of power to South Australia provided by Murraylink is claimed to lead to both temporary deferral of new merchant generation capacity, in which case there are timing benefits of deferred capital expenditure, and a permanent deferral of some new generation, due to improved utilisation of generation capacity, e.g. through reserves sharing. These deferrals of capital and fixed operating expenditure represent a market benefit attributable to Murraylink.

Market dynamics are addressed by TEUS through a market entry "equilibrium balancing" process, which is calculated for the "with" and "without" Murraylink cases. In forming the long run equilibrium for each case, this balancing process has been employed which is (as we understand it) essentially an algorithm which calculates financial flows which could be captured by a generation unit, and compares that to the cash flow required in each year to support commercially driven entry in that year of one or more generators that are selected from a range of hypothetical plant types. This forms an iterative "loop" whereby the market model is then run again for successive years with updated generation assumptions.

The generation plant types are:

- open cycle gas turbine;
- combined cycle gas turbine;
- black coal; and
- brown coal.

The generic cost for each generator type is that provided in the IRPC Stage 1 report on SNI.

The outcome of this balancing process factors indirectly into the value of reduced energy costs described above, and directly into the deferred market generation benefits.

The modelling methodology described by TEUS to estimate both energy savings and deferred market entry sets out the following steps:

- development of a long run market equilibrium with Murraylink in service based upon market entry of merchant generation in response to regional prices resulting from short run marginal cost (SRMC) bidding behaviour for each generator;

- development of a similar long run market equilibrium with Murray link not in service;

- quantification of the market benefits of deferral of market entry generation resulting from the presence of Murraylink;

- quantification of the difference in variable generation costs (fuel plus variable O&M) on a monthly basis between the "with" and "without" Murraylink simulations; and

- quantification of the difference in voluntary load reduction (also referred to as interruptible load or dispatchable demand) on a monthly basis between the "with" and "without" Murraylink simulations.

2.2.4 Reliability benefits

TEUS proposes that the increase in transfer capability between regions, provided for by interconnectors such as Murraylink, makes reserve sharing possible and thus increase system reliability for a given investment in generating plant.

Reliability benefits have been estimated by TEUS as the change in USE between the case which includes Murraylink and that which does not. The annual reliability benefit is calculated as the change in estimated USE multiplied by VoLL (which has been set at $10,000[10]).

2.2.5 Deferred Riverland augmentation

As set out by the South Australian Electricity Supply Industry Planning Council (ESIPC), reinforcements to the South Australian grid will be required if the Riverland system is to meet relevant operational performance standards.

TEUS propose that deferral benefit will accrue to Murraylink equal to the present value of deferring Riverland construction costs as specified in **its** modelling exercise. At the broad conceptual level, this capital deferral is similar to that of generation deferral, although the underlying calculation is treated differently. In the case of the Riverland deferral, the matter is treated as an exogenous factor, driven primarily from analysis carried out

[10] As we will set out in later section on assumptions, VoLL, like other variables, has been set in real terms, leading in this case to a nominal value of $10,000 indexed up for inflation over the projected time horizon.

by the ESIPC, and adjusted by TEUS for changing market factors. As an exogenous input, we will discuss the underlying assumptions which are critical to this matter to the next section of our Review.

2.2.6 Summary comparison of market benefit components

In the table below, we have briefly summarised the primary components of market benefits as assessed by TEUS, and listed the treatment of these in similar studies.

Table 2.1 Identified Market Benefits of Transmission Interconnector Assessment

	Murraylink[11] interconnector	**SNI interconnector[12]**	**SNOVIC interconnector[13]**
Market Benefit	**TEUS**	**ROAM**	**ROAM**
Reduction in energy costs	• Fuel savings • Reduced other variable O&M expenses • Reduced voluntary load curtailments	Equivalent treatment	Equivalent treatment
Capacity deferral – CapEx & O&M	• Improved sharing of reserve and energy production capacity • Lower long run capacity requirements • Reduced O&M on new generation	Equivalent treatment	Equivalent treatment
Reliability benefit	• Improved ability to handle unforeseen forced outages and unusually high demand • Reduced volume of unserved energy	Equivalent treatment	Equivalent treatment
Deferral of Riverland transmission upgrade - Capital & O&M	• Deferred transmission augmentation in the Riverland area	Equivalent treatment	Equivalent treatment

2.2.7 Modelling tools employed by TEUS

To estimate the market benefits of the Murraylink interconnector, TEUS has used a linear programming dispatch and pricing model with some simulation capability (PROSYM); and a Monte Carlo simulation model (MARS).

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[11] Assessment of Murraylink Market Benefits, Comments on TransEnergie US Study, October 2002

[12] NEM forecasting – Economic Evaluation of the Proposed SNI Interconnector NEM00004 (updated final report to NEMMCO and the IPRC), ROAM Consulting, 26 October 2001, p5

[13] NEM forecasting - Economic Evaluation of the Proposed SNOVIC Project NEM00005 (final report to NEMMCO and the IPRC), ROAM Consulting, 29 October 2001

PROSYM calculates generation dispatch on an hourly basis, and the values that it determines are the average results of eight simulations[14]. PROSYM is unable to take into account transmission outages, whether planned or unplanned.[15] It cannot handle more than one interconnector between two regions. PROSYM distinguishes between the crucial Heywood and Murraylink interconnectors, by treating Murraylink as two interconnectors connected in series and joined in an artificial region of the NEM. This artificial region contains no load and no generation. PROSYM is also unable to dynamically represent the flow constraints that occur on each interconnector. PROSYM requires as an input the specific hours of the day, month and year the interconnector will be particularly constrained.

MARS is able to take into account generator operations, generator maintenance, generator unplanned (forced) outages, and load uncertainty. As a stochastic simulation model, MARS has been used primarily in regard to estimation of reliability parameters such as USE.

TEUS has evaluated the market benefits over a planning horizon that extends from 1 May 2003 through to 30 September 2042. Values for the first ten years of the analysis were computed using the PROSYM and MARS models. Year 10 values have simply been replicated for years eleven through forty of the planning horizon under the assumption of convergence to long run equilibrium by year 10.[16]

While a detailed review and audit of the modelling tools utilised for the assessment of market benefits is beyond our scope of work, we do wish to make the following point. The modelling tools used here are by necessity complex. This is in our view typical to the nature of the analysis required, and is consistent with what we see as best practice both within Australia and globally.

However, it must also be noted that the *modelling procedures* will in many cases have a direct impact on key findings. This is in addition to what typically are considered as *assumptions*, which we review in the next section.

This is rather different from the case of broadly related regulatory matters, such as the setting of maximum allowable revenue (the example used simply for illustration of our point). In this case, modelling tools have become standardised, allowing for replication of results for a given set of assumptions. This is not necessarily (or likely) the case for the assessment of market benefits. Arcane features of the models utilised will influence key findings, and are often difficult to track even where best endeavours are made to provide transparency to the modelling process.

[14] MTC response to question 1.3 of SEIL information request, seil_1-3.doc, 3 December 2002.

[15] Estimation of Murraylink Market Benefits, TransÉnergie US Ltd, undated, in Appendix D of the Murraylink application, pp 10 & 14.

[16] The sensitivity of estimated market benefits is considered in a following section.

2.2.8 Conclusions on TEUS methodology

The methodology in which TEUS has estimated market benefits appears to us as broadly consistent with guidelines as set out under the regulatory test, and in application of the test in recent studies referenced by TEUS and reviewed by us.

Most of the primary *components* comprising market benefits are consistent with those identified in comparable analysis undertaken for the SNI and SNOVIC interconnection.

While there are a number of technical aspects underlying the methodology chosen by TEUS to estimate market benefits which do diverge from comparable studies, we do not find such divergence as clearly unreasonable. In most cases where there is a divergence in methodology, the treatment has been reasonably transparent, although in certain cases more detailed assessment may be warranted given the technical complexity of the matters considered here, again noting that we have not undertaken an audit of the models employed for this assessment of market benefits.

We are generally comfortable with the choice of modelling tools employed by TEUS in their assessment of market benefits *in terms of the practical alternatives available,* but note that the findings provided are sensitive to a number of features underlying those models, and that they are subject to error in estimation. This is, of course, the case with other commonly utilised modelling tools as well.

2.3 Technical Review of Primary Assumptions

There are a number of key assumptions which must be provided as inputs to the simulation models in order to estimate the value of market benefits. At this relatively early stage of development of the regulatory test, only broad guidelines exist in which to make such assumptions.

In regard to the guidance that does exist under the regulatory test, section (1) (b) of the "Notes" on the methodology to be used state that the reasonable forecasts should be used in respect to:

i. *electricity demand (modified where appropriate to take into account demand side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);*

ii. *the value of energy to electricity consumers as reflected in the level of VoLL;*

iii. *the efficient operating costs of competitively supplying energy to meet forecast demand from existing, committed and modelled projects including demand side and generation projects;*

iv. *the capital costs of committed, anticipated and modelled projects including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;*

v. *the cost of providing sufficient ancillary services to meet the forecast demand; and*

vi. *the capital and operating costs of other regulated network market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.*

Key technical assumptions underlying the TEUS assessment of market benefits are considered below.

2.3.1 Demand sets

TEUS has modelled three demand scenarios based on high, mid, and low economic growth. The demand sets have been prepared from load traces used in the SNI study. In the analysis underlying the SNI study, half hourly load profiles for each of the five regions of the NEM were developed for 10%, 50% and 90% probability of exceedance (PoE), corresponding respectively to, extreme weather (exceeded one year in ten), average weather (exceeded one year in two) and mild weather (exceeded nine years in ten).[17] The SNI report states that these demand assumptions are consistent with the forecasts published in the NEMMCO 2001 Statement of Opportunities and its Addendum.

For the SNI study, historical annual load traces were selected that had typical shapes for years with maximum temperatures that corresponded to the 10, 50 and 90 % PoE. For the SNI project dispatch simulation of future years, the historic load traces were scaled to match forecast demand and energy requirements while preserving the general shape of the trace.

The historical annual load traces selected in the SNI study for the New South Wales, Victorian and South Australian regions with shapes for years with maximum temperatures that correspond to the 10%, 50% and 90% PoE are 1996/97, 1994/95 and 1995/96 respectively. For Queensland, Powerlink selected 1997/98 for all years because previous years included a substantially lower level of large industrial loads with a high utilisation factor.[18] For the Queensland region, two base load profiles were separately included: the Boyne smelter (modelled as 800MW base-load); and the Korea Zinc smelter 1st stage (modelled as 90MW base-load).[19] As with the SNI study, no load has been modelled in Snowy.[20]

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17 SNI Stage 2 Report, IRPC, Version 07, 26 October 2001, p7.

18 SNI Stage 1 Report, IRPC, Version 014, 26 October 2001, p25, p48. pp78–87.

19 Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p21.

20 Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p20.

The demand sets used in PROSYM are IRPC's 50% PoE demand traces, converted (through averaging) from a half-hourly to an hourly format.

The hourly demands used in MARS were prepared for each of eight sub-regions. To model the temperature-weighted uncertainties, a table of demand multipliers and their associated probability of occurrence was also prepared.

To prepare the demand sets, the half-hourly regional load traces for Queensland, New South Wales, Victoria, and South Australia that were used in the SNI study were converted into hourly traces. No demand sets were prepared for Snowy since it is a net generator in all periods.

The New South Wales, Victoria and South Australia regional traces were then apportioned into sub-regional load traces by prorating them with sub-regional off-take allocations derived from data based on 2003/4 summer peak demand conditions. These allocation factors are shown in the table below.

Table 2.2 Load Allocation Factors

Region	Subregions	Demand allocation
NSW	NSW_N	95.6%
	Wagga	3.9%
	Buronga	0.5%
Victoria	Vic_S	96.9%
	Redcliffs	3.1%
SA	SA_W	97.2%
	Riverland	2.8%

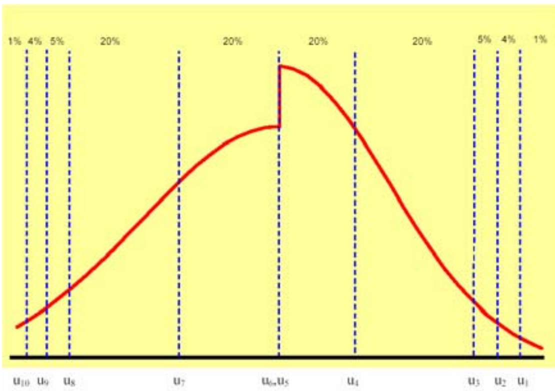
For each of the four regions, two normal distributions were defined. The first distribution has a mean of 1 and a variance such that the 90th percentile of the distribution results in a value equal to the ten-year average of the ratios between the M90 and the M50 datasets for that region. As an example, the average M90/M50 ratio for South Australia is 0.958.

The second distribution has the same mean and a variance such that the 10th percentile of the distribution results in a value equal to the ten year average of the ratios between the M10 and the M50 datasets for that region. As an example, the average M10/M50 ratio for South Australia is 1.076.

The lower half of the first distribution and the upper half of the second distribution are then pieced together to create two joined half-normal distributions. Abscissas were defined in each half-normal distribution such that they segmented the total distribution into 10 bins, the respective areas of the bins being 1%, 4%, 5%, 20%, 20%, 20%, 20%, 5%, 4%, and 1% of the total area under the distribution.

For example, for the high-side distribution a value u_1 was found such that $\Pr(x > u_1) = 1\%$. Similarly, a value u_2 was found such that $\Pr(u_2 > x > u_1) = 4\%$. The distribution and the ten bins are shown in the diagram below.

Figure 2.1 Conceptual illustration of how the probability bins are developed from the paired normal distributions

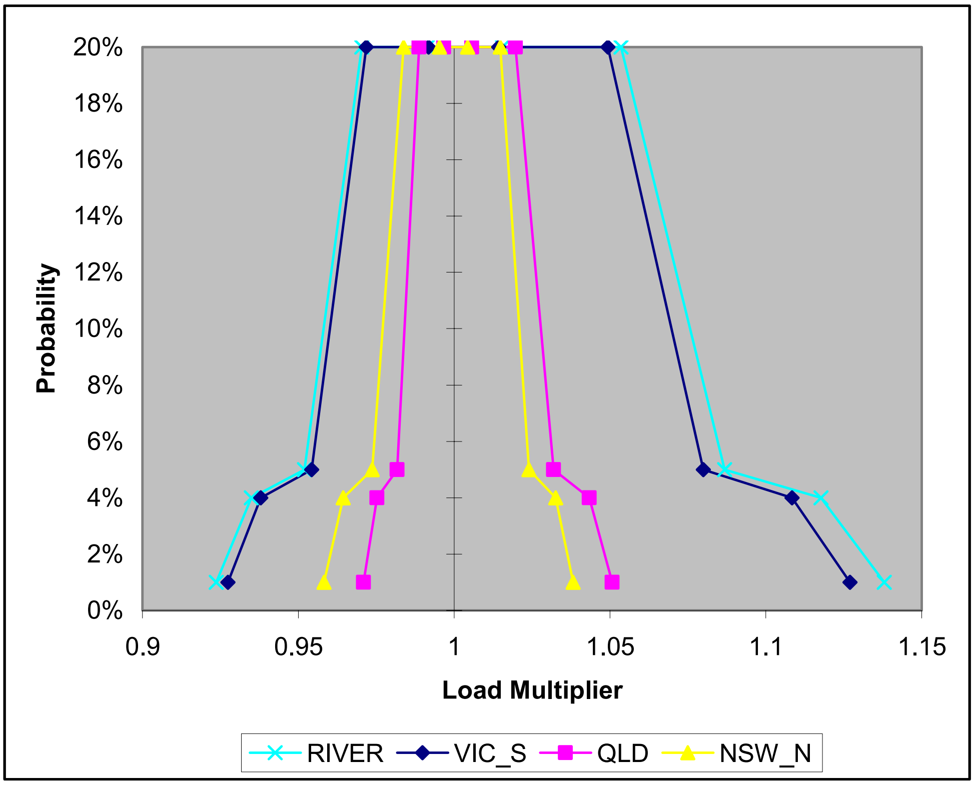


The abscissas $u_1 \ldots u_{10}$ define the boundaries of the bins. Note that the $u_5 = u_6 = 1$. The multipliers used by MARS are approximated for all except the highest and lowest band by using the mid-point of each bin. For example, the multiplier for the second highest band is $\frac{u_1 + u_2}{2}$. The multipliers used for the highest and lowest bands are u_1 and u_{10}, respectively.

Table 2.3 TEUS's demand multipliers and their associated probability of occurrence

Sub-region	Bin Probability									
	1%	**4%**	**5%**	**20%**	**20%**	**20%**	**20%**	**5%**	**4%**	**1%**
QLD	1.0507	1.0433	1.0319	1.0197	1.0057	0.9967	0.9887	0.9817	0.9752	0.9709
NSW_N	1.0382	1.0326	1.0240	1.0148	1.0043	0.9953	0.9838	0.9737	0.9644	0.9582
WAGGA	1.0382	1.0326	1.0240	1.0148	1.0043	0.9953	0.9838	0.9737	0.9644	0.9582
BURONGA	1.0382	1.0326	1.0240	1.0148	1.0043	0.9953	0.9838	0.9737	0.9644	0.9582
SNOWY	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
VIC_S	1.1270	1.1084	1.0799	1.0493	1.0143	0.9918	0.9718	0.9543	0.9380	0.9274
REDCLIFF	1.1270	1.1084	1.0799	1.0493	1.0143	0.9918	0.9718	0.9543	0.9380	0.9274
RIVER	1.1380	1.1177	1.0868	1.0535	1.0155	0.9914	0.9704	0.9520	0.9349	0.9237
SAW	1.1380	1.1177	1.0868	1.0535	1.0155	0.9914	0.9704	0.9520	0.9349	0.9237

Figure 2.2 TEUS's demand multipliers and their associated probability of occurrence (graphical view)



For each region, MARS multiplies the central demand forecast (50% PoE) by each of the ten load multipliers and applies the associated probability weighting that is depicted by the markers in the chart above.

Calculations of market benefit are sensitive to the 10% PoE demands. The initial market simulations undertaken for the SNI study showed that the economic benefits for the 90% PoE load traces were practically identical to the 50% PoE cases, and consequently the 90% PoE results were excluded from the SNI analysis.[21]

Therefore, the half-normal distribution on the right hand side is likely to be more critical than the left hand distribution when modelling Murraylink. This may reduce the impact of problems that might arise from the discontinuity that occurs where the two distributions meet.

TEUS's methodology, in essence, identifies ten yearly demand multipliers rather than hourly demand multipliers. Its effectiveness depends on:

- the consistency, throughout the year, of the IRPC's 10% PoE / 50% PoE and 90% PoE / 50% PoE hourly ratios. If there is large variability in the 10% PoE/50% PoE ratios, peak demands may be underrepresented as a result of the averaging process;
- whether the 10% PoE/50% PoE ratios would have been significantly different if the IRPC's half-hourly ratios (instead of the derived hourly ratios) had been averaged over the ten years.

TEUS's representation of weather-related loads in MARS is synthesised from IRPC data, and by being averaged over time, some chronological sequence information is lost (e.g. through the averaging of the 50% PoE half hourly loads into hourly data and the compressing of the 10% PoE and 90% PoE data for each region into single annual ratios).

The primary addition to the IRPC data in the synthesis process is TEUS's distribution curve assumption. The IRPC has assumed that the 1996/97 South Australian demands have a 10% PoE and the 1994/95 demands have a 50% PoE. Based on this assumption and an observation that the average hourly ratio between the 1996 and the 1994 demands is 1.076, the MARS modelling assumes there is a 1% probability that South Australian demand will be 113.80% of the central demand forecast, a 4% probability of being 111.77%, a 5% probability of being 108.60% and a 20% probability of being 105.35%.

A different distribution assumption or a different number of "bins" would have produced different results. Furthermore, the finite number of "bins" means that while synthesis started out by assuming that there was a 10% probability of demand meeting or exceeding 107.60 of the central demand forecast, it has ended by modelling a 10% probability (1%+4%+5%) that demand will meet or exceed 108.68% of the central demand forecast.

[21] SNI Stage 2 Report, IRPC, Version 07, 26 October 2001, p7.

TEUS has reasonably assumed that demands higher than the IRPC's 10% PoE demand sets should be stochastically modelled, but have not fully documented its justification for its assertion of how much higher these demands should be and what their associated probability of occurrence should be.

2.3.2 Alternative market development scenarios

The market benefits test requires consideration of a range of alternative market development scenarios. There are four broad categories of projects and investments, at various stages of planning, commissioning and completion that may impact the market benefit of a project and must be considered in market benefit analysis. These projects categories are:

1) committed projects (under construction);

2) anticipated projects (advanced planning);

3) modelled projects (likely to be commissioned); and

4) any other projects.

For ease of review we categorise 1 and 2, then 3 and 4 separately. The following two sections review the modelling assumptions made by TEUS in generation and transmission projects as inputs to the model. Where appropriate, comparisons are made with the analysis carried out for the SNI and other relevant precedents.

The third section looks at residual values and looks at how the model makes a selection when the annual benefits from the deferral of capital expenditure on new generation are zero.

Finally we review the treatment of deferred augmentation of transmission in Riverland and the treatment of the proposed SNI interconnector in the models.

Committed and anticipated projects

The market benefits test requires that:

> *(5) In determining the market benefit, the analysis should include modelling a range of reasonable alternative market development scenarios….These market development scenarios should include:*
>
> *(a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (committed projects);*

> *(b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (anticipated projects).*

The modelling assumptions for existing generation plant (committed and anticipated projects) in both PROSYM and MARS are based on those used in the SNI study. The assumptions used to define the characteristics of individual plant are:

- region;
- summer & winter maximum MW ratings;
- marginal loss factors;
- forced outage rate (FOR);
- annual maintenance requirement;
- mean time to repair; and
- short run marginal cost.

The data has, for the most part, been sourced from the IRPC's specifications in the SNI study.

Region

The regional location of all existing and committed stations are identical in the SNI and TEUS studies. [22] [23]

Summer and winter maximum MW ratings

The summer & winter capacity ratings of all existing and committed stations are identical in the two studies.

Marginal loss factors

The intra-regional loss factors used for most of the existing stations are identical.

[22] The original documentation provided appeared to classify Blowering as being in the Snowy rather than the New South Wales region. MTC has advised us that contrary to the information provided in the Application, Blowering was in fact correctly located in NSW in PROSYM modelling.

[23] We have taken the committed capacity to comprise the 550 MW of committed OCGT capacity. However, on page 8 of the ROAM assumptions report (but not in the IRPC reports) on the SNI and SNOVIC modelling, the following stations were classed as committed stations: Callide C, Millmerran, Swanbank E, Tarong North, Liddell, and Munmorah.

Table 2.4 Comparison of Inter-regional loss factors

Inter-regional loss factors – a comparison			
Station category	**SNI**	**TEUS**	**Stations**
New entrant OCGT , CCGT[24]	1.0000	1.0000	Kangaroo Valley 1, Kangaroo Valley 2, Energy Brix Complex 1, Energy Brix Complex 2-01, Energy Brix Complex 2-02, Energy Brix Complex 2-03, Energy Brix Complex 3, SA-GT 1–3, and Vic-GT 1–8.
Murray 1 and 2	1.0000	1.0001	Murray 1 and 2
Blowering	0.9808	0.9898	Blowering
Eraring 1 & 2[25]	0.9823	0.9841	Eraring 1 & 2

Forced outage rate, annual maintenance requirement and mean time to repair

There are some differences between the IRPC's rules for assigning forced outage rates and annual maintenance days and the figures used for some plant in the TEUS report. These are:

- TEUS has modelled each of the peaking stations Blowering, Hume-NSW, Hunter Valley 1&2, Kangaroo Valley 1&2, and Hume-Vic with a zero forced outage rate. Mintaro and Bairnsdale have been modelled with a 1% forced outage rate instead of the 4.46% and 1.15% that, respectively, have been assigned to those regions in the SNI report's forced outage rate FOR tables.
- TEUS has modelled Swanbank E and Playford 1–4 with, respectively, 14 and 32 maintenance days per year.

Both the SNI study and the TEUS study have applied a FOR of 1% and a mean time to repair of 24 hours for the new committed open cycle gas turbine OCGT plant.[26]

TEUS has assumed perfect reliability for the Snowy hydro plant (apart from Tumut 3 unit 1 which both studies assume is out of service). The Snowy data is confidential, and the IRPC has noted that for market

24 Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p12.

25 The IRPC Stage 1 report sets a marginal loss factor of 0.9823 for 2 of the 4 units, and 0.9841 for the other 2 units. MTC has advised that MARS has used the 0.9841 setting for all 4 units. The PROSYM modelling has taken a simple average of the two factors for each of the 4 units.

26 Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p13.

simulations it is acceptable to assume that the Snowy generators are perfectly reliable (a FOR of zero).[27]

Although TEUS modelling sources the FORs, mean times to repair, and planned maintenance periods of generation plant from the IRPC's SNI study specifications, their parameters are implemented differently in the two studies.

MARS requires that planned maintenance periods be specified by an integral number of weeks and so the SNI figures have been rounded.

MARS models partial states of unplanned outages, using a transition matrix to represent the probabilities of a generation plant moving from one outage state to another. TEUS has derived an estimate of the matrix values from the forced outage rates and the mean times to repair in the IRPC reports. The accuracy of the information may have been lost in this process since the mean times to repair figures that TEUS used to synthesise partial outage rates were, according to the ROAM reports, derived using ROAM Consulting's 2-4-C simulation package from more detailed data that included the partial forced outage rate.[28]

Short run marginal cost

The short run marginal costs for all of the existing stations were taken from the IRPC Stage 1 Report, and in both the IRPC and TEUS studies the SRMC of the committed OCGT capacity in South Australia (SA-GT 1–3), and 400 MW of committed OCGT capacity in Victoria (SA-GT 1–8) is modelled as $40/kWh.

Modelled and other projects

The market benefits test requires that:

> *(5) In determining the market benefit, the analysis should include modelling a range of reasonable alternative market development scenarios….These market development scenarios should include:*
>
> *(c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant (modelled projects).*
>
> *(d) any other projects identified during the consultation process.*

In the TEUS study, an algorithm in the PROSYM modelling determines in each year whether there is a sufficient market premium to allow for a new

27 SNI Stage 1 Report, IRPC, Version 014, 26 October 2001, p25, p48. p34.

28 Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p13.

market generator to enter the market. Using an algorithm to determine when new plant will enter the market provides reproducible results, a desirable feature when calculating the difference between two model runs.

Four types of new generation plant are evaluated for commissioning:

1) open cycle gas turbine;

2) combined cycle gas turbine;

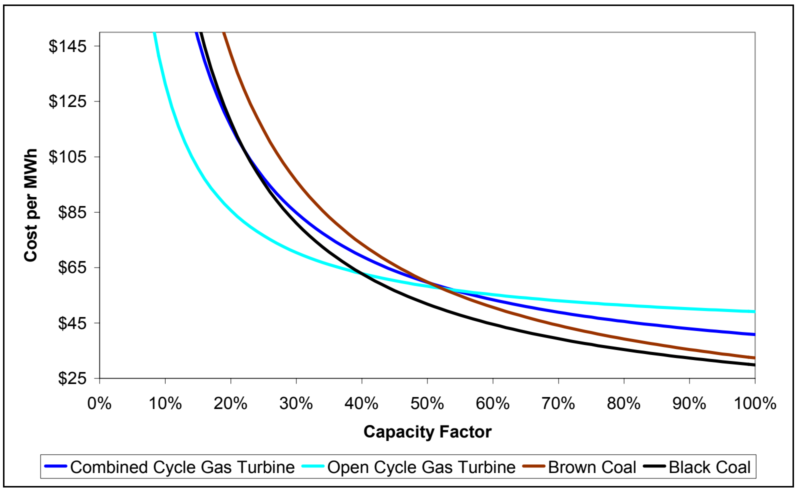
3) black coal; and

4) brown coal.

In addition to new generation, there are four bands of voluntary interruptible load.

Different types of plant are available in different regions, and each type has a different size, annuitised capital cost, and SRMC. TEUS has sourced the size, cost and SRMC data from the IRPC Stage 1 Report. As can be seen from the chart below, on a cost minimisation basis, the choice of plant type is sensitive to the amount of use that will be made of it during its lifetime.

Figure 2.3 Cost of new generation by plant size



Decisions that concern the commissioning of new plant can have a significant effect on the market benefits of an interconnector.

The TEUS algorithm does not have look-ahead capability. In the TEUS algorithm the investment decision is determined only by the plant's profitability in its commissioning year. It is therefore unable to confirm:

(a) whether the new plant would continue to operate profitably after its year of commissioning (partly a market-driven development issue), or

(b) whether it would have been more profitable for a merchant generator to have built a different type of plant that has a higher capital cost and lower operating cost, but which would have remained profitable over the entire period modelled (partly a least cost development issue).

As a result, the algorithm may be biased toward commissioning more low capital cost/high operating cost generation capacity than would be least cost in the long run. There is clearly a trade-off between the benefits of deferred market entry and fuel cost savings here, which PROSYM is not designed to handle.

The market premium for new generation is a function of the amount of voluntary interruptible load and, after that, of the unserved energy that would occur if the generation was not commissioned. Because there is no feedback of data from MARS to PROSYM, the rough estimates from PROSYM must be used to calculate the market premium. If any of the decisions to commission plant are affected by the error in the estimate of the market premium, then the model could build capacity too early or too late. This effect could produce error in the commissioning schedules that could potentially affect estimated generation deferral benefits, voluntary load curtailment costs, and unserved energy savings.

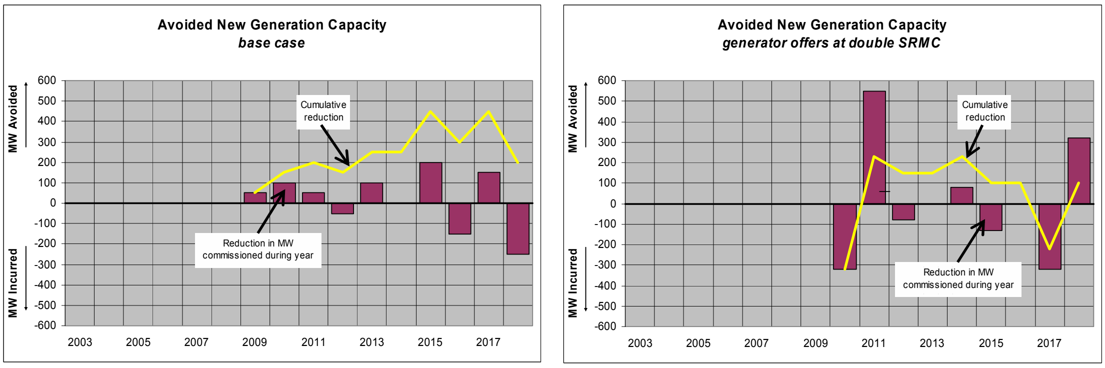
Discrete changes in the commissioning schedules can also be caused by minimum unit sizes being assumed for new plant and annual (rather than quarterly or monthly) commissioning dates.

Modelling residual values

TEUS sets the annual benefits from the deferral of merchant entry capital expenditure at zero after 2012. This implicitly assumes that by 2012 the modelling has reached long run market equilibrium both ″with″ and “without“ Murraylink. Because the interconnector is expected to permanently defer some new capacity, the cumulative capacity of the generation plant that has been deferred should, beyond 2012 zig-zag around the long term average set by the 2012 value.

At SEIL's request, TEUS extended the base case economic growth scenario computations to 2018, and ran an alternative development scenario which evaluated the impact on commissioning schedules of generator offers that are twice their SRMCs. The chart to the left, below, suggests that in the base case, the modelling may not have reached long run equilibrium in 2012 when 150 MW of new generation had been deferred and that it is slightly more likely to have stabilised (if at all) at 300 MW in 2016. However, it appears unlikely that Murraylink could in fact permanently replace 300MW of generation capacity. The chart to the right suggests that with higher offer prices the generation deferral may possibly stabilise in the model at around 100 MW.

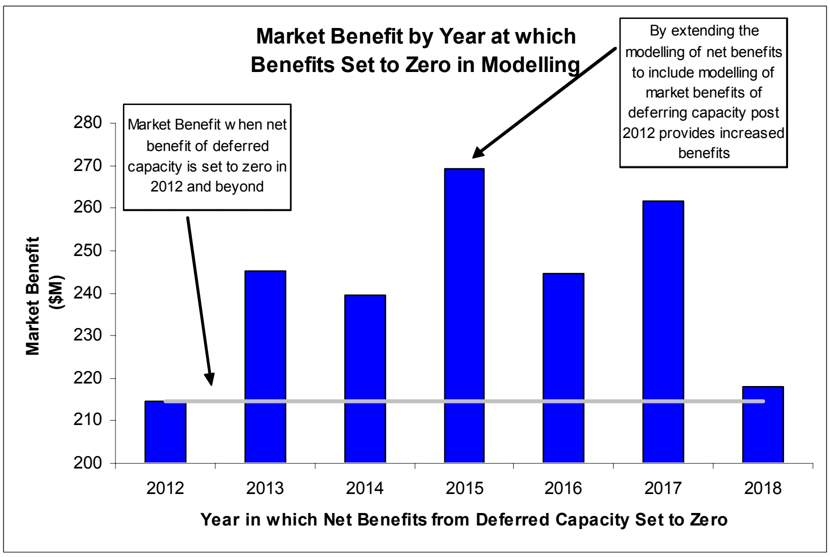
Figure 2.4 MW capacity of new generation plant commissioned under two bidding scenarios



Another test for long run equilibrium is to continue extending the computations to include additional years until the 40 year market benefit calculations stabilise. As can be seen from the chart below, extending the last year of computations by up to 5 years beyond 2012 would have markedly increased the 40 year NPV. Only when the computations extend to 2018 in the base case does the market benefit drop back toward the value estimated when the computations were made out to 2012.

The chart indicates that TEUS has acted conservatively when it computed the results to 2012 and applied residual values beyond that date. However, we note that the sensitivity that the market benefit forecasts exhibit according to the manner in which the residuals have been calculated may have implications for consistency.

Figure 2.5 Impact of modelling NPV of Market Benefits



Riverland deferred augmentation of network

The Riverland area has experienced significant above average growth in electricity consumption, resulting in supply constraints and pressure on the performance and reliability of the South Australian electricity infrastructure.[29] The newly constructed Murraylink interconnector provides some of the infrastructure requirements to alleviate this supply pressure; however it appears the supply constraints identified have been delayed rather than removed, with additional investment required over the planning timeframe.

Murraylink was one of a number of potential solutions to the supply issues facing Riverland considered by the ESIPC. These solutions included the provision of additional generation capacity and further transmission augmentation in the Riverland area. The SNI transmission interconnector between Victoria and South Australia is currently under consideration to further alleviate supply issues, in addition to further augmentation of the Riverland network via the proposed construction of the Riverlands 275kV transmission line.

TEUS has calculated the market benefit of deferring Riverland's infrastructure requirements on the basis that the SNI project does not proceed. It has calculated market benefit figures based on an adjustment of ESIPC planning horizons in line with revised ESIPC load forecasts.[30] Although detailed analysis has not been undertaken by us, it would be reasonable to assume that the downwardly revised ESIPC load forecasts might lead to a deferral of the infrastructure developments to supply Riverland as well.

TEUS analysis has taken into account ESIPC's revised load forecasts for 2002 and assumes that under a base case economic growth scenario the Murraylink Interconnector defers:

- from 2003 to 2013, the need for capital expenditure on a transmission line thermal upgrade costing $40m;
- from 2003 to 2008 the need for capital expenditure on capacitor banks costing $0.5m; and
- in the low growth case, the thermal upgrades are deferred until 2018. In the high growth case, the thermal upgrade deferral is only until 2011.

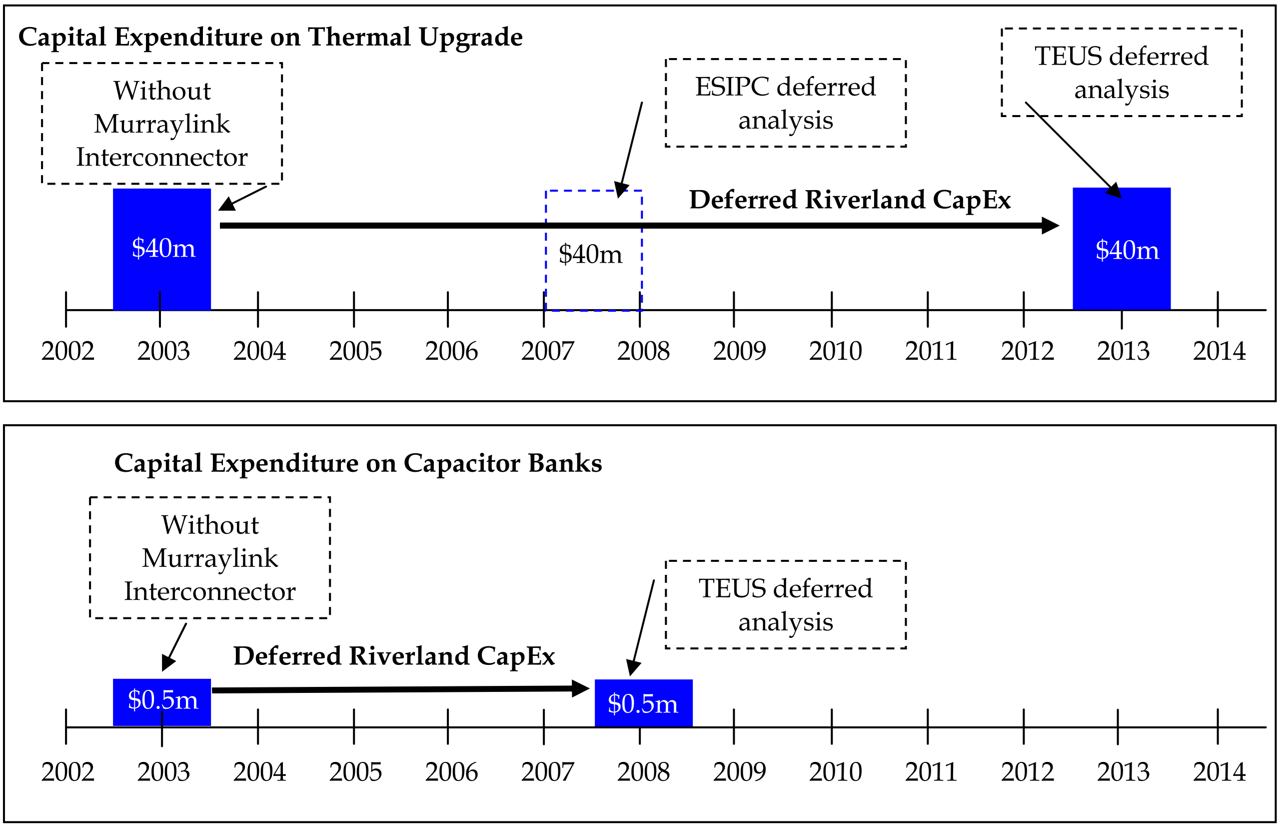
Assuming that the magnitude of the costings is correct, we have tested the sensitivity of the market benefit to the timing of the expenditure on the thermal upgrade. Bringing the $40m thermal upgrade capital expenditure

[29] The Riverland Augmentation Final Technical Report (ESIPC), December 2001

[30] Figures calculated in the Riverland Augmentation Final Technical Report (2001) have been adjusted by TEUS for revised ESIPC load forecasts for 2002, in line load forecasts which have been revised downward.

forward from 2013 to 2012 or 2011 would, when a 9.25% discount rate is applied, reduce the total market benefits by $1.5m and $3.2m respectively.

Figure 2.6 Deferred Capital Expenditure – Murraylink Interconnector



These findings appear to compare favourably with ESIPC's 2001 findings. If the Murraylink interconnector is fully operational and the network has full system capability ESIPC (2001) analysis indicates acceptable performance levels will be satisfied past the planning horizon. Under a scenario where the Murraylink interconnector is not in service, inadequate reactive power support would be provided from 2007/08 onwards.

2.3.3 Evaluation time horizon

TEUS has evaluated the market benefits over a planning horizon that extends from 1 May 2003 through to 30 September 2042. The first ten years of the analysis were computed using the modelling techniques described above; the subsequent years were evaluated as residual values (holding market benefits values constant from year 11 onward, and then discounting back to present value terms).

There has been little consistency in this aspect of the market benefits test across similar studies. The IRPC's SNI study derived residual terms by applying a uniform series present worth factor to all streams apart from the merchant entry and the Riverland deferral benefits, to effectively apply an infinite planning horizon.[31] VENCorp's Latrobe Valley to Melbourne study calculates benefits over 10 year planning horizon 2002/3–2011/2.[32]

2.3.4 Inflation assumptions

The cost and financial assumptions used by TEUS have been sourced from the IRPC Stage 1 Report.

TEUS has assumed that the IRPC compiled these figures at around September 2000 and expressed them in dollars-of-the-day terms. For the period 30 September 2000 to 1 May 2002, TEUS has indexed all short run marginal costs of generation and capital costs of new generation to the Australian All Cities CPI.

In responding to a SEIL request for clarification, TEUS quoted an IRPC Stage 1 report dated July 1999 that includes references to the same baseline costs.[33] We have not sourced this earlier IRPC report, but accept TEUS' argument that it has been conservative in applying a September 2000 assumption.

ROAM Consulting undertook the SNI market benefits test analysis for NEMMCO and the IRPC. Its assumptions report indicates that it has assumed that the IRPC figures are in 2003/4 dollars.[34] We have not confirmed this with ROAM Consulting. Similarly, VENCorp studies appear to have assumed that the SRMCs and LRMCs that were prepared by the IRPC share the same base year as the VENCorp's own estimates of the capital cost of the Latrobe to Melbourne augmentation. At least one of the two companies appears to have assumed that VoLL is indexed to the same inflator as fuels costs and capital cost. The value of VoLL is specified in the Code with no inflation parameter.

There appears to be little consistency in the way that inflation is accounted for (if at all) in applications of the market benefits test to date. We can find no clear precedent in applications of the market benefits test for TEUS's use of the CPI as an inflator for SRMC, the generic capital costs of new generation, the costs of voluntary load interruptions and VoLL.

Indexing VoLL as has been done implicitly by TEUS (holding VoLL at constant real dollars, as opposed to constant nominal dollars) may have merit as a proxy for consumers' value of lost load, but may diverge from the setting of VoLL under the Code.

2.3.5 Discount rates

The market benefit test requires that:

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[31] Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p26; SNI Stage 2 Report, IRPC, Version 07, 26 October 2001, p10.

[32] Economic evaluation: Optimising the Latrobe Valley to Melbourne electricity transmission capacity, VENCorp, February 2002, p8.

[33] Email correspondence, Sandra Gamble (Allen Consulting Group) 13 December 2002.

[34] Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p23.

> *For the purposes of the test*
>
> *(c) the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector;*
>
> *(d) the calculation of the market benefit or cost should encompass sensitivity analysis with respect to the key input variables, including capital and operating costs,* ***the discount rate*** *and the commissioning date, in order to demonstrate the robustness of the analysis.*

Deloitte Touche Tohmatsu has indicated to TEUS that a real, pre-tax discount rate in the range of 7.76% p.a. to 10.40% p.a. would be appropriate for the TEUS study. [35] The Application has been prepared using a discount rate of 9.25% p.a. No sensitivity analysis around the discount rate has been reported.

As can be seen from the Deloitte Touche Tomatsu discount rate table that was appended to the Application and reproduced below, there is considerable divergence in regard to the setting of a discount rate for the purpose at hand.

[35] Letter from Deloitte Touche Tomatsu to the Murraylink Transmission Partnership, 16 October 2002, in Appendix C of the Murraylink application.

Table 2.5 Comparison of discount rates from Deloitte Touche Tohmatsu 16 October letter

Variable	Murraylink (Officer)	VENCorp	IRPC	ElectraNet SA	Murraylink-Low	Murraylink-High	Murraylink-Base
	Regulatory	Market Benefits					
Expected Inflation Rate	2.20%	n/a	n/a	n/a	2.20%	2.20%	2.20%
Nominal Risk-Free Rate	5.40%	n/a	n/a	n/a	5.40%	n/r	5.40%
Nominal Cost of Debt	6.90%	n/a	n/a	n/a	6.90%	9.00%	6.90%
Real Cost of Debt	4.7%	n/a	9.0%	n/a	4.7%	6.8%	4.7%
Equity Beta	1.13	n/a	n/a	n/a	1.13	n/r	1.64
Market Risk Premium	6.00%	n/a	n/a	n/a	6.00%	n/r	6.00%
Nominal Post Tax Return on Equity	12.15%	n/a	n/a	n/a	12.15%	n/r	15.26%
Corporate Tax Rate	30%	n/a	30%	n/a	30%	n/r	30%
Value of Imputation Credits	45%	n/a	50%	n/a	45%	n/r	45%
Nominal Pre Tax Return on Equity	14.55%	n/a	n/a	n/a	14.55%	18.00%	18.28%
Real Pre Tax Return on Equity	12.35%	n/a	18.00%	n/a	12.35%	15.80%	16.08%
Debt Funding	60.00%	n/a	65.00%	n/a	60.00%	60.00%	60.00%
Real, pre-tax WACC (discount factor)	**7.76%**	**8.00%**	**11.00%**	**13.00%**	**7.76%**	**10.40%**	**9.25%**

Notes:

n/a: not available

n/r: not required

VENCorp discount rate was used for both SNO VIC and the Latrobe Valley to Melbourne analysis

IRPC discount rate was used for both SNOVIC and SNI analysis

The SNI study used a real pre-tax commercial discount rate of 11% with sensitivities of 9% and 13%.[36] VENCorp, in its Latrobe Valley to Melbourne study, used a real pre-tax discount rate of 8%, with sensitivities at 6% and 10%.[37]

[36] SNI Stage 1 Report, IRPC, Version 014, 26 October 2001, p32.

[37] Electricity Annual Planning Review 2002: Appendices, VENCorp, pA12

To illustrate the materiality of the matter, we have simply calculated the stream of market benefits as provided by TEUS under the range of discount rates suggested by Deloitte Touche Tomatsu.

Table 2.6 Sensitivity of NPV of market benefits to alternative discount rates*.

Discount Rate	**Low = 7.76%**	**Base = 9.25%**	**High = 10.40%**
NPV Market Benefits	$245,388 m	$215,061 m**	$196,412 m

* Discount rates assumptions from Deloitte Touche Tomatsu Appendix C

** Calculation of the NPV of market benefits @ 9.25% varies slightly from Application due to use of annual data by us as opposed to monthly data used by TEUS. This calculation is for illustrative purposes only.

This illustration only shows the first order effects of the discount rate. There would be other less direct effects as well in estimation of the various factors contributing to annual estimates of market benefits. These factors would probably be of lesser magnitude.

2.3.6 Generator offer behaviour

The market benefits test states that:

> *(6) Modelled projects should be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.*
>
> > *(a) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs.*
> >
> > *(b) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price trends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those*

most likely to occur under actual systems and market outcomes.

With regard to the SNI study, the IRPC stated that a least cost planning scenario differs from a SRMC market development scenario to the extent that new reliability driven entry should be offered into the NEM at SRMC rather than at VoLL.[38]

Because no reliability entry generation is modelled in PROSYM[39], the distinction drawn by the IRPC between the two forms of analysis is of little help in determining whether TEUS have applied a least cost market development approach or a market-driven development approach in its modelling. In response to our question concerning which approach has been taken for the Murraylink study, TEUS state:[39]

> *"TEUS considers the market benefits analysis to be a simulation of market-driven development, using a short run marginal cost bidding strategy. As a consequence, it produces market entry results that are very similar to what a least cost market development would produce because bids are equivalent to short run marginal costs."*

For the SNI and SNOVIC market modelling, simulations were carried out using two different generator offer strategies. In the first, generators were assumed to offer into the market at short run marginal cost (with reliability-driven plant offered in at VoLL), and in the second, they were assumed to offer in long run marginal cost. A further, "Least Cost Planning" scenario was also modelled, in which all plant, including reliability driven plant, was assumed to be offered at short run marginal cost.

The three market development scenarios in the TEUS report differ only in their forecasts of economic growth. All scenarios use SRMC bidding for existing, committed, and market entry generators. MTC has used the market benefit forecast for the base case economic growth assumption in preparing its proposed regulatory asset value. The market benefits test provides no guidelines on how to combine the market benefits of several market development scenarios into a single result.

2.3.7 Demand-side bidding

The SNI study incorporated demand-side participation in Victoria and South Australia, whereby a total of 3% of the 10% PoE load forecast region would be voluntarily reduced in four price bands.

38 SNI Stage 2 Report, IRPC, Version 07, 26 October 2001, p51.

39 MTC response to question 1.7 of SEIL information request, seil_1-7.doc, 3 December 2002.

Table 2.7 SNI study—level of Demand side participation available in Vic & SA

Pool Price	Demand Side Participation Represented
$500/MWh	0.45 % of the maximum regional demand (10% PoE)
$1,000/MWh	0.60 % of the maximum regional demand (10% PoE)
$3,000/MWh	0.90 % of the maximum regional demand (10% PoE)
$5,000/MWh	1.05 % of the maximum regional demand (10% PoE)

TEUS has applied the same demand-side representation quantities and price step. The TEUS report implies that it has been applied to all four regions rather than just Victoria and South Australia. We note that although the IRPC has stated that only the two regions were reported in the NEMMCO 2001 Statement of Opportunities, ROAM Consulting advised that extending demand side participation (DSP) modelling to the other regions of the market would have a negligible impact on the outcome of the SNI analysis.[40]

The IRPC has stated that a reduction in demand side participation is a benefit to the market. The SNI study assumed a value of $500/MWh for all savings in demand side participation, whichever block it was priced at.[41] However, TEUS appears to have valued the savings at the bid prices of the individual blocks i.e., $500/MWh, $1,000/MWh, $3,000/MWh, and $5,000/MWh.[42]

2.3.8 Reliability-driven generation

The market benefits test states that:

> *(1) In determining the market benefit, the following information should be considered:*
>
> *(b) reasonable forecasts of:*
>
> *ii. the value of energy to electricity consumers as reflected in the level of VoLL;*

and

> *(5) In determining the market benefit, the analysis should include modelling a range of reasonable alternative market development scenarios….These scenarios should include projects undertaken to ensure that relevant reliability standards are met.*

40 SNI Stage 2 Report, IRPC, Version 07, 26 October 2001, p7.

41 SNI Stage 2 Report, IRPC, Version 07, 26 October 2001, p11, . Economic Evaluation of the Proposed SNI Interconnector—Assumptions, ROAM Consulting, 26th October 2001, p24.

42 Estimation of Murraylink Market Benefits, TransÉnergie US Ltd, undated, in Appendix D of the Murraylink application, p17.

In any given year, market driven entry might not provide sufficient generation to meet the reliability standards. The modelling for both the IRPC's SNI study and VENCorp's Latrobe Valley to Melbourne study have overcome this by expanding capacity to the reliability entry level by adding new generators. According to VENCorp, the criteria for assessing the size and location of reliability entry are:

- sufficient additional reliability generation is required to maintain sufficient reserve margin in each region;
- the interconnectors must remain within the limits defined by their modelled capabilities; and
- the 10% PoE load traces define the level of coincidence between maximum demands in the regions.

VENCorp's study report states that its reliability plant is offered into the market at SRMC for all market scenarios except for the LRMC case.

The IRPC's SNI reports state that its reliability plant is offered into the market at VoLL for all market scenarios[43] except for the least cost planning scenario (which offers the reliability plant into the market at SRMC)[44].

The reserve levels used in the SNI studies (and also in VENCorp's Latrobe Valley to Melbourne studies) are shown in the table below.

Table 2.8 SNI project minimum reserve levels for each region

Region	QLD	NSW	Victoria	SA
Reserve trigger levels	420 MW	660 MW	500 MW	260 MW

In the TEUS study, no reliability plant is commissioned. All unserved energy is costed at VoLL, the price at which the IRPC's SNI reliability generation would be offered into the market in the SNI market scenarios. The two approaches are equivalent, except that in the SNI study, the construction of the SNI interconnector may have the added benefit of delaying the commissioning of reliability-driven generation. The TEUS study does not contemplate this additional source of benefit, but instead calculates the savings of avoided USE.

2.3.9 Conclusions on primary assumptions by TEUS

There are a range of primary and secondary assumptions which are required to solve for estimated market benefits. In many cases, the setting of these assumptions requires a considerable degree of professional judgment, as the factors on which these assumptions are based are "unobservable". That is, there is no clear benchmark in which to base one's judgment.

43 SNI Stage 1 Report, IRPC, Version 014, 26 October 2001, p25, p48. p27.

44 SNI Stage 2 Report, IRPC, Version 07, 26 October 2001, p8.

Nevertheless, there is a growing body of documented experience in the estimation of market benefits for the purpose of the regulatory test, which allows for some comparison between the assumptions made by experienced practitioners in this field.

In general, we find that many of the key assumptions employed by TEUS are broadly consistent with those of other recent studies which have estimated market benefits.

Where TEUS has employed a set of assumptions which vary from comparable studies, they have been reasonably transparent considering the complexity of such matters and practical difficulty of articulating them to a broad audience. While there may be room for professional debate on the specific setting of certain assumptions, we do not generally find the TEUS assumptions to be clearly in-appropriate.

However, one must recognize that there are a number of key assumptions which will have a direct and material impact on the estimated value of market benefits. We have discussed in detail some of these factors, and highlighted a set of those under which the estimate of market benefits is highly sensitive to.

This matter becomes significant within the context of the MTC Application, where the estimated value of market benefits provides the basis for the setting of the maximum allowable revenue which MTP would be allowed to recover from transmission customers[45].

2.4 TEUS' Findings in Regard to Market Benefits

TEUS assessed the 40yr NPV market benefits of the Murraylink Interconnector, over the period 2003 to 2042 to be $214.2m. In modelling this result TEUS identified six categories of market benefit attributable to the Murraylink Interconnector. These are:

- Energy Savings;
- Merchant Entry Capital Deferral;
- Avoided Merchant Entry O&M;
- Reliability Benefit;
- Riverland Capital Deferral; and
- Riverland O&M Deferral.

Table 2.9 provides the market benefits for each year of the modelled period by benefit category. Market Benefits have been calculated for years 2003 to 2012. From year 2013 onwards a constant (real) yearly market

45 This issue is discussed in more detail in section 4 of our Review.

benefit is assumed for the remaining years. The exception **is** a negative benefit of $40m capital expenditure on thermal upgrades in the Riverland area in 2013. This capital expenditure has been deferred from 2003 as a result of the Murraylink Interconnector (the benefits of which have been captured in 2003). This additional upgrade is modelled as the construction of a $40m transmission line from Monash to Robertstown.

Table 2.9 Market Benefits by Benefit Category

Market Benefits by Category, 2003 – 2042							
Date	Benefit Category						
	Energy Savings	Merchant Entry Capital Deferral	Avoided Merchant Entry O&M	Reliability Benefit	Riverland Capital Deferral	Riverland O&M Deferral	Total
	(‘000)	(‘000)	(‘000)	(‘000)	(‘000)	(‘000)	(‘000)
2003	3,309	-	-	15	40,500	192	44,016
2004	5,946	-	-	55	-	288	6,290
2005	5,765	-	-	199	-	288	6,253
2006	6,283	-	-	415	-	288	6,987
2007	7,000	-	-	1,092	-	288	8,381
2008	8,132	-	-	3,050	(500)	288	10,970
2009	9,418	26,760	268	4,275	-	288	41,009
2010	9,119	53,520	803	6,835	-	288	70,564
2011	5,138	26,760	1,070	6,355	-	288	39,656
2012	7,602	(26,760)	803	9,407	-	288	(8,660)
2013	7,602	-	803	9,407	(40,000)	-	(22,188)
2014	7,602	-	803	9,407	-	-	17,812
2015	7,602	-	803	9,407	-	-	17,812
2016	7,602	-	803	9,407	-	-	17,812
2017	7,602	-	803	9,407	-	-	17,812
2018	7,602	-	803	9,407	-	-	17,812
2019	7,602	-	803	9,407	-	-	17,812
2020	7,602	-	803	9,407	-	-	17,812
2021	7,602	-	803	9,407	-	-	17,812
2022	7,602	-	803	9,407	-	-	17,812
2023	7,602	-	803	9,407	-	-	17,812
2024	7,602	-	803	9,407	-	-	17,812
2025	7,602	-	803	9,407	-	-	17,812
2026	7,602	-	803	9,407	-	-	17,812
2027	7,602	-	803	9,407	-	-	17,812
2028	7,602	-	803	9,407	-	-	17,812
2029	7,602	-	803	9,407	-	-	17,812
2030	7,602	-	803	9,407	-	-	17,812
2031	7,602	-	803	9,407	-	-	17,812
2032	7,602	-	803	9,407	-	-	17,812
2033	7,602	-	803	9,407	-	-	17,812
2034	7,602	-	803	9,407	-	-	17,812
2035	7,602	-	803	9,407	-	-	17,812
2036	7,602	-	803	9,407	-	-	17,812
2037	7,602	-	803	9,407	-	-	17,812
2038	7,602	-	803	9,407	-	-	17,812
2039	7,602	-	803	9,407	-	-	17,812
2040	7,602	-	803	9,407	-	-	17,812
2041	7,602	-	803	9,407	-	-	17,812
2042	6,981	-	602	3,674	-	-	11,257

The NPV calculated from the data reproduced here diverges slightly from the TEUS calculation due to our use of yearly figures as reported in the Application, as opposed to the use of monthly data by TEUS.

2.4.1 Comments on TEUS' findings

It is difficult to comment directly on the findings produced by TEUS as there are no directly observable benchmarks in which to base such analysis. As estimated values, the critical issues to consider are those which we have previously addressed – methodology, choice of assumptions, and sensitivity of results to those factors.

Given the importance of the findings provided by TEUS (that is, the estimated value of market benefits) we recommend that further assessment be carried out. This would include review of areas such as:

- the modelling procedures employed by TEUS;
- raw data inputs to the models;
- key data outputs;
- calculations of final summary measures used to "build up" the value of market benefits; and
- "stress test" of the model outputs to better determine the sensitivity of results to key inputs.

We believe particular attention is warranted in regard to the modelling technique applied in estimation of merchant generation entry, in which further analysis should be undertaken to more clearly assess its robustness to a well defined set of key assumptions. The aim here is to obtain a robust estimate of the value of generation deferrals.

Addendum – Power Transfer Capability

The Commission, in parallel to our Review, has engaged PB Associates to provide a review of the power transfer capability provided by Murraylink. PB Associates have recommended that further dynamic studies be undertaken in regard to certain assumed power transfer limits[46]. Depending on the findings of those studies, additional modelling may be required in re-estimation of the value of market benefits.

[46] PB Associates Transfer Capability Review of the Murraylink Application to ACCC. January 2003.(pages 35-36)

3 REVIEW OF ALTERNATIVE PROJECTS AS ASSESSED BY BURNS AND ROE WORLEY

3.1 BRW Report

Burns and Roe Worley (BRW) were engaged by Trans Energie Australia (TEA) on behalf of MTC to prepare a report to select and assess alternative projects that offer the same technical service (and hence the same market benefits) as Murraylink. The purpose of considering these alternatives is to determine whether there are other transmission projects that could provide the same (or very similar services) to those provided by Murraylink, but at a lower cost. The lowest cost project would then set an upper bound on the opening regulatory asset value (RAV) of Murraylink.

In this section, we assess whether:

- the alternative projects that have been selected by BRW are appropriate for the purpose of determining a DORC for Murraylink; and
- the estimated costs of the alternative projects conform with established methodologies that have been applied to the determination of DORC.

3.2 ORC Methodology

In its "Draft Statement of Principles for the Regulation of Transmission Revenues" (Draft Regulatory Principles) dated 27 May 1999, the Commission proposed using the ORC methodology (or the Depreciated Optimised Replacement Cost (DORC)) to set a cap on the valuation of the asset base of a Transmission Network Service Provider (TNSP). The Commission considered that a well-defined DORC approach has some significant advantages as a valuation methodology on economic efficiency grounds.

The Draft Regulatory Principles indicated that the Commission intended to release guidelines on its approach to DORC valuations before the end of 2002 but has not yet done so. Nevertheless, there is a general understanding of the DORC methodology, which has been in use in the New Zealand electricity sector since 1992 when it was used to set an opening asset valuation for Transpower New Zealand Limited. Its use has since been extended to all electricity lines businesses in New Zealand. The DORC methodology that is used in New Zealand is part of an overall Optimised Deprival Value (ODV) methodology which is prescribed in the "Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Lines Businesses" (ODV Handbook), published by the New Zealand Ministry of Economic Development.

3.3 Description of Murraylink

Murraylink is different from other recently-built transmission assets in a number of respects:

- As noted above, it is a single interconnector, rather than part of a TNSP's network.
- It was built to provide market network services, but is now applying to convert to a prescribed service. It has no pre-existing regulatory asset value (RAV).
- It uses relatively new HVDC Light technology. It provides a functionality that can only be provided for by a combination of other existing technologies.

3.3.1 Technical components of Murraylink

Murraylink is a 180km HVDC Light interconnection between the Red Cliffs substation in northwestern Victoria and the Monash substation in the south-eastern part of South Australia. It connects with the 220kV system in Victoria and the 132kV system in South Australia. There are AC/DC converter stations at Monash and Red Cliffs and underground AC cable ties that connect the converter stations to the AC systems at Monash and Red Cliffs.

In addition to the basic active power control and DC voltage control, Murraylink has AC voltage control, reactive power control and runback control. These additional controls enable Murraylink to provide enhanced services to the two networks to which it is connected.

3.3.2 Technical services provided by Murraylink

The technical services as provided by Murraylink (as set out in MTC's Application) are that it:

- Provides up to 220MW injection from Victoria into South Australia during light to moderate load periods and at least 110MW during high load periods. This can occur even when generation in Victoria is constrained and additional generation is sourced from New South Wales.
- Provides up to 220MW injection into Victoria from South Australia, subject to the load in the Riverland area in South Australia and generation constraints in South Australia. During times of heavy Riverland load, Murraylink is constrained in order to prevent overloading of the 132kV circuits between Robertstown and Monash.

- Maintains power transfer capability from Victoria into South Australia when the Heywood to South East interconnection between Victoria and South Australia is constrained.

- Provides reactive support and voltage regulation at both Monash and Red Cliffs substations. The reactive support ranges from 1110MVAr/+140MVAr during rectifier operation and –125MVAr/+120MVAr during inverter operation. The level of reactive support that is able to be provided by Murraylink is independent of the level and direction of real power transfer.

Other features of Murraylink that were identified by BRW as part of the technical services but were not required to be provided by the alternative projects (so were not included in their costs) were that it:

- provides rapid runback; and
- has a low environmental impact.

3.4 Selection of Alternative Projects

BRW's brief was to select a number of alternative projects and compare their costs to find the lowest cost alternative. They also considered generation and demand-side management as possible substitutes for Murraylink but these were discarded on the grounds that:

- the capital costs of the generation alternative of combined cycle gas turbine (CCGT) stations were similar to that of Murraylink before adding the costs of upgrades to the gas supply network that would be necessary to supply the new stations so were not a lower cost alternative; and

- demand side management on a scale comparable to the 220MW transfer capability of Murraylink was not feasible with the very flat Riverland load.

To select the alternative transmission projects, BRW carried out simplified load-flow studies to model Murraylink and the alternative projects. The technical requirements specified were that each of the alternatives should be capable of:

- delivering 220MW to South Australia from Victoria, Snowy or NSW under the same conditions as Murraylink;

- adequately controlling the voltage at Red Cliffs and Monash to prevent voltage sag or surge conditions; and

- relieving congestion in the South Australian network to the Riverland area.

On this basis, the alternative projects selected by BRW are:

- An AC interconnection between Buronga in southwest New South Wales (just north of Red Cliffs) to Monash using overhead line and underground cable. A 275kV AC line and cable was chosen to match the voltage used in most of the South Australian system. It would be operated at 220kV initially in order to connect with the existing 220kV Buronga-Darlington Point line but could be converted to 275kV operation later.

- A HVDC Light line between Monash and Red Cliffs that is identical to Murraylink except that it is mostly overhead line. It has 25km of tactical undergrounding.

- An AC interconnection between Monash and Red Cliffs using overhead line and underground cable. A 220kV line and cable were chosen, with no provision for future connection to the 275kV system in South Australia. Otherwise, this alternative is similar to the other AC option but over the same line route as the HVDC Light option.

- Two AC augmentations with a similar functionality to Murraylink. Unlike the other options that all have similar line routes, these augmentations are in two separate parts of the existing transmission systems. One of the augmentations increases supply to the Riverland area by increasing the capacity of the 275kV Robertstown-Monash line. The other increases imports into South Australia by upgrading the 275kV Heywood-South East interconnection.

The technical services provided by Murraylink's HVDC Light technology could not be exactly duplicated by the AC alternatives. The major difference between the technical services provided by Murraylink and the AC alternatives is the amount and controllability of reactive support and voltage regulation that Murraylink is able to provide. To provide similar reactive support and voltage regulation services, the AC alternatives require static var compensators (SVC) and shunt reactors. Another difference is that the AC alternatives require phase shifting transformers (PST) to provide a comparable degree of power flow control.

The technical components and the services provided by each of the alternatives are summarized in the following.

3.4.1 Alternative 1 – Buronga - Monash 275kV AC o/h line

Technical components of Alternative 1

The technical components of this alternative are:

- 180km of 275kV overhead line and 30km of 275kV underground cable;
- 2 x 275/132kV 160MVA transformers at Monash. 160MVA transformers were chosen to match the standard size used by ElectraNet;
- 275kV 350MVA PST +/-20° at Monash;
- SVC +120/-110MVAr at Monash; and
- 30MVAr reactor at Red Cliffs.

The line route for Alternative 1 is similar to that for SNI but includes some tactical undergrounding in the environmentally sensitive Ramsar wetland in the Bookmark Biosphere reserve in South Australia. The extent of undergrounding is that considered most likely to be required by Kellogg Brown & Root (KBR), BRW's environmental consultants. It is in the middle of the range of no undergrounding, which was considered possible but less likely, and a high degree of undergrounding (60km) to traverse the Bookmark Biosphere reserve.

Technical services provided by Alternative 1

Only differences from the services provided by Murraylink are described because the alternatives were chosen to provide technical services as close as possible to those provided by Murraylink. The differences between the technical services provided by Alternative 1 compared with Murraylink are that Alternative 1:

- has only partial control of the power flow over the interconnection depending on generation dispatch and PST tap changing (whereas Murraylink has full control over the power flow); and
- provides reactive support only at Monash. This is considered adequate to control voltage at Red Cliffs as well (whereas Murraylink can control voltage at Monash and Red Cliffs independently).

3.4.2 Alternative 2 – Monash–Red Cliffs 140kV HVDC o/h line

Technical components of Alternative 2

This alternative is the same as Murraylink except that a 155km overhead DC line is used over most of the line route, with 25km of underground cable. Otherwise, the technical components are the same as Murraylink's. The 25km of undergrounding is the extent of undergrounding considered most likely to be required by KBR to traverse settlements at Red Cliffs and Lyrup in South Australia. Although there is the possibility that no undergrounding would be required, it is considered less likely.

Technical services provided by Alternative 2

Alternative 2 provides technical services identical to Murraylink's.

3.4.3 Alternative 3 – Red Cliffs–Monash 220kV AC o/h line

Technical components of Alternative 3

The technical components of Alternative 3 are:

- 155km of 220kV overhead line and 25km of 275kV underground cable;
- 1 x 220/132kV 350MVA combined transformers/PST at Monash;
- SVC at Monash +120/-110MVAr at Monash;
- 30MVAr reactor at Red Cliffs.

The main difference between Alternative 3 and Alternative 1, apart from the different line route, is the substitution of a 220/132kV 350MVA combined transformer/PST for the two 275/132kV 160MVA transformers and a 275kV 350MVA PST +/-20° at Monash. The line route for Alternatives 2 and 3 are the same, so the extent of and reasons for, undergrounding are also the same.

Technical services provided by Alternative 3

The differences between the technical services provided by Alternative 3 and Murraylink are that Alternative 3:

- has only partial control of the power flow over the interconnection depending on generation dispatch and PST tap changing (whereas Murraylink has full control over the power flow); and
- provides reactive support at Monash only (whereas Murraylink can control voltage at both Monash and Red Cliffs independently). A switched shunt reactor at Red Cliffs is included in Alternative 3 to prevent severe overvoltages following a sudden disconnection of the 220kV interconnection.

3.4.4 Alternative 4 – augmentations to 275kV system

Technical components of Alternative 4

The technical components of the two separate augmentations in Alternative 4 are:

- 275kV o/h line in South Australia from Robertstown to Monash;

- 275kV o/h line from Heywood (in Victoria) to South East (in South Australia);
- 275/132kV 160MVA transformer at Monash;
- SVC +120/-110MVAr at Monash;
- 30MVAr reactor at Robertstown;
- 500/275kV 600MVA transformer at Heywood;
- 275kV 350MVA PST +/-20° at Heywood;
- series capacitors in the Tailem Bend-South East interconnection.

Both of the augmentations in Appendix 4 are entirely overhead line. No undergrounding was considered necessary, although KBR indicated that up to 10km might be required to traverse a segment of the Bookmark Biosphere reserve.

Technical services provided by Alternative 4

The differences between the technical services provided by Alternative 4 and Murraylink are that Alternative 4:

- has only partial control of the power flow over the interconnection depending on generation dispatch and PST tap changing (whereas Murraylink has full control over the power flow);
- cannot provide reactive support to the Victorian/NSW transmission system (whereas Murraylink can);
- injects power into South Australia in the southeast region, so it can only relieve congestion in the Riverlands area if there is no congestion between the southeast region and the Riverlands area (Murraylink injects directly into the Riverlands area, so is not affected by constraints elsewhere in the South Australian transmission system). The transfer of power from Victoria to South Australia by Alternative 4 could also become constrained by other bottlenecks in the South Australian system and by restrictions on the Heywood to South East interconnection, which is susceptible to lightning strikes.

3.4.5 Conclusions on BRW's selection of alternative projects

We agree with BRW's conclusion that generation and demand side management options should not be considered as alternative projects for the purposes of calculating a DORC. Generation and demand side management options are considered in the calculation of the market benefits. The alternative generation options are the merchant entry generators that enter the market in the "without" Murraylink cases; and the demand side management options are the voluntary load reduction options that enter the market as in those cases.

Alternatives 1, 2 and 3 provide technical services that are the same as, or sufficiently close to, those provided by Murraylink to consider them possible alternatives.

On the other hand, the technical services provided by Alternative 4 are significantly different to those provided by Murraylink. The market benefits are also significantly different in that Alternative 4 provides no benefit to the Snowy/NSW or Snowy/Victoria interconnections and does not provide a direct linkage between the South Australian and NSW market regions. Therefore, Alternative 4 does not provide a sufficiently similar level of service as Murraylink to be considered an alternative to Murraylink for purposes of determining a DORC for Murraylink.

3.5 Cost Estimates of Alternative Projects

In order to obtain cost estimates that are directly comparable with the investment in Murraylink, the costs of the alternative projects are estimated subject to the conditions that they are:

- stand-alone projects being built by a new entrant. This means that, compared with projects being built by existing TNSPs, the new project carries the full costs of infrastructure support, administration and spares that could otherwise be spread over a number of projects. It also means that the costs of all spares are included in the capital cost estimates of the new project.
- real projects, so include all the costs that a developer would provide for, including:
  - a budgeted contingency to cover uncertainty in the cost estimates; and
  - expected costs of mitigating environmental impacts. These include the costs which a developer might face to meet environmental restrictions on the project, such as re-routing lines to avoid environmentally sensitive areas and, where this is not possible, tactical undergrounding.

A common operational date of 1 May 2003 is assumed for all projects. It is also assumed that the capabilities of all projects would not be reduced by constraints in other parts of the networks that are interconnected by Murraylink or one of the alternative projects (noting that in consideration of certain findings by PB Associates in their Transfer Capability Review, this assumption might not be strictly correct).

The costs of the alternative projects were estimated by BRW using data sourced from BRW's internal database, other projects and information obtained by BRW from manufacturers and suppliers. The different cost categories that make up the base cost estimates are:

- development works;

- transmission line costs;
- switchyard costs;
- contractors' profit and overheads; and
- interest during construction.

The transmission line and switchyard costs included the cost of spares.

Assumption made in estimating the base costs were:

- Testing and commissioning are 20% of electrical labour hours
- Detailed design costs are 10% of the total switchyard cost not including major plant items
- Project management costs are 10% of total labour costs
- Major plant items are cost turnkey projects incurring a 6% delivery charge
- Switchyard spares are 6% of total switchyard costs
- Profit and overheads were set at 10 percent of the total transmission line and switchyard costs
- Interest during construction was calculated for a five year construction period with a spread of expenditure over that period of 5%, 5%, 40%, 30% 20%.

The base cost estimates of the alternative projects are given in Appendix 5 to the report prepared by BRW as Appendix in support of the Application (BRW Report). Additional information explaining how the cost estimates were made was provided in a BRW letter (BRW's 4 December Letter) prepared in response to questions raised by SEIL.

3.5.1 Alternative 1 - Buronga - Monash 275kV AC o/h line

The base cost estimate for Alternative 1 is given in the following table, which is taken from Appendix 5 of the BRW report[47]. Note that these base costs do not include the additional contingency factor as proposed in the Application. The treatment of the proposed contingency factor is discussed in section 3.5.5 of this Review.

[47] BRW have advised us that total (base) costs are defined as the sum of Total EPC Project costs; Profit and Overheads; Interest during construction; and Total Development Costs.

Table 3.1 Base Cost Estimate of Alternative 1

Base cost estimate of Alternative 1 - 275kV AC o/h line Buronga-Monash	
Item description	**(000$)**
DEVELOPMENT WORKS	
- Project management	2,200
- Feasibility consultants (legal, market, technical, environmental)	1,276
APPROVALS	
- Planning and environment	2,500
- Regulatory – NECA, ACCC, transmission licence	2,293
- Other – easements, licences, financiers, insurance	7,500
TOTAL DEVELOPMENT COSTS	**15,769**
TRANSMISSION LINE WORKS	
- Design	194
- Construction	34,636
- Fabrication	6,767
- Erection	3,929
- Stringing	3,600
- Materials	38,969
TOTAL TRANSMISSION LINE COST	**88,095**
SWITCHYARD WORKS	
- Design	2,152
- Construction (site labour and supervision)	5,320
- Plant	14,855
- Commissioning	557
- Project management	784
- Phase shift transformers (1x275kV 350MVA)	19,080
- Static Var compensators (1x +120/-110MVAr)	19,080
- Transformers (2x275/132kV 160MVA)	6,360
- 132kV connection costs (Monash)	10,400
TOTAL SWITCHYARD COST	**78,588**
TOTAL EPC PROJECT COST	**166,683**
PROFIT AND OVERHEADS (@ 10% OF EPC COST)	16,668
INTEREST DURING CONSTRUCTION	36,373
TOTAL DEVELOPMENT COSTS	15,769
TOTAL	**235,493**

Source – revised from BRW Appendix 5, page 4

Additional information provided in another letter from the BRW (BRW's 5 December Letter[48]) provided a breakdown of line lengths and costs for the overhead line and underground cable. The total line length of Alternative 1 is 210km, of which 180km is overhead line and 30km is underground cable. The costs of each of these were:

[48] BRW letter dated 5 December from Rod Touzel to Jeffery Donahue

- $28.095 million for the overhead line; and
- $60.000 million for the underground cable.

From this additional information, the cost/km estimates for the overhead line and underground cable were calculated, as shown in the table below.

Table 3.2 Cost/km of Cable for Alternative 1

Cost/km of overhead line and underground cable for Alternative 1		
	Overhead line	Underground cable
Length (km)	180	30
Base cost ($ millions)	28.095	60.000
Unit cost ($000/km)	156.1	2,000.0
Profit and ovhdsw (@10%)	15.6	200.0
Total cost/km ($000)	**171.1**	**2,200.0**

3.5.2 Alternative 2 - Monash–Red Cliffs 140kV HVDC o/h line

Appendix 5 of the BRW report gives the base costs estimates for Alternative 2 as:

Table 3.3 Base Cost Estimates of Alternative 2

Base cost estimate of Alternative 2 - 140kV o/h DC line Monash-Red Cliffs	
Item description	**(000$)**
DEVELOPMENT WORKS	
- Project management	2,200
- Feasibility consultants (legal, market, technical, environmental)	1,276
APPROVALS	
- Planning and environment	2,000
- Regulatory – NECA, ACCC, transmission licence	2,293
- Other – easements, licences, financiers, insurance	5,400
TOTAL DEVELOPMENT COSTS	**13,169**
TRANSMISSION LINE WORKS	
- Design	174
- Construction	20,487
- Fabrication	4,702
- Erection	2,730
- Stringing	2,635
- Materials	22,302
TOTAL TRANSMISSION LINE COST	**53,029**
SWITCHYARD WORKS	
- Design	561
- Construction (site labour and supervision)	1,470
- Plant	3,807
- Commissioning	112
- Project management	216
- Transformers (2x350MVA converter transformers)	15,900
- Series caps/DC converter stations	48,720
- 132kV connection costs (Monash)	10,400
TOTAL SWITCHYARD COST	**81,186**
TOTAL EPC PROJECT COST	**134, 215**
PROFIT AND OVERHEADS (@ 10% OF EPC COST)	13,421
INTEREST DURING CONSTRUCTION	29,374
TOTAL DEVELOPMENT COSTS	13,169
TOTAL	**190,179**

Source – revised from BRW Appendix 5, page 4

Further information provided in BRW's 5 December Letter gave the following $/km costs for Alternative 2.

Table 3.4 Cost/km for Cable of Alternative 2

Cost/km for overhead line and underground cable for Alternative 2		
	Overhead line	**Underground cable**
Length (km)	155	25
Base cost ($ millions)	19.679	33.35
Unit cost ($000/km)	127.0	1,334.0
Profit and ovhds (@10%)	12.7	133.4
Total cost/km ($000)	**139.7**	**1467.4**

3.5.3 Alternative 3 – Red Cliffs–Monash 220kV AC o/h line

The base cost estimates from Appendix 5 of the BRW report are given in the table below.

Table 3.5 Base Cost Estimates of Alternative 3

Base cost estimate of Alternative 3 - 140kV o/h DC line Monash-Red Cliffs	
Item description	**(000$)**
DEVELOPMENT WORKS	
- Project management	2,200
- Feasibility consultants (legal, market, technical, environmental)	1,276
APPROVALS	
- Planning and environment	2,000
- Regulatory – NECA, ACCC, transmission licence	2,293
- Other – easements, licences, financiers, insurance	5,800
TOTAL DEVELOPMENT COSTS	**13,569**
TRANSMISSION LINE WORKS	
- Design	174
- Construction	29,074
- Fabrication	5,767
- Erection	3,349
- Stringing	3,100
- Materials	33,184
TOTAL TRANSMISSION LINE COST	**74,647**
SWITCHYARD WORKS	
- Design	1,007
- Construction (site labour and supervision)	2,580
- Plant	6,886
- Commissioning	220
- Project management	379
- Phase shift transformers (1x220/132kV 350 MVA combined transformer/PST)	19,080
- Static Var compensators (1x +120/-110MVAr)	18,020
- 132kV connection costs (Monash)	10,400
TOTAL SWITCHYARD COST	**58,572**
TOTAL EPC PROJECT COST	**133,219**
PROFIT AND OVERHEADS (@ 10% OF EPC COST)	13,321
INTEREST DURING CONSTRUCTION	29,274
TOTAL DEVELOPMENT COSTS	13,569
TOTAL	**189,357**

Source – revised from BRW Appendix 5, page 4

The cost/km estimates provided in BRW's 5 December Letter for the overhead line and underground cable in Alternative 3 are summarized in the table below.

Table 3.6 Cost/km of Cable for Alternative 3

Cost/km of overhead line and underground cable for Alternative 3		
	Overhead line	**Underground cable**
Length (km)	155	25
Base cost ($ millions)	24.647	50.00
Unit cost ($000/km)	159.0	2,000.0
Profit and ovhds (@10%)	15.9	200.0
Total cost/km ($000)	**174.9**	**2,200.0**

3.5.4 Conclusions on the base cost estimates of the alternative projects

There are a number of areas some of the base cost estimate may be higher than would normally be used in calculating the costs of alternative projects for the purposes of determining a DORC, such the level of costs allowed for spares. However, these costs are due to the assumption that the alternative projects are stand-alone projects and their impact on the total base cost estimates is not large.

The underground cable costs are a significant proportion of the total base cost estimates of each of the alternative projects and particularly of the total transmission line costs:

- for Alternative 1, $60 million out of a total line cost of $88 million;
- for Alternative 2, $33 million out of a total line cost of $53 million; and
- for Alternative 3, $50 million out of a total line cost of just under $75 million.

Whereas BRW have reliable and detailed information on the costs of most of the items in each of the alternative projects, BRW advised in its letter that the underground cable costs had been obtained from one supplier who had:

> *"provided a pricing of $1,000,000 per kilometre for supply of cable, and $1,000,000 for installation. As BRW had no reliable internal cost estimates, [the supplier] estimates were used as the base estimate in the quantitative risk assessment, with a cost material variation of –20%/+10% and installation cost variation of –25%/+15%".*

We have not been able to verify the accuracy of these cost estimates. Most of the sources of the costs of laying underground cable appear to be confidential.

However, if we accept the BRW estimate as being in the right range of costs, the high proportion of the total costs made up by the underground cable costs highlights the dependence of the base cost estimates on the recommendations on the extent to which undergrounding is considered necessary. The cost of the alternative projects therefore crucially hinges on the assumptions and conclusions in the KBR report, which recommends a "most likely" amount of undergrounding.

The New Zealand ODV Handbook, for example, states[49]:

> *"if a distribution line consists of underground cables these must be valued as overhead lines of the required capacity unless there is specific evidence that the local authority would not, in normal circumstances, grant consent for overhead reticulation, or that a non-standard contract or a legal obligation requiring the installation of underground lines exists".*

This issue has been recognised by BRW which, in the BRW 4 December Letter, notes that an issue for transmission utilities is that:

> *"if undergrounding is offered rather than being negotiated or mandated through the environmental or statutory approvals process, the transmission network service provider might have difficulty justifying its inclusion and the regulatory value of the asset could be optimised downward in a subsequent regulatory review".*

We believe that stronger justification should be provided for both the need for, and cost of, underground cables for the alternative projects. On basis of the information provided to date and in the absence of Commission guidelines that indicate how the Commission intends to allow for estimated degrees of undergrounding, we consider that a more robust case should be presented for the extent of undergrounding assumed to calculate the alternative project costs.

The effect of the assumptions on the degree of undergrounding on the base cost estimates of the alternative projects can be illustrated by considering the three alternative projects which included tactical undergrounding without any undergrounding.

As a first approximation, we have assumed that the development costs are unchanged, although it is quite likely that the costs of obtaining planning and environmental approvals would be significantly higher without undergrounding.

We have reduced the transmission line costs by removing the underground cables and replacing them with overhead lines of the same unit (per km) cost as the other overhead lines in the project. Reduced the transmission line costs results in corresponding reductions in profit and

[49] On page 70 of the ODV Handbook in the section dealing with Optimisation of Elements in the System, Transmission/subtransmission lines and cables, Overhead/underground transmission

overheads (which are 10% of the total transmission line and switchyard costs) and interest during construction[50]. The costs of the alternative projects, with and without undergrounding, are shown in Table 3.7

Table 3.7 Comparison of alternative base project costs with and without undergrounding

Alternative (Base) Project Costs with and without undergrounding (000 $)						
	Alternative 1		Alternative 2		Alternative 3	
	with	without	with	without	with	without
Development costs	15,769		13,169		13,569	
Transmission line costs	88,095	35,973	53,029	25,146	74,647	31,482
Switchyard costs	78,588		81,186		58,572	
Total EPC project cost	166,683	114,561	134,215	106,332	133,219	90,054
Profit & ovhhds (10%)	16,668	11,456	13,422	10,633	13,322	9,005
Interest during construction	36,373	26,628	29,374	24,440	29,274	21,152
TOTAL	**235,493**	**168,415**	**190,180**	**157,174**	**189,384**	**135,981**
Difference		**-68,102**		**-36,432**		**-56,399**

As noted previously the development costs, which include the costs of obtaining planning and environmental approvals, would most likely be significantly greater without tactical undergrounding. The above table shows that, if it were possible to construct the alternative projects without undergrounding, the developer could afford to spend considerably more on obtaining planning and environmental approvals before negating the savings in transmission line costs.

3.5.5 Contingency and treatment of risk

Under the ODV methodology, the basis for determining the ORC would normally be the base cost estimate where that base estimate has been derived from the actual costs of similar projects. Therefore, where the alternatives projects are similar to actual projects have recently been completed, the base cost estimates should be reasonably representative of the actual costs of alternative projects.

Where few (or no) similar projects have been constructed, or the circumstances under which the projects are to be constructed have changed, allowance needs to be made for the uncertainty in the base cost data.

BRW has calculated a contingency allowance that takes cost uncertainty into account by:

[50] Although we could not reproduce exactly the interest during construction (IDC) calculated by BRW in the "with" undergrounding cases, we used the same expenditure profiles as assumed by BRW and obtained very slightly higher IDC costs.

- identifying the key project risks through a brainstorming exercise with a team of experts; and
- quantifying those risks by asking project representatives to assess a "most likely" (P50) value, a "least likely minimum"value (P10), which is the value for which there is only 10% probability that the outcome will be below this value, and a "least likely maximum" value (P90), which is the value for which there is only 10% probability that the outcome will be above this value.

The P10 and P90 values are expressed as percentages of the most likely value. For example, for activities with a relatively low uncertainty, P10 value is 95% of the most likely value, and the P90 value 105% of the P50 value. For other activities which are subject to a greater degree of uncertainty the differences between P10, P50 and P90 values are greater. For example, for underground cable installation P10 is 75%, and P90 115%, of the P50 value.

The contingency allowance was calculated for each of the alternative projects using @Risk in Excel, a spreadsheet model that analyses the probability of the base cost estimate being too low or too high assuming a a triangular probability distribution with the three points at P10, P50 and P90. The results from the @Risk model are compared in the following table.

Table 3.8 Cost Estimate Comparison

(000$)	Alternative 1	Alternative 2	Alternative 3
P10	230,080	181,614	187,170
Base estimate	235,493	190,179	189,357
P30	236,196	190,103	192,822
P40	238,383	193,674	194,678
Mean cost	240,437	197,550	196,537
P50	240,415	196,854	196,271
P60	242,468	200,455	198,192
P75*	245,906	206,308	201,608
P90	250,882	214,957	205,854

* BRW's proposed regulatory cost of alternatives – including the contingency factor

The table shows an almost-symmetric distribution of probable costs, with P50 being very close to the mean. The base estimate is close to P30, which indicates the BRW considers that there is around a 70 percent probability that it will be exceeded. BRW recommends that the P75 cost be used as the regulatory cost of the alternative projects.

However, it is our view that the P75 cost estimate is an overly conservative basis for valuation. Although with any single project, a developer will incur an actual cost that might not even fall within the range bounded by the P10 and P90 values, over many projects the actual costs are will tend, on average, to the P50 value. We consider the P50 value to be more appropriate for the setting of ORC values, which are intended to be typical costs of particular categories of assets and are not related to any specific project.

We therefore consider that an appropriate opening valuation of Murraylink should be based on the P50 cost estimates of the alternative projects. We believe that the "most likely" cost estimate is more in keeping with the intent of the ORC methodology than the alternative proposed by BRW, which is that a developer would budget on the P75 estimate.

4 COMMENTS ON THE APPROPRIATENESS OF THE OPENING ASSET VALUATION

The setting of a regulatory asset value for Murraylink serves two primary roles in regard to the conversion of a network service to a prescribed service:

1) as a parameter in application of the regulatory test; and

2) as the basis for which maximum allowable revenues are to be computed.

The natural starting place in which to consider these dual issues is the Code. However, the Code provides only general guidance in regard to the process of conversion to prescribed status. Indeed, the Commission has noted that[51]:

> *Clause 2.5.2(c) sets out an arrangement where the relevant regulator has a high degree of discretion regarding the classification of a network service as a prescribed service and determining the appropriate extent that a revenue cap or price cap is adjusted to reflect the newly prescribed services.*

The Commission does draw a connection to the regulatory test (albeit in a slightly different context) in that:

> *the process of changing status of network services requires the NSP to submit to a valuation process that delivers outcomes consistent with the intent of the regulatory test.*

Making reference to the material cited above, MTC has provided in its Application a methodology which aims to apply the Commission's Draft Regulatory Principles to the calculation of Murraylink's regulatory asset valuation, and which enables Murraylink to satisfy the regulatory test.

More specifically, in its Application MTC has proposed a means in which a *regulatory asset value* could be computed. As stated in section 4.0 of their Application:

> *this analysis provides the Commission with the basis upon which the Commission can determine:*
>
> - *that the network service provided by Murraylink may be classified as a prescribed service; and*
> - *the maximum allowable revenue that may be recovered by MTP.*

In the following sections, we describe the methodology proposed by MTC, and evaluate that methodology in regard to application to the regulatory

[51] ACCC Applications for Authorisation: Amendments to the National Electricity Code: Network pricing and market network service providers. Page 138. September 2001

test. We then consider the linkage between asset valuation for the purpose of the regulatory test and as the basis for setting the maximum allowable revenue that may be recovered by MTP. Finally, we consider some key aspects of that methodology when used as the basis for the setting of the maximum allowable revenue to MTP.

4.1 MTC's Asset Valuation Methodology for the Purpose of the Regulatory Test

In section 4.4.6 of MTC's Application, the regulatory asset value (RAV) of an interconnector is defined as equal to its regulatory cost (RC) less the net present value of its operating and maintenance (O&M) costs, or simply restated as:

RAV = RC – O&M

MTC provide**s** a summary of the conditions under which it proposes that an interconnector would satisfy the regulatory test, where

> *"its regulatory cost must be the less than or equal to, the lesser of:*
>
> - *the value of the gross market benefits the interconnector provides,*
> - *the full life-cycle cost of the lowest cost alternative project, and*
> - *the estimated life-cycle cost of the existing interconnector itself."*
>
> *(Section 4.4.5 MTP Application)*

MTC have thus defined a set of conditions whereby the regulatory cost of the interconnector is defined as providing a positive (or potentially zero) net market benefit that is equal to or greater than any of the net market benefits provided by the alternative projects considered, as well as the actual cost of the interconnector itself.

The proposed methodology appears to be consistent with the regulatory test in that it provides conditions under which:

- the *regulated cost* of Murraylink must be less than or equal to estimated market benefits; the costs of alternatives considered; and the actual cost of Murraylink.

Alternatively, the methodology appears to be robust to the ex-ante appraisal of alternative proposed projects as they would satisfy the conditions if:

- the full life-cycle cost of that alternative project is less than or equal to both its estimated market benefits and the cost of alternatives.

Estimates of relative costs of Murraylink, the alternatives considered, and the value of gross market benefits which have been provided by MTC and their consultants are provided below.[52]

Table 4.1 Ranking of comparators to determine "regulatory cost" as defined by MTC*.

Comparator	Source	NPV of life-cycle costs
Murraylink	MTC**	Greater than $214.2m
Alternative 1	BRW***	$285.8m
Alternative 2	BRW	$244m
Alternative 3	BRW	$240.4m
Alternative 4	BRW	$241.9m
Gross Market Benefits	TEUS****	$214.2m

* Alternatives 1-4 include estimated base costs; contingency cost; and life-cycle O&M costs as provided by BRW

** MTC Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12. Sec. 4.9.

*** Appendix F: Report – Selection and Assessment of Alternative Projects – Burns and Roe Worley. Page 22

**** Appendix D: Report – Report on the Estimation of Murraylink Market Benefits – TransEnergie US Ltd. Page 34

Given the estimated values as proposed by MTC, the proposed regulated asset value of Murraylink is set at the estimated net market benefit:

Regulatory asset value		Gross market benefit		NPV of O&M
$176.906 million	=	$214.240 million	-	$37.334 million

As proposed by MTC, the *regulatory cost* is equal to the gross market benefits the interconnector provides, which have an estimated value of $214.240 million as proposed in this Application. The net present value of O&M costs are estimated at $37.334 million.

Thus the regulatory asset value proposed is an *economic value*, as the full-cycle cost of the lowest cost alternative and the (actual) cost of Murraylink itself are greater than the gross market benefits of the proposed interconnector. In this case, the regulatory value is not based on either actual costs or the cost of equivalent assets, although these two factors do act as constraints (ceilings) to the regulatory asset value. As a corollary - as the lesser of the specified comparators - there is a value for the regulatory

[52] Noting that we have some concern over the estimated costs of alternatives, which were set out in Section 3 of this Review.

cost which by definition just passes the regulatory test as long as its gross market benefits are greater than the net present value of O&M costs.

As noted above, the key conditions to be met here are in regard to the actual cost of Murraylink and the full life-cycle costs of the lowest cost alternative considered. These conditions, along with the estimated value of market benefits provide a ceiling on the value of the regulatory cost under which the regulatory test would be satisfied under MTC's proposed approach. In light of this, it is useful to consider a few points:

- We have not been provided Murraylink's actual cost data, and accept as given the statement of MTC (section 4.9) that the estimated regulatory asset value is less than the actual cost of Murraylink.

- The estimated regulatory cost is less than the full life-cycle costs of alternative projects as assessed by BRW. These estimates have been given further consideration by us in section 3 of this Review. For the purpose of assessing the asset valuation *methodology* used by MTC in this section of our Review, we have reviewed and commented on the assessments provided by BRW.

- The value of the gross market benefits as estimated by TEUS. (Appendix D) has been assessed by us in section 2 of this Review, and for the purpose of discussion, is taken as given for this section on valuation methodology.

We consider the potential *sensitivity* of outcomes to these variables in the following sections.

4.1.1 Valuing a sunk cost for the purpose of the regulatory test

MTP's application for conversion to a prescribed service provides a number of unique features which have not been previously considered within the context of the regulatory test. A primary feature in regard to asset value, cost of construction, and net benefit is that Murraylink has already been commissioned, and is reasonably considered a "sunk cost[53].

The Commission has addressed the matter of sunk costs within the more general treatment of regulation of transmission revenues[54].

In determining an appropriate asset valuation methodology economic principles and analysis do not provide an unambiguous

[53] Noting that section 6.2.3(iv) of the Code has a very specific definition for "sunk assets" which varies from the use of the term here, whereby only assets in existence and generally in service on 1 July 1999 are set in this category. We will try to be clear in our use of the related terms in each instance where we use them this document. The reference below on "existing sunk assets" is presumably in regard to the generic definition – not that as provided for in section 6.2.3(iv) of the Code.

[54] ACCC Draft Statement of Principles for the Regulation of Transmission Revenues. Page 39. 27 May, 1999.

> *decision rule for the valuation of existing sunk assets. Rather economic principles provide lower and upper bounds – scrap value and replacement cost. Within these bounds there is opportunity for regulatory judgement.*

A key issue here is the context in which asset value is to be considered within the regulatory test. While there are still a number of issues to be resolved in application of the regulatory test,[55] the Commission has stated that it "has relied on the principles associated with cost/benefit analysis" in its development.

Within the cost/benefit framework underpinning the regulatory test, it seems reasonable to account for economic costs in the manner in which MTP has proposed. Where a project has already been built, costs relevant to the efficient allocation of resources include future O&M costs, and any required augmentations which would be required to support the service potential underlying the estimated value of market benefits stemming from the project. It is these costs which represent the relevant benchmark against which benefits should be compared. We also note that in view of the sunk nature of the investment, the cost of alternative projects does not seem to us to be particularly relevant in regard to passing the regulatory test[56].

Intuitively speaking, there must be a value for which the asset which passes the regulatory test, unless a costless alternative technology is discovered (after adjusting for relative future O&M costs). This is certainly the case in a static sense[57], where the resource allocation process has already taken place, and is largely irreversible[58].

Alternatively, for an *ex ante* assessment of a proposed project, the estimated asset value (which in practice would likely be associated with construction cost) plays a key role in allocating resources as primary parameter underlying a cost/benefit analysis.

4.1.2 Robustness test and impact of error in estimation

The dual issues of robustness and impact of error are relevant to the consideration of the appropriateness of the opening asset valuation submitted by MTC. As an unobservable variable, MTC's regulated asset value is subject to error in estimation. It would seem prudent to consider the robustness of the outcomes under the regulatory test to the setting of this estimated value. The second issue to consider is the ultimate impact, or materiality, of such error.

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[55] Noting that the Commission has raised some 34 issues to be addressed in its Review of the Regulatory Test, May 2002.

[56] Further noting that the costs of alternative projects may play a crucial role in setting the regulatory asset value for the purpose of revenue recovery.

[57] The case of dynamic efficiency and incentives is discussed in a later section which considers the asset valuation methodology in regard to revenue recovery, which is where we believe such issues are best considered.

[58] Noting that there may be salvage value in certain components comprising Murraylink. We have not been provided any estimates of this value, however.

As a means by which to allocate resources, the regulatory test typically relies on comparison of the costs of a proposed project and the benefits anticipated from its use of its services. When the test is employed on an *ex ante* basis, accurate estimation of both costs and benefits is crucial to the effective use of the test. For example, if estimated costs or benefits diverged from the true relevant parameters in a way that erroneously suggested approval of the project, investment would be made which should not have been undertaken. The converse holds true as well, as there would be a net economic loss from forgoing investment where the *true* values of the underlying parameters suggest approval of a project, but error in estimation leads to rejection of the proposal.

In such a case, the estimated net gains – which we will call *headroom* - should be reasonably robust to potential error in the estimation of the underlying parameters of cost and benefit. Put another way, *headroom* should be sufficiently "large" in regard to the underlying variance of the estimated parameters – where large might be defined within a probabilistic or scenario based framework[59].

Alternatively, in an *ex post* analysis, the role of the estimated parameter (market benefit) is in certain cases largely irrelevant. Resources have already been sunk, and the proxy no longer plays the vital role in resource allocation as it does where the project is still to be constructed. The proxy is not entirely irrelevant, though, as there are future costs associated with ongoing O&M, (broadly defined) which do require consideration against the estimated market benefit of that project. The key issue here is that the headroom between estimated market benefits and estimated life-cycle costs of O&M is likely to be rather large in relative terms, making the results of the test largely insensitive to error in estimation of the market benefits parameter[60].

While the quantitative analysis referred to above is beyond the scope of our work, we provide a simple calculation of *headroom* implied for Murraylink to place some empirical context to the matter. We also point out that several sensitivities have been computed by TEUS – none of which appear to materially change the qualitative result in regard to Murraylink.

[59] One might also consider a "loss function" if it was thought that there was an asymmetry in the loss stemming from Type 1 or Type 2 errors.

[60] More accurately put – the variance of the estimated parameters may be "small" in terms of a confidence interval about the underlying estimated parameters, which in this case would be the NPV of market benefits and NPV life-cycle costs of O&M.

Table 4.2 "Headroom" implied by MTC analysis of net benefits.

Project	Estimated regulatory asset value*	Estimated future cost**	Headroom
Murraylink	$176.906 million	$37.334 million	$139.572 million

* As the lesser of the proposed comparators, the regulatory asset value is by definition identical to the estimated value of market benefits under MTC's approach.

** Estimated future cost for Murraylink refers to the NPV of life-cycle O&M.

The implied headroom in this case is $139.572 million

4.1.3 Conclusions on MTC's asset valuation for the purpose of the Regulatory Test

- In consideration of sunk costs, economic values such as the regulated asset value proposed by MTC provide a sound basis for assessment within the context of efficient resource allocation. As an economic value, the asset valuation methodology proposed by MTC appears to be appropriate for use in regard to the regulatory test.

- The estimated value of market benefits - which is the basis for setting of the regulatory asset value - is subject to estimation error. Nevertheless, we have not been provided any information which would clearly suggest to us that such error would have a material impact on the qualitative conclusions of the regulatory test as applied by MTC – noting that we have not undertaken a comprehensive analysis of this matter. Such analysis would, in our opinion, be useful.

4.2 Linkage between the Regulatory Test and Regulatory Asset Base

As we noted in the introduction to this section of our Review, the setting of an asset value for Murraylink serves two primary roles in regard to the conversion of a network service to a prescribed service; as a parameter in the application of the regulatory test; and as the basis for which maximum allowable revenues are to be computed. MTC has proposed a very direct and lock-step relationship for asset valuation as applied to these two related purposes. We summarise their proposal as follows.

First, MTC has provided an interpretation of the regulatory test in section 4.2 of their Application, in which it draws out what it sees as an implicit expectation that:

> *if a proposed new interconnector satisfies the Regulatory Test, then the capital costs of the new interconnector (estimated for the*

> *purpose of the Regulatory Test) may be added to the value of the regulatory asset base of the proponent TNSP.*

While this is a matter for the Commission to decide, we would further note the basis of ODV, in which optimised costs and economic values are to be given consideration as well.

Furthermore, MTC proposes an important corollary to this point.

> *Conversely, MTP has an expectation that if it proposes a regulatory asset value at which Murraylink satisfies the Regulatory Test, the Commission will:*
>
> - *Determine that the network service being provided by Murraylink should be a prescribed network service; and*
>
> - *Allow MTP to incorporate Murraylink into its regulatory asset base at that regulatory asset value.*

While we see some merit in the broad principle here, we wish to point out two fundamental factors in regard to the application of this principle to the case at hand.

1) We find precedents which would support the use of an *economic value* for the asset base in terms of both the regulatory test and for the purpose of revenue recovery (as incorporated into the regulatory asset base), where we interpret the MTC approach to asset valuation as an economic value approach - broadly defined.

2) As an unobservable variable, MTC's regulated asset value (as defined by the estimated value of market benefits) is subject to estimation error. As a *ceiling in regard to the regulatory test*, it may well be that the outcome of the test (as put forward by MTC) is robust to such error – particularly keeping in mind that much of the costs of Murraylink are sunk. However, as a key variable in the *setting of maximum allowable revenue*, such error may be material to the outcome.

Following on with the points raised above, we next consider the appropriateness of the opening asset valuation submitted by MTC in regard to its use *in setting the regulatory asset base.*

4.3 MTC's Asset Valuation Methodology for the Purpose of the Setting the Regulatory Asset Base

As noted previously, MTC has provided an opening asset value which they believe provides both a proxy for application of the regulatory test, and setting the maximum allowable revenue that may be recovered by MTP.

At the time of writing this Review, we find little guidance from the Code in regard to how one is to establish an opening asset value within the context of the provisions for conversion of a market network service to that of a prescribed service, other than:

> *If an existing network service ceases to be classified as a market network service it may at the discretion of the Regulator or Jurisdictional Regulator (whichever is relevant) be determined to be a prescribed service or prescribed distribution service in which case the revenue cap or price cap of the relevant Network Service Provider may be adjusted in accordance with chapter 6 to include to an appropriate extent the relevant elements which provided those network services.*
>
> *Clause 2.5.2(c)*

Section 6.2.3 of the Code provides general principles under which TNSPs are to be regulated, but limits more specific directives to the specific cases of "sunk assets" and revaluation of "new assets"[61] – neither of which (to our understanding) explicitly include the case at hand.[62]

In regard to *revaluation* of "new assets" (noting that it is our understanding that this does not strictly apply to the case at hand, and is provided as background only) the Code states that:

> *in determining the basis for asset valuation to be used, the ACCC must have regard to:*
>
> *the agreement of the Council of Australian Governments of 19 August 1994, that the deprival value should be the preferred approach to the valuing of network assets*
>
> *(section 6.2.3(4)(iv)A)*

The use of deprival value is further highlighted by the Commission in a more general discussion of the matter in section 4.3 of its Draft Regulatory Principles, which appears to make reference to the clause cited above. In the next section we discuss deprival value techniques, and consider whether MTC's approach could be seen as being broadly consistent with deprival value.

4.3.1 Optimised deprival value

Optimised Deprival Value (ODV) has been applied across a number of regulated industries and jurisdictions. This methodology was initially developed in New Zealand in a report by Oxford Economic Research Associates and Ernst & Young in 1990, and has since been extensively utilised there, where the method has been codified and uniform standards

[61] With the meaning of these terms as provided for in section 6.2.3(d)(4)(iii) and (iv) of the Code.

[62] We wish to be clear that this is not a statement of opinion – simply our understanding of the matter.

of application have been set under which lines companies provide publicly available ODV valuations.

The New Zealand ODV Handbook[63] describes the aim of applying the methodology:

> *is to value the assets at the level at which they can be commercially sustained in the long term, and no more. The resulting value should be equal to the loss to the owners if they were deprived of the assets and then took action to minimise their loss.*

The Handbook further defines ODV as "the minimum of Optimised Depreciated Replacement Costs (ODRC) and Economic Value (EV). The ODRC is the replacement cost of the existing system fixed assets at Modern Equivalent Asset (MEA) value, which have been optimised from an engineering standpoint and depreciated according to their age."

EV is succinctly defined in a more recent New Zealand Commerce Commission Discussion Paper on asset valuation[64] as "the greater of disposal or salvage value (i.e. net realisable value), or its value to users…".

For practical purposes, the Commission has focused more directly on the DORC approach to valuing transmission assets. This is due primarily to the well-understood problem of "circularity" which is common among certain regulatory pricing regimes, in that future benefits are often directly related to the regulated revenue stream, which in turn is dependent on the regulated asset value.[65]

The asset valuation approach proposed by MTC is unique in the Australian market,[66] in that it does allow for the potential to break the circularity of regulatory pricing and ODV (specifically the use of EV), and employ ODV in regard to setting of the regulatory asset base.

Of course, even where EV is used, DORC still has the effect of setting a ceiling on the valuation of an asset. This is relevant to the case at hand, in that even though MTC's regulatory asset base is the lesser of the comparators (as estimated by MTC), those comparators would set a ceiling on regulatory asset value.

In its Draft Statement of Principles for the Regulation of Transmission Revenues, the Commission has set out what it considers a standard approach for valuation of transmission assets on the basis of DORC, comprising three steps:

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[63] Ministry of Economic Development, Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses. Fourth Edition. October 2000.

[64] New Zealand Commerce Commission, Review of Asset Valuation Methodology: Electricity Lines Business' System Fixed Costs. Discussion Paper, Oct 2002.

[65] See, for example, the discussion in the Commission's Draft Statement of Principles for the Regulation of Transmission Revenues. Section 4.3.

[66] The primary use of ODV in New Zealand has been to value "sunk cost" assets, for which the actual costs were largely unrecorded and have now become irrelevant

- "Optimisation – determine the optimal configuration and sizing of transmission assets;
- Replacement costs – a modern engineering equivalent (MEE) is established for each asset in the optimised system and a standard replacement cost (SRC) established; and
- Depreciate those assets (usually straight line) using the standard economic life (SEL) of each asset together with an estimate of the remaining life (RL) of each asset. …"

An important consideration here is the way in which the optimisation procedure is to be undertaken. While further clarification of the matter by the Commission is anticipated, the Draft Statement of Principles (page 43) does describe the importance of a "top down" approach, which considers infrastructure from a system-wide perspective which can:

> *more readily accommodate the impact of new or alternative technologies. For example, an optimal solution may do away with existing types of infrastructure and may involve a totally different transport mechanism or product to satisfy associated final demand in end markets. Such solution may only be apparent when the customer base and services provided are considered in the broadest possible perspective.*

The issue of optimisation - particularly with regard to the scope of alternatives - is a matter of ongoing debate. While we do not wish to imply that material cited above provides firm or final direction in regard to the matter, it does provide a starting basis in which to frame the problem, and to consider the way in which MTC has operationalised an asset valuation methodology.

4.3.2 The MTC approach to asset valuation as an ODV

MTC propose that the regulatory asset value be set at the lesser of market benefits and the cost of the lowest cost alternative project (after adjusting for O&M costs). This seems to us broadly consistent with the definition of ODV. There are, however, two key points we wish to raise.

1) The regulatory test defines market benefit as "the total net benefits of the proposed augmentation to all those who produce, distribute and consume electricity in the National Electricity Market." That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent rankings of options in most (although not all) credible scenarios." From an economic perspective, we see this as broadly consistent – at least in theory – with the definition of EV provided above[67].

[67] A caveat here is that not only are equivalent rankings essential, so are absolute levels. However, we find it unlikely that one would likely obtain without the other, as most comparators are in the same metric as standard cost/benefit parameters, leading to a consistent normalisation between the two.

2) MTC has considered alternatives which were "designed to provide the same services as Murraylink."[68] We are not aware of any formal treatment by MTC in regard to *optimisation*, which would normally be associated with an ODV/DORC value.

In placing the MTC approach to valuation within the context of ODV framework, we would make one further point. The potential link between ODV and MTC's approach is an analytical construct of ours, and is potentially neither necessary nor sufficient in regard to their Application. Nevertheless, we have attempted to draw this link in order to put a conceptual framework around the matter of whether the asset valuation provided by MTC is appropriate for the purpose of setting an opening asset value.

In light of the Commission's ongoing refinement of asset valuation guidelines, we have considered the MTC approach against what we see as an obvious standard as gleaned from relevant reference points. Within this context, the approach taken by MTC appears to us to have some merit – at least at the conceptual level – as a basis for the setting of the opening asset value.

We do, however, have some concerns in regard to the *practical application* of the approach in terms of robustness and the impact of error in estimation of market benefits as a proxy for EV – thus asset value. These matters are discussed below.

4.3.3 Robustness test and impact of error in estimation

In Section 4.1.2 of our Review, we put forward the case under which, as a sunk cost, the value ascribed to Murraylink may be unlikely to have a material impact on resource allocation – a key factor underlying the regulatory test. More specifically, MTC's asset valuation - *for the purpose of the regulatory test* - seems likely to be robust to reasonable assumptions and uncertainties underlying unobservable variables.

However, we see the case as rather different in regard to the setting of an opening asset base providing the basis the maximum allowable revenue to be recovered by MTP. As described in section 2 of this Review, a number of key empirical and methodological assumptions exist which have a direct and material impact on the estimated value of market benefits. While the assumptions and methodology employed by MTC and their consultants does, in our view, fit within the bounds of precedents set within the context of the regulatory test, it is another matter when applied as an opening asset value.

While it would be overly cumbersome to re-list the findings presented in section 2 of this Review, a summary of the key factors making up market

[68] Appendix F MTC Application, page II of the Executive Summary.

benefits, and key sensitivities are shown below as an illustration of the point we wish to make.

Table 4.3 Summary: Base Case Gross Market Benefits

Factor	NPV of gross market benefits*	Key sensitivities (illustrative only – not comprehensive)
Energy savings	\$79.2 million	• SRMC of energy production • Indexing • Demand • Generation entry (type and size)
Capacity deferral	\$51.9 million	• Demand • Entry of new plant • O&M costs
Reliability	\$58.0 million	• Demand • Level of VoLL (indexing) • Entry of "reliability plant"
Riverland deferral	\$25.0 million	• Timing and requirements of deferral • Augmentation developments • O&M costs
Total gross benefits	\$214.2 million	• All of the above; and • Assumptions on long run equilibrium / length of benefits stream • Discount factor

* Calculation of NPV by key segments sourced from Appendix E of the Application: CRA Assessment of Murraylink Market Benefits, page 23.

For the purpose of asset valuation, the overall *impact* of this sensitivity, or error in estimation, can be considered in a static and dynamic environment:

In a static environment – where as a sunk cost, error in estimation (thus setting of maximum allowable revenue) would not necessarily influence investment choices or the efficient allocation of resources, but would lead to either a greater or lesser transfer of revenue to MTP than would be the case where the value of the asset was directly observable. This would be the case in biased or unbiased error processes. The matter is one of equity, not efficiency.

In a dynamic environment – there could be an incentive on the part of a proponent to utilise their advantage stemming from an asymmetry in information regarding underlying costs to "game" the conversion process.

For example, a proponent might initially develop a project under the anticipation that conversion to a prescribed service might be approved at an asset value greater than the cost of the original investment. This could have implications in regard to efficient allocation of resources, as well as equity considerations.

In making the above statements, we wish to be clear that we have no reason to suspect any such gaming behaviour on the part of the Applicant, nor have we undertaken any formal analysis to determine nature of the error process underlying the estimates provided by MTC.

4.3.4 Conclusions on the asset valuation in regard to setting the opening asset base

- Given the potential for error in the estimation of net market benefits, the sensitivity of this variable to key assumptions, and the impact that this error could have on the setting of the maximum allowable revenue, we think it prudent to undertake a more comprehensive assessment of the setting of the regulatory asset value, with attention given to the summary measures used to "build up" the value of market benefits - thus the regulatory asset value.[69]

- In doing so, it would be useful to refine the framework for estimation of market benefits, including the setting of key parameters underlying the estimation of market benefits.

- We see the ODV approach as offering a robust framework in which to place the setting of the opening asset base – which we view as amenable to the approach proposed by MTC.

[69] This statement is made without prejudice to the modelling carried out in support of the Application.

5 SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

In this Review we have considered:

- the methodology, assumptions and findings of TEUS in their assessment of the market benefits associated with Murraylink;
- the appropriateness of the alternative projects selected by BRW and the costs associated with those alternatives; and
- the appropriateness of the opening asset valuation submitted by MTC in line with the regulatory test.

A summary of our conclusions and recommendations are provided below.

5.1 Assessment of Market Benefits

5.1.1 Methodology

The methodology employed by TEUS in estimation of market benefits appears to us as broadly consistent with guidelines as set out under the regulatory test, and in application of the test in recent studies referenced by TEUS and reviewed by us.

Most of the primary *components* comprising market benefits are consistent with those identified in comparable analysis undertaken for the SNI and SNOVIC interconnection.

While there are certain technical aspects underlying the methodology chosen by TEUS to estimate market benefits which do diverge from comparable studies, we do not find such divergence as clearly unreasonable. In most cases where there is a divergence in methodology, the treatment has been reasonably transparent, although in certain cases more detailed assessment may be warranted given the technical complexity of the matters considered here, again noting that we have not undertaken an audit of the models employed for this assessment of market benefits.

The way in which TEUS has modelled merchant generation entry (in the "with" and "without" Murraylink scenarios) is a case in point, where the conceptual framework for analysis appears to us as appropriate, but further review of the detailed modelling techniques, assumptions and outcomes is warranted, as the value of generation deferral is a key component of the overall estimate of market benefits.

We are generally comfortable with the choice of modelling tools employed by TEUS in their assessment of market benefits *in terms of the practical alternatives available,* but note that the findings provided are sensitive to a number of features underlying those models, and that they are subject to error in estimation. This is a matter common to similar market benefit studies carried out estimation of market benefits, where proxies are defined for unobservable variables, and simulation models are employed to form forward projections of stochastic variables.

5.1.2 Key Assumptions and Findings

In general, we find that many of the key assumptions employed by TEUS are broadly consistent with those of other recent studies which have estimated market benefits under the regulatory test.

Where TEUS has employed a set of assumptions which vary from comparable studies, they have been reasonably transparent considering the difficulty of articulating such matters. While there may be room for professional debate on the specific setting of certain assumptions, we do not generally find the TEUS' assumptions to be clearly in-appropriate.

However, one must recognize that there are a number of key assumptions which will have a direct and material impact on the estimated value of market benefits. We have discussed in detail some of these factors, and highlighted a set of those under which the estimate of market benefits is highly sensitive.

This matter becomes significant within the context of the MTC Application, where the estimated value of market benefits provides the basis for the setting of the maximum allowable revenue which MTP would be allowed to recover from transmission customers[70]. With this in mind, we believe a more rigorous, and perhaps prescriptive analysis of the underlying assumptions is warranted.

Given the importance of the findings provided by TEUS (that is, the estimated value of market benefits) we recommend that further assessment be carried out[71]. This would include review of areas such as:

- the modelling procedures employed by TEUS;
- raw data inputs to the models;
- key data outputs;
- calculations of final summary measures used to "build up" the value of market benefits; and
- "stress test" of the model outputs to better determine the sensitivity of results to key inputs.

We believe particular attention is warranted in regard to the modelling technique applied in estimation of merchant generation entry, in which further analysis should be undertaken to more clearly assess its robustness

[70] This issue is discussed in more detail in section 4 of our Review.

[71] This statement is made without prejudice to the modelling carried out in support of the Application.

to a well defined set of key assumptions. The aim here is to obtain a robust estimate of the value of generation deferrals.

5.2 Appropriateness of Alternative Projects

5.2.1 Choice of Alternatives

BRW has provided four alternatives which are intended to provide the same level of services as Murraylink, as well as giving brief consideration to a generation option and demand side management. Alternatives 1, 2 and 3 provided by BRW are broadly consistent with an appropriate choice of alternatives for determining the DORC of Murraylink in that they provide similar technical services, but do not provide higher level of services[72].

On the other hand, the technical services provided by Alternative 4 appear to us as significantly different to those provided by Murraylink. The market benefits are also significantly different in that Alternative 4 provides no benefit to the Snowy/NSW or Snowy/Victoria interconnections, and does not provide a direct linkage between the South Australian and NSW market regions. Therefore, Alternative 4 does not provide a sufficiently similar level of service as Murraylink to be considered an alternative to Murraylink for purposes of determining a DORC for Murraylink. We also agree with BRW that the generation option considered and Demand Side Management do not provide a similar level of service within the framework considered here.

5.2.2 Costs of Alternatives

There are a number of areas where some of the base cost estimate may be higher than would normally be used in calculating the costs of alternative projects for the purposes of determining a DORC, such the level of costs allowed for spares. However, these costs are due to the assumption that the alternative projects are stand-alone projects and their impact on the total base cost estimates is not large.

The underground cable costs are a significant proportion of the total base cost estimates of each of the alternative projects and particularly of the total transmission line costs:

- for Alternative 1, $60 million out of a total line cost of $88 million;
- for Alternative 2, $33 million out of a total line cost of $53 million; and
- for Alternative 3, $50 million out of a total line cost of just under $75 million.

[72] The latter condition is usually applied to ensure that asset values are not inflated by choosing modern equivalent assets that provide a higher level of service (at a higher cost).

The proportion of costs made up by the underground cable costs highlights the dependence of the base cost estimates on the recommendations on the extent to which undergrounding is considered necessary. The New Zealand ODV Handbook, for example, states that "if a distribution line consists of underground cables these must be valued as overhead lines of the required capacity unless there is specific evidence that the local authority would not, in normal circumstances, grant consent for overhead reticulation, or that a non-standard contract or a legal obligation requiring the installation of underground lines exists".

We believe that stronger justification should be provided for both the need for, and cost of, underground cables for the alternative projects. On basis of the information provided to date, we do not consider that a sufficiently robust case has been made for the extent of undergrounding for it to be used to determine a DORC value.

In addition to the base cost estimates, BRW has added an allowance for contingency. A contingency was calculated for each of the alternative projects using @Risk in Excel, a spreadsheet model that analysed the probability of the base cost estimate being too low or too high.

BRW recommends that the P75 cost be used as the replacement cost of the alternative projects. We consider that the P75 cost estimate is an overly conservative basis for valuation. While the general approach taken by BRW has merit, we believe that the P50 cost is more in keeping with the ORC methodology which is aimed at setting a typical cost for particular categories of assets. We believe that further consideration be given to the specification of the contingency framework especially if the DORC methodology is to be more widely applied in the NEM.

5.3 Appropriateness of Asset Valuation

We find precedents which would support the use of an *economic value* for the asset base in terms of both the regulatory test; and for the purpose of revenue recovery (as incorporated into the regulatory asset base) where we interpret the MTC approach to asset valuation as an economic value approach - consistent with ODV techniques

As an unobservable variable, MTC's regulated asset value (as defined by the estimated value of market benefits) is subject to estimation error. As a *ceiling in regard to the regulatory test*, it may be that the outcome of the test (as put forward by MTC) is robust to such error – particularly keeping in mind that much of the costs of Murraylink are sunk.

However, as a key variable in the *setting of maximum allowable revenue*, such error may be material to the outcome.

- Given the potential for error in the estimation of net market benefits, the sensitivity of this variable to key assumptions, and the impact that this error could have on the setting of the maximum allowable revenue, we think it prudent to undertake a more comprehensive assessment of the setting of the regulatory asset value.

- In doing so, it would be useful to refine the framework for estimation of market benefits, including the setting of key parameters underlying the estimation of market benefits.

- We see the ODV approach as offering a robust framework in which to place the setting of the opening asset base – which we view as amenable to the approach proposed by MTC.

APPENDIX A – ASSESSMENT OF CHARLES RIVER ASSOCIATES REPORT - MURRAYLINK MARKET BENEFITS

The study conducted by TEUS to determine the gross market benefits of the Murraylink interconnector is contained in Appendix D of the Murraylink Transmission Company application. Charles River Associates (Asia Pacific) Ltd ("CRA") was engaged to independently review and verify the work of TEUS, and its report ("the Review") is contained in Appendix E of the application. This note assesses the CRA report.

1.1 Scope of CRA Review

The CRA report is divided into four parts. It:

1. focuses on the models and methodologies used by TEUS to determine the market benefits conferred by the Murraylink interconnector;

2. briefly discusses the compliance of the methodology with the regulatory test;

3. broadly reviews the data and assumptions used by TEUS; and

4. comments on the results of the market benefits evaluation.

The Review contains two appendices. The first consists of a table that evaluates the consistency of the TEUS methodology and assumptions with the IRPC's SNI study. The second is a letter that comments on whether the results of the TEA load flow analysis have been appropriately incorporated into the models.

1.2 What the Review is not

The Review does not contemplate projects that are an alternative to the Murraylink project. Although CRA says that the consideration of alternative projects has clearly been identified as a major requirement in the regulatory test, it acknowledges that the TEUS study deals with the estimation of market benefits for Murraylink. CRA has therefore simply noted (on page 4) that while the Review was being prepared, separate studies were undertaken by MTC and its other consultants to address alternative projects.

The Review does not evaluate the inputs to the PSS/E load flow analysis that was used to derive the Murraylink transfer capabilities (pp20 & 32), and it does not evaluate the claimed benefits from the deferral of the Riverland augmentation (p20).

1.3 Applicability of the Result as a Regulatory Asset Values

CRA has endeavored to judge whether the TEUS market benefit study is sufficiently accurate for the purpose intended, but it does not discuss this purpose or consider its implications. Its judgments, therefore, may be of limited value with regard to whether the results are of sufficient quality to establish a regulatory asset value.

Generally, the value judgments that CRA makes on the quality of the methodology and results are positive (the italics are ours):

> *"The methodology is reasonably accurate and robust" (p4)*
>
> *"My review of the general methodological approach adopted by TEUS suggests that it is broadly reasonable for the purpose of evaluation of benefit associated with an interconnector" (p2)*
>
> *"The methodology for calculation of market benefits is sufficiently detailed and matches the intent of the regulatory test" (p17)*

1.4 Limitations of Software

SEIL has noted the potential for the results of the analysis to be affected by the choice of software and the configurations of the model(s).

> *"The methodology for calculation of capacity deferral benefits using a profitability test is reasonably accurate and matches the intent of the regulatory test." (p17)*
>
> *"TEUS have adopted a reasonable compromise (to the problem of commissioning future generation) by using a 'profitability test' around detailed dispatch model i.e., PROSYM… (This is) consistent with the methodology adopted by IRPC/ROAM for evaluation of SNI." (p8)*
>
> *"Both MARS and PROSYM use relatively simplistic representation of transmission and the time/season varying MW limits are the only means to represent the transfer capability in both their models." p32*

1.5 Multiple Scenarios

In its review of the TEUS study, SEIL notes that the application contains only three market development scenarios, and no sensitivity tests. Furthermore, the calculation of the proposed regulatory asset value has been based on only one of the scenarios.

The CRA report notes that there is a regulatory test requirement for various scenarios and sensitivities to be evaluated:

> *"A balanced selection of scenarios is an essential part of the regulatory test to capture the uncertainties in market development over the long run….In addition to 'scenarios', a range of sensitivities for critical parameters is useful to check the robustness of the estimates i.e., whether a*

> *all change in the parameter values lead to a significant swing in the benefit estimates." (p16).*

The Report, however, does not clearly state whether it believes that the TEUS study aligns with this particular intent of the regulatory test.

Two of the eight key points made by CRA on the alignment issue relate to the regulatory test's requirement for scenarios and sensitivity test to be undertaken.

> *"(2) Consideration of new generation alternatives is consistent with the norms laid out by IRPC;" (p16) and*

> *"(4) There is appropriate consideration of uncertainties in generation/transmission outages as well as alternative load growth scenarios performed." (p16)*

A point that CRA could have made in item (2) above is that the IRPC's SNI study models new reliability-driven generation by using two offer price scenarios—one at VOLL (similar to TEUS's approach) and one at SRMC. TEUS has not undertaken an SRMC pricing scenario for reliability-driven generation and, in fact, has not incorporated reliability-driven generation in its modelling. The IRPC (3.4.2.2 of the IRPC Stage 1 report) implicitly regards the two price offer scenarios for reliability-driven generation as important, as in its view it constitutes the distinction between the 'market-driven' scenarios and the "least cost market" scenario required by the regulatory test.

A reader might infer from item (4) above that consideration of uncertainties in generation/transmission outages and alternative growth scenarios are sufficient to meet the regulatory test requirement for a balanced selection of scenarios and a range of sensitivities for critical parameters. That would not be correct. The regulatory test requires, for example, that "The forecasts of spot price trends should reflect a range of market outcomes, ranging from short run marginal cost bidding behavior to simulations that approximate actual market bidding and prices." CRA points out on page 26 that the IRPC study has used an LRMC bidding scenario and also other scenarios that have been based on a variation of fuel prices.

Elsewhere, the Report states,

> *"Market development scenarios as indicated in the regulatory test imply varying critical uncertain parameters. TEUS have considered a variation in load growth as a consequence of higher and lower economic growth around the baseline scenario. In addition TEUS have also considered sensitivity of the results to discount rates." (p20)*

Although these discount rate and economic growth sensitivities have been carried out, there is no current solution to the problem of how the results may be used in calculating a regulatory asset value.

1.6 Benefits from the Provision of Ancillary Services

On page 9, CRA make the comment that TEUS has excluded reactive power, voltage, and voltage stability issues from the market benefits assessment framework. This is not strictly correct, since by including the deferral of the Riverland static capacitors in the assessment framework, TEUS has explicitly included reactive support as a market benefit of the Murraylink proposal.

1.7 Price Inflation

On page 19, CRA states that the short run marginal costs of generation by plant and the cost of building combined cycle gas turbine, open cycle gas turbine, and coal plants that have been used by TEUS have "specifically been obtained from the IRPC report". While they may have been obtained from the IRPC report, they are not identical to those in the IRPC report. In converting these financial values to May 2003 dollars TEUS has inflated them by 7.04%. On the other hand, the original developers and users of the assumptions, IRPC and ROAM Consulting, have assumed that the figures are already stated in year 2003/4 dollars.

The Report says on page 19:

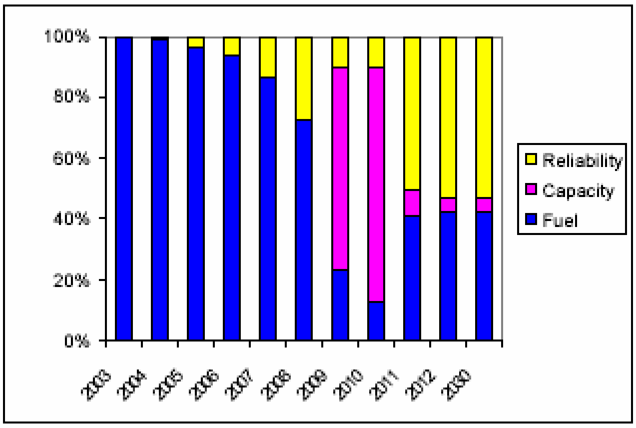
> *"The SRMC assumptions do not change over the years and therefore obviate the need for fuel price projections".*

This statement may not strictly be true. If, as CRA is saying, the benefit streams that have been derived are indexed to fuel prices, then the fuel price projections may need to be specified as the annual regulatory recoverable revenues derived from the NPV may need to be adjusted or inflated in a similar manner. Alternatively, if the benefit streams are considered to not be indexed to fuel prices, and instead indexed to rate of increase of the other price components of the benefits stream, (viz., VOLL, capital costs and demand side participation) then, in order to differentiate the various price deflators, explicit fuel price projections will still be required

1.8 Long Run Equilibrium

The following chart has been reproduced from figure 2 on page 22 of the report.

Figure 1 – Percentage share of annual benefit 2004-2013 and 2030 (from CRA report)



The chart depicts the percentage share of three components of the benefit—fuel cost savings, capacity deferral, and reliability—that have contributed to the market benefits in the base case economic growth scenario study. The chart does not incorporate the Riverland deferral benefits.

In this base case scenario, the generation capacity deferral benefits (merchant entry capital expenditure plus variable O&M savings and costs of voluntary load reduction) go negative in 2012. This is a result of Murraylink deferring the requirement for new generation from an earlier year. To prepare the chart (which would otherwise depict a negative percentage share) CRA has subtracted the $26.7m merchant entry capital expenditure saving from the year 2011 and added it back to the 2012's loss. This process effectively sets the merchant entry capital expenditures for years 2011 and 2021 to zero.

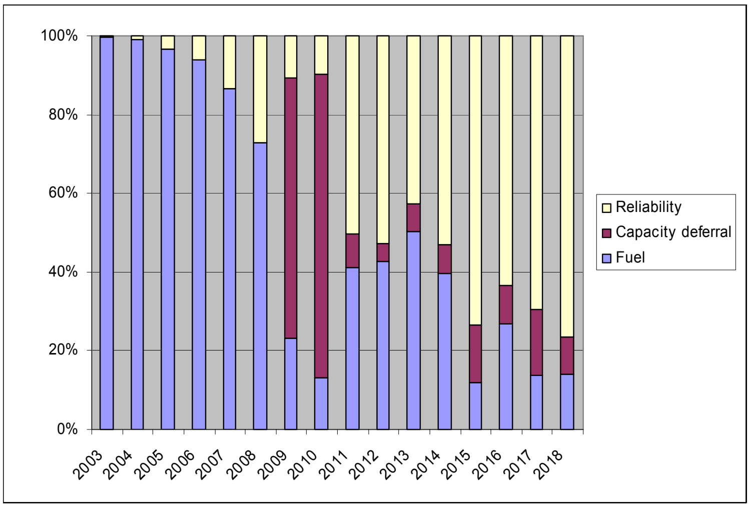
CRA has indicated on page 23 that its chart demonstrates that the relative shares of the benefits have remained nearly constant from 2011 onwards. It is clear that the shares must remain constant after 2012, since after this date the benefit components are all residuals and most, by definition are set to their year 2012 values. The only benefit stream whose residual is not set to its 2012 value is the merchant entry capital expenditure residual. This annual residual is defined to be zero, which coincidentally is identical to CRA's adjusted year 2011 and 2012 values.

Since, by definition the percentages shares beyond 2012 are set to the year 2012 values, and because it has removed the merchant entry capital expenditure savings from 2011, CRA's conclusion reduces to a statement that the relative shares of the reliability and fuel cost savings components in 2011 and 2012 are similar. CRA concludes that this "signifies that demand-supply scenarios at the two ends of the interconnector, and possibly in the other regions, have equilibrated."

The Report gives stronger evidence of equilibrium elsewhere on p23 where it indicates that TEUS has provided it with the results of a run performed for the year 2030. The share of benefits in that year, it says, match closely with those of 2011 and 2012, indicating that equilibrium was reached by 2012.

Since the Report was prepared, TEUS has prepared an unbroken sequence of annual runs that extend from 2003 through to 2018 (the "no black coal" variant). The ratios of fuel-cost-savings, reliability, and generation capacity deferral benefits (with the merchant entry capacity savings removed after 2010, as in the CRA analysis) are plotted in the chart below. This chart demonstrates that, with the sole exception of the years 2011 and 2012, there has actually been very little consistency in the ratios that CRA has studied.

Figure 2 – Percentage share of annual benefit 2004-2018 (from TEUS extended computations)



We believe that this calls into doubt CRA's conclusion that equilibrium is reached by 2012.

APPENDIX B – STANDARD ASSET LIVES

Provided as a confidential appendix to the Commission.