Market Benefit Assessment of Basslink in the Australian National Electricity Market

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ABSTRACT

Economic benefit assessment has become an integral requirement of transmission system planning in the context of electricity market deregulation around the world. In a deregulated electricity market, not only does transmission planning have to address technical requirements but also has to consider commercial issues linked to an electricity market. One of the prime goals of transmission planning is to ensure a fair distribution of economic benefits among the market participants (all those who produce, transmit and consume). These economic benefits attributable to a transmission interconnection generally appear as benefits to an electricity market and are referred to as market benefits. Even from a regulatory perspective, assessment of market benefits of a transmission interconnection is an essential requirement to ascertain its economic value.

The market benefit assessment of a transmission interconnector presented in this thesis is specific to the Australian National Electricity Market (NEM) consistent with the regulatory framework in the NEM. This thesis develops a market benefit assessment framework in accordance with Regulatory Investment Test for Transmission (RIT-T) to assess the economic significance of Basslink, one of six inter-regional transmission interconnectors in the Australian NEM. A long-term market benefit modelling framework comprising least cost modelling (LCM) and time sequential modelling (TSM) is developed and applied to undertake modelling of long term market benefits. PLEXOS, a leading power market modelling software is used for this purpose.

Economic analysis concludes that the presence of Basslink is of significant economic value in terms of market benefits for the ranges of market development scenarios (MDS) studied.

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CONTENTS

GLOSSARY

A	Ampere
ACCC	Australian Consumer and Competition Commission
AEMO	Australian Electricity Market Operator
AER	Australian Energy Regulator
AU$	Australian Dollar
B&B	Branch and Bound
CapEx	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CMD	Cubic Meter Day
CO_2-e	Carbon dioxide Equivalent
CPRS	Carbon Price Reduction Scheme
CSV	Comma Separated Value
Cumecs	Cubic Meter Seconds
DC	Direct Current
DSP	Demand Side Participation
EA	Economic Analysis
ESOO	Electricity Statement of Opportunities
FC	Fast Rate of Change
FOM	Fixed Operation and Maintenance Cost
FOR	Forced Outage Rate
GB	Giga Byte
GHz	Giga Hertz
GIT	Grid Investment Test
GJ	Giga Joule
GUI	Graphical User Interface
GWh	Giga-watt hour
HPC	High Performance Computing
HVdc	High Voltage Direct Current
IBM	International Business Machine
IC	Interconnector
km	Kilo-meter
kV	Kilo-volt
kW	Kilo-watt

LCM	Least Cost Modelling
LDC	Load Duration Curve
LLNL	Lawrence Livermore National Laboratory
LMP	Locational Marginal Pricing
LR	Linear Relaxation
LRET	Large Scale Renewable Energy Target
MC	Medium Rate of Change
MD	Maximum Demand
MDS	Market Development Scenario
MILP	Mixed Integer Linear Programming
MIP	Mixed Integer Programming
MLF	Marginal Loss Factor
MNSP	Market Network Service Provider
MOR	Maintenance Outage Rate
MRL	Minimum Reserve Level
MTTR	Mean Time to Repair
MW	Mega-watt
MWh	Mega-watt hour
NEM	National Electricity Market
NPV	Net Present Value
NSW	New South Wales
NT	Northern Territory
NTNDP	National Transmission Network Development Plan
NTS	National Transmission Statement
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
OpEx	Operational Expenditure
OPF	Optimal Power Flow
POE	Probability of Exceedance
PV	Photovoltaic
QLD	Queensland
RAM	Random Access Memory
R&D	Research and Development
RIT-T	Regulatory Investment Test for Transmission
RRN	Regional Reference Node
SA	South Australia
SC	Slow Rate of Change
SRMC	Short Run Marginal Cost
TAS	Tasmania
TEAM	Transmission Economic Assessment Methodology
TSM	Time Sequential Modelling
USE	Unserved Energy
VIC	Victoria
VoLL	Value of Lost Load
VOM	Variable Operation and Maintenance Cost
WA	Western Australia
WACC	Weighted Average Cost of Capital
XML	Extensible Markup Language

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Chapter 1

INTRODUCTION

1.1 GENERAL OVERVIEW OF TRANSMISSION ECONOMIC BENEFIT ASSESSMENT

Ever since the overall process of power system planning started, transmission planning has always remained an integral constituent of it. The introduction of deregulation in electricity markets has made transmission planning in the modern time a far more complex process, involving a number of technical and commercial issues of electricity market and its different stakeholders (those who produce,transport and consume) [1], [2], [3], [4], [5], [6]. Not only does transmission planning have to meet rigorous technical (including security and reliability standards) requirements, but also has to ensure that every stakeholder of the market is benefited rationally [5].This aspect brings in a very basic concept of social welfare to the electricity market, which provides an opportunity for fair treatment to all market participants. From the social welfare point of view too, it is equally logical that one category of the market stakeholder is not unduly benefited at the expense of other. This necessitates that new transmission additions, augmentations and upgrades should be judged from an economic perspective. Therefore, the importance of economic transmission planning has increased more than ever before in the context of such a multi-faceted planning process. As a result, an appropriate transmission economic benefit assessment methodology has evidently become not only necessary, but even mandatory from the regulatory perspective.

The transmission economic benefit assessment methodology appears under different titles in different countries around the world. For example, transmission economic assessment methodology (TEAM) is adopted by the California independent system operator to undertake economic transmission planning [7]. Similarly, Australia and New Zealand have such methodologies in the forms of regulatory investment test for transmission (RIT-T) and grid investment test (GIT) respectively [8], [9]. Whatever title is given to this assessment methodology, the objective is to maximise economic benefits, which are referred to as market benefits.

1.2 TRANSMISSION ECONOMIC BENEFIT ASSESSMENT IN THE NATIONAL ELECTRICITY MARKET OF AUSTRALIA

As a part of the regulatory requirement in the Australian National Electricity Market (NEM), transmission economic benefit assessment resulting from new transmission additions, augmentations and upgrades of regulated types are to be performed adhering to RIT-T devised by Australian Energy Regulator (AER) [8]. It is imperative to mention that such a transmission economic benefit assessment is mandatory for all regulated transmission investments. This assessment, termed market benefit assessment, assesses economic benefits, which is an integral part of RIT-T. In the NEM, there are examples of such a market benefit assessment being performed under RIT-T for merchant (unregulated) interconnectors (ICs) in an attempt to obtain regulated status [10], [11]. The research being undertaken in this thesis mainly covers the market benefit assessment aspect of Basslink, the only merchant (unregulated) transmission IC in the NEM.

1.3 THESIS OBJECTIVES

Given that the demand-supply balance in hydro-dominated Tasmania and mainland Australia have changed significantly since the idea of Basslink was originally conceived in the eighties, it raises an interesting question about its economic relevance in the changed context. This research explores whether Basslink is still worthwhile in the NEM taking into consideration different key market scenario drivers. The objective of the research being presented in this thesis is to assess long term market benefits attributable to Basslink, consistent with RIT-T framework.

To achieve this objective, a long term market benefit assessment framework is developed. A modelling process in line with this framework is undertaken to evaluate relevant long term market benefits. PLEXOS, a well known power system market modelling tool is used for this purpose. However, this research is NOT to be understood as a complete RIT-T for Basslink.

1.4 THESIS STRUCTURE

The chapters in this thesis are structured as follows:

Chapter 2: This chapter gives a brief introduction to RIT-T in the Australian NEM with an emphasis on market benefit assessment of transmission IC. Market benefit is defined and key market benefits are listed. Market benefit assessment requirements and application are discussed.

Chapter 3 : In this chapter, a brief introduction of the NEM and its regional transmission system are provided, which is followed by a special introduction to Basslink and the rationale for its development. The framework (along with its scope) for market benefit assessment of Basslink is presented. Types of market benefits to be evaluated are listed and discussed. Three market development scenarios (MDS) namely fast rate of change (FC), medium rate of change (MC) and slow rate of change (SC) from the list of projected MDS for the NEM are chosen. These MDS are discussed due to their great relevance in assessing scenario-specific market benefits attributable to Basslink.

Chapter 4: A modelling framework in line with the market benefit assessment framework is developed and presented in this chapter. Introduction to least cost modelling (LCM) and time sequential modelling (TSM) is made and also discussed. A brief discussion on economic analysis (EA) is also put forward. An introduction to the modelling tool, PLEXOS is made. Its salient features and simulation suite are discussed, which is followed by a detailed discussion of LT Plan, capacity expansion plan formulation in PLEXOS. Finally, the modelling process to be undertaken for the market benefit assessment in PLEXOS is presented and discussed.

Chapter 5: Input data and assumptions required for market benefit assessment modelling undertaken in PLEXOS are covered and discussed in this chapter. These comprise various NEM-specific input data, which include important data such as regional demand, existing/new entrant generator characteristics, regional transmission set-up, carbon prices and large scale renewable energy target (LRET). Based on these input data and assumptions, input database in PLEXOS is prepared for modelling.

Chapter 6: This chapter mainly covers economic analyses of the simulation results obtained from PLEXOS modelling. This includes quantification of scenario-wise long term market benefits along with a comparative analysis of trends of market benefits in three different MDS. Moreover, the trends of generation and installed capacity with and without Basslink in three different MDS are also discussed. A detailed commentary on the trends of different market benefits over the years of the planning horizon is made.

Chapter 2

MARKET BENEFIT ASSESSMENT IN THE NEM

2.1 INTRODUCTION TO REGULATORY INVESTMENT TEST FOR TRANSMISSION

The Australian Energy Regulator (AER), a part of the Australian Consumer and Competition Commission (ACCC) is an independent statutory authority [12]. It is responsible for economic regulation of electricity transmission and distribution services in the Australian NEM. RIT-T, devised by AER is a mandatory cost-benefit analysis test for regulated transmission network investments [8], [13]. This implies that transmission investments in the NEM, which include new transmission additions and upgrades of regulated type must comply and pass RIT-T to attain regulated status. As a standard cost-benefit analysis test, RIT-T provides a single framework for transmission investments either driven by reliability needs or motivated by the delivery of market benefits [8]. In both cases, market benefit assessment, which basically is a transmission economic benefit assessment, is mandatory.

2.2 MARKET BENEFIT ASSESSMENT OF TRANSMISSION INTERCONNECTORS

2.2.1 General Overview

In RIT-T, market benefit is defined as *a benefit to those who consume, produce and transport electricity in the market* [8]. The assessment of market benefits is an important constituent of the comprehensive RIT-T framework. It provides a prescription for the market benefits and costs of a particular transmission investment. As stated in RIT-T, all new transmission ICs, network augmentations and upgrades of regulated nature in the NEM must have to ensure that they are capable of maximising the present value of net economic benefits to all those who consume, produce and transport electricity in the market [8].

In the NEM, there are a number of instances of inter-regional transmission ICs, which were initially merchant (unregulated) ICs, and became regulated after fulfilling the regulatory requirements [10], [11]. Under safe harbour provisions of erstwhile National Electricity Code

Administrator (NECA), merchant ICs namely Murraylink (an IC connecting Victoria to South Australia) and Directlink or Terranora (an IC connecting New South Wales to Queensland) were converted to regulated ICs [14]. Market benefit assessment remained one of the main components in this whole process.

In both cases, a long term modelling framework was applied to estimate relevant market benefits attributed to them. For this purpose, modelling tools such as PROSYM, MARS were used [10], [15]. Both market benefit assessments were undertaken on a stand alone basis, i.e. without considering other new transmission options and augmentations capable of delivering similar level of market benefits [10], [15]. There are a few other market benefit assessment studies performed specific to the NEM [16], [17], [18].

2.2.2 Key Market Benefits

As a standard market benefit assessment framework for transmission, RIT-T has a list of various types of market benefit, which are required to be assessed [8]. Market benefits include those resulting from:

- Changes in fuel consumption due to different patterns of generation dispatch;
- Changes in voluntary load curtailment (dispatchable demand);
- Changes in involuntary load shedding for consumer value of electricity;
- Changes in costs for stakeholders, other than the proponent, due to:
- Difference in the operational and maintenance costs;
- Difference in the timing of new generation entry;
- Difference in capital costs;
- Changes in network losses;
- Changes in ancillary services costs;
- Differences in the timing of transmission investment;
- Competition benefits from the changes of participant bidding behaviour;
- Option value benefits.

2.2.3 Market Benefit Assessment Requirements and Application

As devised in RIT-T, a market dispatch modelling methodology must be used and incorporated to estimate the magnitude of market benefits. This requires a realistic treatment of generation characteristics including operational costs, network constraints and losses. Generally, market modelling on a least cost basis must be undertaken unless specific considerations of an individual market participant such as a private developer are more relevant [8], [19]. Moreover, an estimation of market benefits of a transmission IC must be able to capture benefits, which occur outside the region in which it is located. A discount rate must be chosen for present value calculations [20]. In considering any competition benefits (as a component of the total market benefit), it is required that the proper methodology must be identified to include it.

It equally underscores that the additional costs/benefits that cannot be measured in financial terms, or do not relate to producer/consumer surplus do not qualify to be included in the evaluation. Only the transfer of surplus, not the wealth transfer to one at the expense of the other is included as a market benefit [8]. This may relate both to technical issues as much as commercial issues.

2.3 SUMMARY

In the NEM, RIT-T provides a single regulatory framework for transmission economic benefit assessment required for transmission investments driven from reliability requirements and market benefit delivery. Market benefit assessment is one of the integral and mandatory components of RIT-T. The definition of market benefit, according to RIT-T is a benefit to those who consume, produce and transport electricity in the market. It also provides a detailed list of key market benefits attributable to a particular transmission investment. It is essential that all transmission investments of regulated type must maximise the present value of economic benefits to all market participants. RIT-T also prescribes certain market benefit assessment requirements.

Chapter 3

MARKET BENEFIT ASSESSMENT OF BASSLINK

3.1 REGIONAL TRANSMISSION SYSTEM IN THE NEM

3.1.1 General Overview

NEM is an integrated wholesale electricity market operating in the south and eastern states of Australia supplying electricity to Queensland (QLD), New South Wales (NSW) including the Australian Capital Territory, Victoria (VIC) and South Australia (SA) from December 1998 [21]. With the entry of Tasmania (TAS) in 2005, NEM currently comprises five interconnected regions largely following state boundaries. It is also the longest interconnected power system in the world covering a distance of about 5000 km, stretching from Port Douglas in QLD to Port Lincoln in SA [21]. Annually, trading of electricity in the NEM exceeds worth $10 billion to meet the electricity demand of more than eight million customers [21].

Since the NEM consists of relatively distinct and geographically distant generation and load centres, it relies on the regional transmission ICs for the trading of the vast bulk of electricity to its end use consumers [21]. Each region in the NEM is connected through regional transmission ICs, which are basically the high voltage transmission lines capable of transporting electricity between two adjacent regions. Depending upon their physical transmission capacities, these ICs aid the economic bulk trading of electricity in the NEM by facilitating import into the region when the demand is too high to be met by local generation alone or cheaper electricity in an adjoining region is available for export. The presence of these ICs makes inter-regional electricity trade possible and hence contributes to the increased supply reliability in the NEM.

3.1.2 Regional Interconnectors in the NEM

From the market operational point of view, regional ICs in the NEM are basically categorised in two main classes.

a. Regulated Interconnectors: Regulated ICs operate in accordance with the regulatory arrangement in place by AER and have passed the RIT-T [21]. These ICs are deemed to bring benefits to the NEM adding net market value to it. Irrespective of their actual usage, they are entitled to receive fixed annual revenue, according to their asset valuation set by ACCC [21]. The revenue is collected as a part of the network usage charges on end use consumers. Currently, five ICs in the NEM operate as regulated ones between all adjoining regions of the NEM, except Tasmania.

b. Unregulated Interconnectors: Unregulated or merchant ICs, also known as market network service providers (MNSP) are not required to pass RIT-T. They are free to derive revenue directly through trading in the spot market and are not eligible to obtain any fixed annual revenue. They are allowed to purchase from a lower price region and sell in a higher price region or can sell the rights to revenue generated through trading across it. Currently, Basslink is the only unregulated IC in the NEM [21].

Each NEM region has its own designated reference node where electricity spot prices (for the region) are set. These reference nodes are called regional reference node (RRN) [21]. Each IC is connected between corresponding RRN of any two NEM regions. Table 3.1 depicts brief information about transmission ICs in the NEM.

Table 3.1 Transmission Interconnectors in the NEM

Transmission Interconnector	Region 1	Regional Reference Node 1	Region 2	Regional Reference Node 2
NSW-QLD	NSW	Sydney West 330 kV	QLD	South Pine 275 kV
Terranora	NSW	Sydney West 330 kV	QLD	South Pine 275 kV
NSW-VIC	NSW	Sydney West 330 kV	VIC	Thomastown 66 kV
VIC-SA	VIC	Thomastown 66 kV	SA	Torrens island 66 kV
Murraylink	VIC	Thomastown 66 kV	SA	Torrens island 66 kV
Basslink	VIC	Thomastown 66 kV	TAS	Georgetown 220 kV

Figure 3.1 shows the regional transmission interconnection arrangement in the NEM.

Figure 3.1 Regional Transmission Interconnection in the NEM[1]

3.2 INTRODUCTION TO BASSLINK

3.2.1 General Overview

Basslink is a 400 kV high voltage direct current (HVdc) cable link connecting the island of Tasmania to the mainland of Australia [22]. This link stretches across the Bass Strait linking Loy Yang Substation in Victoria to George Town Substation in the northern Tasmania. This 290 km submarine cable portion of Basslink is the second longest of its type in the world. It has a rated DC current rating of 1250 A and a rated continuous power of 500 MW at the DC terminals of the rectifier converter stations [22]. The HVdc converter stations located at Loy Yang in Victoria and George Town in Tasmania are designed for power transmission in either direction. Moreover, Basslink HVdc system has a dynamic power transfer capacity up to 626 MW from Tasmania to Victoria to meet peak demand in Victoria [22].

This IC became available for commercial operation at midnight on April 29, 2006 and officially started trading in the NEM [23]. Since its commercial operation in 2006, it has been successfully operating as the only unregulated IC in the NEM.

[1] Australian Electricity Market Operator,An Introduction to Australia's National Electricity Market,2010

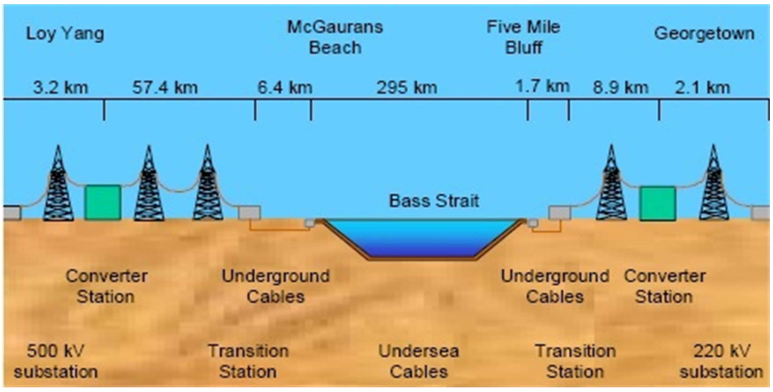

Figure 3.2 Key Components of Basslink[2]

Figure 3.2 shows key physical components of Basslink.

3.2.2 Rationale for the Development

Basslink was developed with the objective of facilitating economic power exchanges between Tasmania to the mainland, especially Victoria, through the better utilization of different generation sources available in these regions. Victoria has significant generation from brown coal generators operating almost continuously at high power output whereas the generation in Tasmania is mostly from hydro based generation sources. The start-up timings for these brown coal generators are longer and are used to supply the system base load. On the other hand, hydro generators, though they have their output limited by the water availability, are very efficient in meeting rapid demand rise in the system as they can be quickly brought into operation.

The development of Basslink creates an opportunity through providing an interconnection between energy-constrained Tasmanian hydro generation and capacity-constrained thermal generation in Victoria [22]. Tasmanian hydro generation can aid the inadequate Victorian peak generating capacity during its short term peak demand hours whereas Tasmania can import the available off peak power of the underutilized Victorian base load generating capacity [22]. This opportunity provides Tasmania a much required protection against risks of uncertain drought, low rainfall induced energy shortages. Under such a complementary arrangement, Tasmania will be able to import during the Victorian off peak hours as well as when prices are lower in Victoria. This import can help Tasmania reduce its local generation during off peak hours and keep its constrained generation for optimal use locally or export to Victoria during its peak demand hours. Similarly, Victoria will receive support for its constrained supply during its peak demand period from Tasmanian generation. This unique synergy contributes towards the efficient use of generation resources in the both regions and obviously delivers benefits to the

[2]T. Weseterweller and J.J. Price,Basslink HVDC Interconnector-System Design Considerations,IEEE International Conference on AC and DC Power Transmission,2006

NEM [22]. Therefore, Basslink is an important component of the NEM regional transmission interconnection, which gives Tasmania an access to the mainland generators and load centres of NEM.

3.3 FRAMEWORK FOR THE MARKET BENEFIT ASSESSMENT OF BASSLINK

3.3.1 Proposed Framework and its Scope

Aligning with the definition of market benefit and RIT-T framework, the proposed framework adopted for the market benefit assessment of Basslink identifies specific market benefits (not all the market benefits listed in RIT-T) and develops a long term modelling framework. The framework considers two different cases, i.e., the case where Basslink exists (Present Basslink Case) and the case where Basslink is assumed to be absent (Absent Basslink Case). A detailed economic analysis (EA) is an important part of the framework. Market benefit is evaluated for the two cases in each MDS. This evaluates the long term cost savings rendered by Basslink in different MDS and hence gives the market benefits attributable to it. Figure 3.3 shows the proposed framework applied for the market benefit assessment of Basslink.

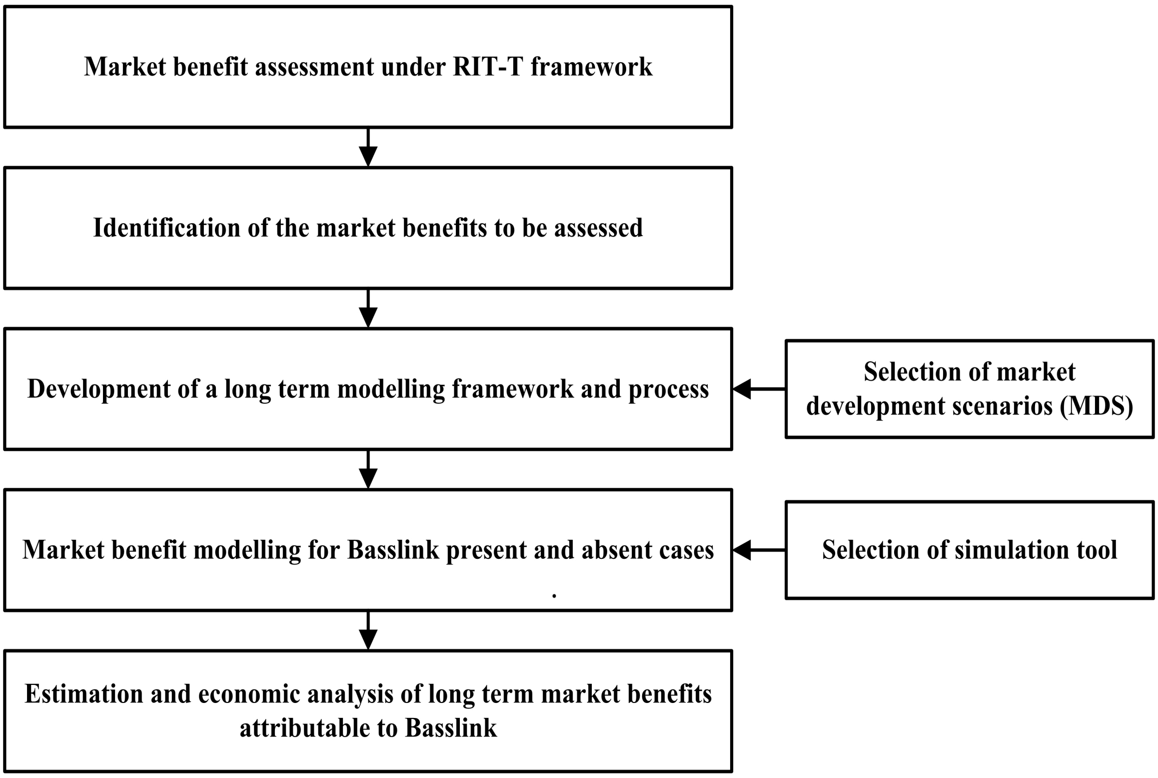

Figure 3.3 Market Benefit Assessment Framework

3.3.2 Types of Market Benefit to be Evaluated

The scope of this research is restricted to the evaluation of the certain market benefits attributable to Basslink. It, therefore does not consider all the market benefits enumerated in RIT-T. The research only considers the market benefits due to:

3.3.2.1 Reduced Operation Cost

Basslink enables inter-regional power flow, which is expected to increase an opportunity to displace expensive generation sources in one region with cheaper sources of generation in another region. Such an economical power exchanges favours the lessening of total system operation cost in the NEM [10], [15], [24], [25], [26]. This includes fuel cost, variable operation and maintenance (VOM) cost and applicable emission cost, whose reduction results in a benefit to the market in the form of operation expenditure(OpEx)savings. This market benefit is termed OpEx benefit.

3.3.2.2 Reduced Generation Investment Cost

With Basslink, there will be an efficient sharing of generation capacities and reserves across the NEM. Therefore, the pattern and timing of new generation entering the market to meet the demand growth and to maintain reliability requirements will be different from the case when Basslink is absent. Basslink may lessen or defer the need for investing in new generation schemes. The avoided capital cost from this reduced generation entry results in capital expenditure(CapEx) savings [10], [15], [24], [25], [26]. This is credited as a benefit to the market and hence referred to as CapEx benefit.

3.3.2.3 Reduced Unserved Energy Cost

A region has to maintain a high reserve level to ensure adequate reliability in the absence of interconnection with the adjacent regions. However, an interconnection between the regions makes reserve sharing possible and increases the system reliability. The system reliability is often measured in terms of unserved energy (USE) in the system.

Basslink allows the sharing of generation capacity efficiently and helps reduce the chances of capacity underutilisation in the NEM. Its presence is expected to equip the system to handle contingencies better and help lower the level of USE. Lowering of the amount of USE means enhanced system reliability and is considered a market benefit [10], [15], [24], [25], [26]. The benefit arising as a consequence of the reduced USE constitutes reliability benefit to the market.

3.3.3 Long Term Market Development Scenarios

3.3.3.1 Background

Australia is set to embrace a *low carbon economy* in sharp contrast to its historical *unconstrained carbon* economic trend. As it gradually prepares to move towards such a challenging environment, the Australian stationary energy sector will be significantly affected. This sector may eventually become quite different from what it is now. With greater uncertainty involved in projecting how the future energy sector and the associated market evolve, scenario drivers will shape the future landscape. A comprehensive study has been undertaken to identify the key scenario drivers responsible for the future development of the Australian stationary energy sector and market [27].

Carbon policy and pricing will be a leading scenario driver [27], [28]. Likewise, potential new generation technologies have been identified as one of the important scenario drivers [27], [28]. This may cause a major shift from the existing generation mix dominated mostly by carbon intensive coal generation. Similarly, fuel costs under the changed patterns of generation and fuel mix will likely to impact the long term development of the Australian energy sector [28].

Though these scenario drivers will have an influence, the Australian stationary energy sector will also be under the influence of energy demand growth, driven mainly by economic and population growth [27], [28]. This continues to be the dominant scenario driver. Also, with improved energy efficiency and new technologies, there will be a significant opportunity to manage peak demand through demand side participation (DSP).

Forecasting the variation of the scenario drivers involves a great deal of uncertainty [27], [28]. Moreover, projecting future states through the extrapolation of current patterns may not correctly capture the impacts in the long run. Instead, a 'what if' approach can be useful. Such an approach allows having one or more future states, which can represent a specific MDS. If there are several MDS, each may have an identical set of drivers, but represent only specific future state depending on their levels of impact exclusive to a particular MDS. The study has identified five MDS for the Australian stationary energy sector by 2030 [27]. These MDS are considered by Australian Electricity Market Operator (AEMO) to develop its National Transmission Network Development Plan (NTNDP) in 2010 [28].

The five MDS used in the preparation of NTNDP 2010 are titled:

- Fast rate of change
- Uncertain world
- Decentralised world (Moderate rate of change)

- Oil shock and adaptation
- Slow rate of change

In short, each MDS describes plausible outcomes for the Australian stationary energy sector by the year 2030, which include:

- the introduction of carbon charges on emissions, which are expected to result in transformed consumption patterns, generation fuel types and sources
- energy and maximum demand forecasts under different trends of economic and population growths

3.3.4 Scenario Description

The market benefit assessment of Basslink considers the following three MDS in consistent with the identified MDS for the Australian stationary energy sector.

- Fast rate of change (FC)
- Moderate rate of change (MC)
- Slow rate of change (SC)

The aforementioned three MDS cover different levels of variation of key scenario drivers. Such a selection gives an opportunity to fairly assess market benefits attributable to Basslink in different market conditions, especially different levels of socio-economic growth and carbon price trajectory, which are expected to be the most influential among identified scenario drivers. It will also give an opportunity to reasonably compare the variation of market benefits arising from Basslink. This provides an opportunity to analyse how market benefits attributable to Basslink vary across these MDS. Table 3.2 summarises key scenario drivers and salient features of each MDS.

Key features of each of these MDS are discussed here.

3.3.4.1 Fast Rate of Change(FC)

The fast rate of change (FC) MDS depicts a world with an international agreement on relatively strong emission reduction targets by both the developed and developing nations. It assumes that there will be a smooth transition to a carbon constrained future with the fulfilment of the

Table 3.2 Key Scenario Drivers

Scenario Drivers	**Fast Rate of Change**	**Moderate Rate of Change**	**Slow Rate of Change**
Economic Growth	High	Medium	Low
Population Growth	High	Medium	Low
Carbon Price	High	Medium	Low
Fuel Price	High Oil and Gas Prices	Moderate Oil and Gas Prices	Moderate Oil and Gas Prices
New Technology Cost	High	Medium	Low
Demand Side Response	Strong	Strong	Weak
Hydrology	Average	Average	Average
Emission target below 2000 level	25%	15%	5%

most provisional emission targets by 2030 and the successful introduction of policy frameworks by all countries to attain the ambitious global emission reduction target [28].

In Australia, an increased level of investment in low emission generation technology such as carbon capture and storage (CCS) makes its costs cheaper, partly due to combined efforts of government and industry. Strong emphasis will be placed on research and development (R&D) for commercially viable energy efficient and clean technologies. Renewable technologies in form of solar, wind, geothermal will become widely available for commercialisation. Electricity demand in this scenario is expected to be high due to high economic growth and sustained demographics.

This MDS, aiming for 25% CO_2-e (Carbon dioxide equivalent) emission reduction by 2020 relative to 2000 level across the economy as a whole has a carbon price trajectory ranging from AU$ 49.9/tonne in 2013/14 to AU$ 93.5/tonne in 2029/30 [28]. This relatively high emission reduction target would be met by the increased level of clean and energy efficient technologies, active DSP and diverse energy sources.

3.3.4.2 Moderate Rate of Change(MC)

The moderate rate of change (MC) MDS assumes a significant decentralisation of Australia's energy networks by 2030 with a considerable new investment in demand side technologies. Carbon price under this scenario ranges from AU$ 33.28/tonne in 2013/14 to AU$ 62.33/tonne in 2029/30, which has a moderate target of cutting down the CO_2-e emission level of 2000 by 15% in 2020 [28].

Low emission clean technologies and new base load generation technologies such as CCS, geothermal are found to be costlier than hoped, which limits their large scale uptake. Small scale distributed and renewable technologies such as wind generation emerge as economical alternatives to CCS, geothermal etc. generation sources. With the medium level economic and population growths, the electricity demand is likely to grow moderately.

3.3.4.3 Slow Rate of Change(SC)

The slow rate of change(SC) MDS is marked by low economic and population growth rates, both in Australia and the remaining world. These low growth rates coupled with limited investment resulting from a shortage of capital liquidity and high interest rates decelerate the transformation of the energy sector and market on the whole. Carbon price in this MDS varies from AU$ 23.92/tonnes in 2013/14 to AU$ 44.8/tonnes in 2029/30 with a target of reducing CO_2-e emission level in 2000 by 5% in 2020, which is the least among the three MDS [28].

New generation technologies are available with slightly higher costs (except moderate costs of CCS and geothermal). Low demand growth and relatively low carbon prices do not encourage greater investment in distributed generation technologies. Demand side participation turns out to be weak due to relatively low electricity prices and low economic growth rate.

3.4 SUMMARY

NEM is a wholesale electricity market covering five regions in the eastern and southern states of Australia. These distantly separate regions are connected through six regional transmission ICs to facilitate electricity trading. The regional transmission system is a key feature of the NEM, which includes regulated and unregulated regional transmission ICs. In the NEM, Basslink is the only unregulated regional transmission IC, which connects Tasmania to mainland Australia. The concept of Basslink was originated with an aim of economical electricity trading among five regions exploiting different available generation resources (huge hydro generation resources in Tasmania and coal based generation resources in the mainland especially in Victoria).

In this chapter, a market benefit assessment framework in consistent with RIT-T is proposed for assessing the economical significance of Basslink in terms of market benefits. Three types of market benefits, namely OpEx, CapEx and reliability (USE) benefits attributable to Basslink are considered for evaluation. Identification of consistent MDS is one of the important steps of the framework. Three relevant MDS, namely FC, MC and SC are chosen for the market benefit assessment of Basslink. Each MDS is unique, marked by key scenario drivers. Key scenario drivers include demand/demand growth, carbon costs, fuel prices and new generation technology costs. Salient features of each MDS are explained in this chapter.

Chapter 4

MODELLING FRAMEWORK AND PROCESS

4.1 AN INTRODUCTION TO MODELLING FRAMEWORK

Generally, the useful life of a transmission IC is long, i.e. around 40-50 years [3], [26], [29]. It is valid to assume that market benefits attributable to a transmission IC will occur continuously till the end of its useful life. This requires that a modelling framework for the market benefit assessment should have a time horizon sufficiently long to capture the market benefits accrued over its useful life [8], [26], [30], [31]. The framework should also have a consistent approach for scenario based modelling, which helps estimate the market benefits as well as compare and analyse their variation across different MDS in a transparent way. This scenario based modelling approach necessitates the inclusion of input data determined by the set of key scenario drivers for each of the MDS.

The proposed long term market benefit assessment of Basslink is being performed on a stand-alone basis, i.e., without considering other new transmission projects and upgrades. This particular assessment is specific to Basslink and therefore does not assess whether other transmission options are economically more favourable. The framework uses least cost modelling (LCM), which is necessary to determine scenario-specific long term generation development in the presence and absence of Basslink [26], [30], [31].

Time sequential modelling (TSM) is another important constituent of the framework. TSM optimises scenario-specific generation development plans, an important output from LCM along with other key input data for dispatch optimisation [26], [30], [31]. Key outputs from these two types of modelling form a crucial basis for assessing the market benefits originating from Basslink.

Figure 4.1 shows an overview of the modelling framework adopted for the market benefit assessment of Basslink. The modelling framework consists of three major steps.

- Least cost modelling (LCM)
- Time sequential modelling (TSM)
- Economic analysis (EA)

4.1.1 Least Cost Modelling (LCM) for Capacity Expansion Planning

Generally, LCM for capacity expansion planning identifies optimal location, capacity and timing of new generation and/or transmission candidates minimising total costs (capital and operation) taking into account technical and operational constraints [19], [26], [31], [32]. One of the distinct features of capacity expansion planning is the occurrence of integer variables (related to build decisions) and non-linear constraints (associated with power flow equations). The involvement of binary decision variables (build or not to build) renders capacity expansion planning a combinatorial optimisation problem [1]. With an increase in the number of decision variables, there will be a corresponding exponential rise in the number of calculations, sometimes referred to as *'Curse of Dimensionality'* [1]. This inherent complexity poses a great challenge for solution tractability. Mixed integer programming (MIP) addresses such difficulties and is commonly used in solving capacity expansion planning problems [31], [32].

LCM provides a co-optimised set of generation-transmission development and retirements over a planning horizon [31], [32]. LCM is based on a least-cost algorithm under MIP formulation and requires the construction of an objective function to represent total system cost, which is *minimised* subject to a set of constraints [31], [32]. The objective function is the total system cost, i.e., a sum of all economic costs encompassing OpEx (fuel, variable O&M, and applicable emission costs) and CapEx (build cost, fixed O&M (FOM) cost). Generation dispatch, new generation builds and unserved energy become important variables in LCM [32]. A defined set of constraints imposes physical and system limitations to the cost minimisation MIP model. They appear in the form of maximum power transfer capabilities (flow constraint) of transmission ICs, maximum available hydro and wind energy (energy constraint), capacity constraint, build constraint, emission constraint, generation constraint, minimum reserve requirement and user defined constraints reflecting important regulatory requirements etc.

LCM represents a least cost generator expansion plan under perfect competition, where each new generator candidate entering the market recovers its CapEx and OpEx [2], [33]. Being a long term optimisation problem, it is important that the time resolution of LCM is large to maintain computational tractability [32]. A load duration curve (LDC) approach is usually employed in modelling of load characteristics [1], [32]. It approximates hourly load over the entire planning horizon with a pre-defined (preferably one for each month) LDC with a fixed number of load

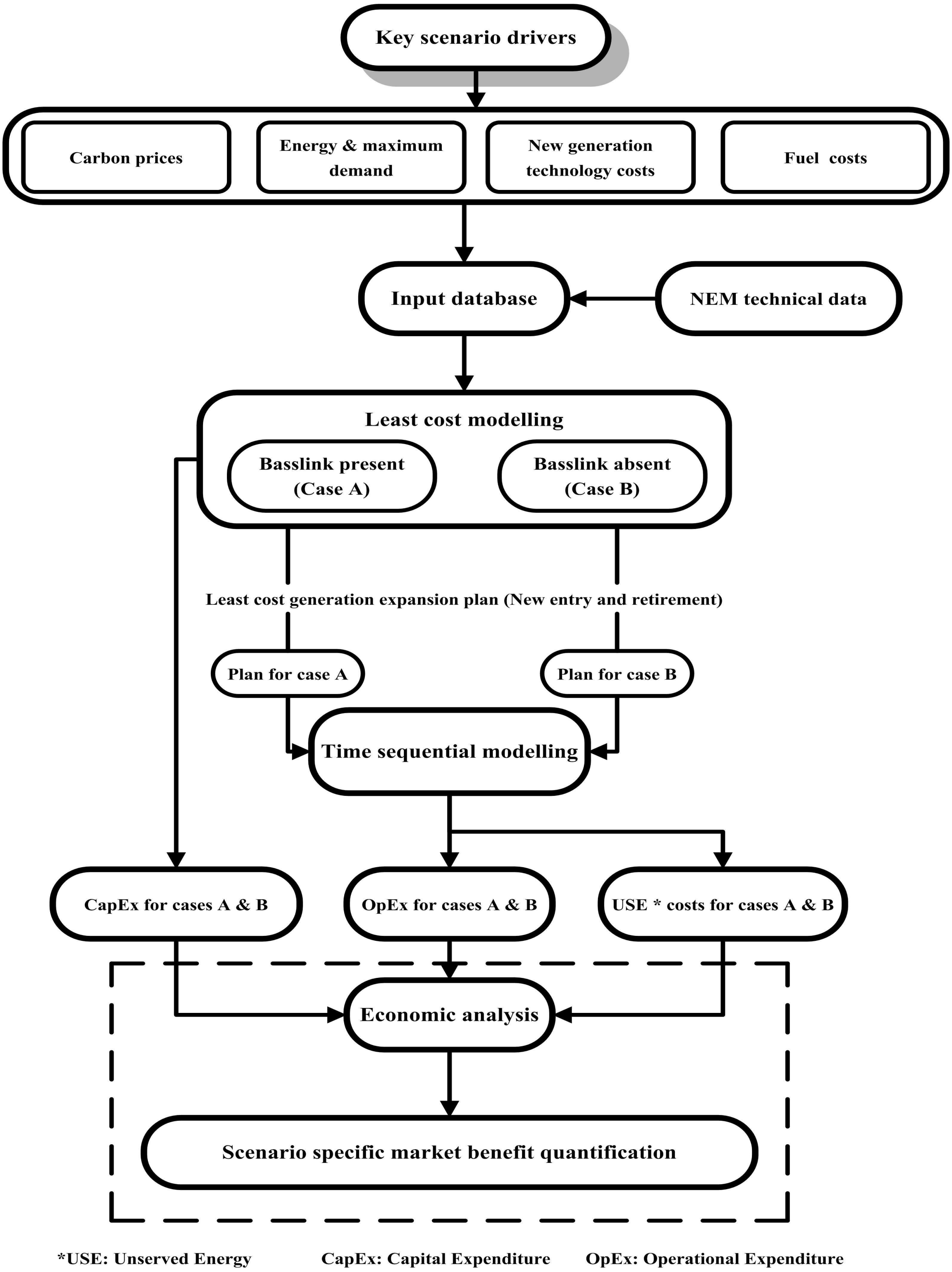

Figure 4.1 Modelling Framework for Market Benefit Assessment of Basslink

blocks [1], [31], [32]. The LDC approach allows LCM to solve this computationally intensive optimisation problem relatively quickly.

LCM is intended to explore an optimised generation development plan as the assessment does not consider new transmission and upgrade options. The objective of LCM is to find a scenario-specific set of new generation expansions and retirements over a planning horizon in the NEM on a least cost basis. For each MDS, LCM provides a detailed generation expansion plan (including retirements). It also provides the CapEx for such an outcome.

4.1.2 Time Sequential Modelling (TSM)

TSM is undertaken for a dispatch optimisation, i.e., for optimal generation scheduling to minimise dispatch cost subjected to transmission network constraints and reliability criteria [31], [32]. It performs an hourly generation dispatch across a given time frame assuming perfect competition where the objective is benefit maximisation to market [32]. TSM, therefore produces a detailed market operation outcome for a predefined capacity expansion (new entry and retirements) provided by LCM.

Key outputs of TSM are OpEx (operation cost) and USE cost with USE priced at the market value of lost load (VoLL). Long term planning like LCM is generally coarse in time (represented by a monthly LDC having fixed number of load blocks for each year of the planning horizon) to reduce the optimisation problem to a tractable size. TSM having an hourly resolution can more accurately fine tune market operation results and help remove obscurity from the model [32]. As a result, a better approximation of OpEx and USE cost can be estimated through TSM.

4.1.3 Economic Analysis (EA)

EA is a detailed cost-benefit evaluation. It chiefly estimates the benefits resulting from the followings:

- Avoided OpEx (OpEx benefit) due to the changes in operation pattern
- Avoided CapEx (CapEx benefit) due to changes in generator build pattern
- Avoided USE Cost (Reliability benefit) due to changes in USE

Given the long economic life of a transmission IC, benefits extending beyond the planning horizon have to be suitably captured using a terminal value, which simply represents the benefits at the end of the planning horizon [20], [26], [30], [32]. Benefits accruing past the modelled horizon would be excluded if the analysis is limited to this time horizon. To capture terminal value of market benefits, EA assumes that the market benefits at the end of the planning horizon remain the same until the end of the useful life of a transmission IC. In case of Basslink, total useful life is assumed to be 40 years.

It is to be noted that key scenario drivers such as carbon costs, fuel prices etc. continue to increase beyond the planning horizon, i.e. 2030, the aforementioned approach however is likely to be a conservative estimation of long term market benefits. Still, it is better than ignoring these end effects completely [17].

EA undertakes net present value (NPV) calculations with a system discount rate to estimate the accrued total market benefit discounted to present value terms [17], [26], [30], [34].

4.2 MARKET MODELLING TOOL - AN INTRODUCTION TO PLEXOS

4.2.1 General Introduction

PLEXOS for Power System (PLEXOS) is a MIP based power market simulation software, developed by Energy Exemplar (formerly Drayton Analytics), Australia [35]. Incorporating cutting edge mathematical programming and optimisation combined with the advanced data handling techniques, it provides a robust analytical framework for various aspects of power market modelling [35]. Its easy-to-use interface and powerful simulation engine enable a comprehensive power market modelling from short to long planning horizons. PLEXOS is also credited with the foundation for the mathematical formulation of New Zealand, Australia, Singapore, Ireland energy and spinning reserve markets [31], [35]. More recently, National Grid, UK has also selected PLEXOS as its market dispatch simulator. PLEXOS is globally used for solving problems in power market operation, market planning and risk management to transmission analysis, including locational marginal pricing (LMP) formation.

Some key applications of PLEXOS are:

- Unit commitment and economic dispatch
- Pricing and settlement
- Portfolio optimisation
- Outages and maintenance scheduling
- Scenario analysis
- Investment planning
- Emission modelling

- Security constrained dispatch
- Wind integration, transmission and ancillary services modelling
- Pumped-storage modelling
- Stochastic modelling and optimisation

4.2.1.1 Architecture

Figure 4.2 shows the basic architecture of PLEXOS. The input database for a particular model is in the form of an extensible mark-up language (XML) file [36]. It has model inputs categorised as variables, constraints, objects with relationships defined among them, together with other key modelling settings. Input database of PLEXOS can handle any level of detail, which varies depending upon the model simulations from short to long time horizon. For an instance, a database may contain only static generation capacities and maintenance schedules suitable for a medium to long-term capacity adequacy study; or it may have hourly data including generator technical constraints for use in a detailed chronological simulation. Data can be entered directly into the PLEXOS graphical user interface (GUI) or can be linked using external comma separated value (CSV) data files for bulky input data such as demand data [36].

PLEXOS Engine is the heart of PLEXOS architecture, which acts both as a compiler and a solver. It processes and optimises the model with the help of an appropriate mathematical solver (optimiser) available within this engine. Output data obtained from the model solution is written to a solution database, which is also an XML file. Required output data from the solution database can be customised suitably to prepare a solution report depending on the type and nature of simulation analysis.

4.2.1.2 Simulation Suite

Main simulation suites in PLEXOS are categorised as follows:

a. Long-term plan(LT Plan): LT Plan is long term capacity expansion planning with a time horizon typically in the range of 10 to 30 years. It makes use of an algorithm that determines the optimal combination of new generation builds/retirements together with new transmission upgrades and retirements, minimising the NPV of the total costs of the system over a planning horizon [32]. It uses a LDC approach to solve a long term optimisation problem in a single step. Optimisation is done using one of the MIP based commercial solvers such as CPLEX, XPRESS-MP etc., which is also an integral part of PLEXOS engine [37], [38]. Other simulation suites can also make use of these solvers.

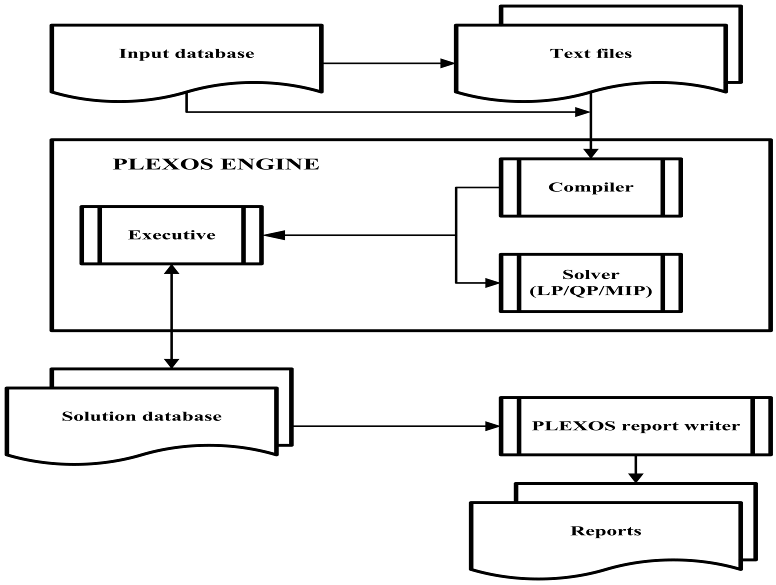

Figure 4.2 PLEXOS Architecture

b. Medium-term schedule(MT): MT is useful for mid term (typically with horizon spanning a year or shorter) operational planning [36]. MT also employs a LDC approach. While LT Plan is capable of solving a multi year optimisation problem in a single step, MT can solve an optimisation problem up to one year in a single step.

MT is extremely useful in decomposing long term objectives and inter-temporal constraints such as hydro usage into a set of equivalent short-term objectives and constraints to make them fit for further use in short-term simulation [36]. In the absence of proper decomposition, these constraints would be either ignored or approximated freely by ST, which would affect the quality of ST solution. The automatic decomposition of information resulting from the tight integration of MT with ST helps in correctly capturing the dispatch and pricing impacts of various inter-temporal constraints, for instance, energy limits, storage targets, trading strategy etc. [36]. Therefore, the real usefulness of MT during the integrated simulation (LT Plan-MT-ST) lies in linking the long term planning decisions from LT Plan to ST for more detailed simulation in relatively shorter time steps.

MT is also capable of generation expansion modelling but uses an algorithm different to LT Plan [36]. Other salient modelling features of MT include random outage modelling (multi-sample modelling using Monte Carlo simulation), gamed equilibrium for modelling medium term strategic objectives and financial optimisation.

c. Short-term schedule(ST): ST is designed to function as a day to day real market clearing engine, which is suitable especially for short term operational decision making. It performs a dispatch optimisation for every trading period, which is typically an hour or half hour depending upon a market dispatch and clearing engine [36]. This approach gives a more accurate dispatch optimisation than LT Plan and MT, which approximate time chronology using LDC approach. ST time resolution for a model simulation usually varies as low as from a minute to a day to sometimes week at maximum.

Among additional functionalities to deal with various short term operational decision-making, ST also includes an important feature of Monte Carlo simulation to perform random outage modelling, which is essentially a multi-sample simulation [36], [39].

4.2.1.3 Integration of Simulation Suites

The simulation suites can be used on a stand-alone basis or in any combination to suit the specific modelling requirements. But, more importantly, it is the full integration of these simulation suites, which allows a sequential execution of LT Plan, MT and ST. This sequential execution (LT Plan-MT-ST) makes it possible to pass down results from LT Plan to MT, whose results can also be used to inform ST. Such an automatic integration among simulation suites enables an effective linkage of long term planning decisions to medium or short term operational planning. This proves particularly useful in long term market modelling involving cost-benefit analysis, where the objective is long term CapEx, OpEx and USE cost estimation.

4.2.1.4 Model Aggregation in an Integrated Setup

PLEXOS can hold data to any level of detail. Depending upon the simulation requirement, it can be either more aggregated or less. LT Plan and MT usually follow a less detailed data set up using LDC approach for load modelling. A LDC represents the percentage of time that a particular load can be expected to remain above a certain level, which is obtained by sorting load in descending order [1], [31]. There is flexibility in specifying one LDC per day, week or month with a user able to choose a number of LDC blocks for the level of resolution required to approximate each LDC.

Relatively simplified transmission network topography (without considering intra-regional transmission lines) is preferred for LT Plan and MT [36]. Such aggregated data and network set-up reduce the computational burden for LT Plan and MT, which solve optimisation problems with long and medium time horizons respectively in a single step.

On the other hand, ST solves optimisation problems with shorter time horizon (in days or weeks) where objective is to explicitly simulate detailed chronological dispatch capturing operational activities of shorter duration. To fit into this simulation requirement, ST has a more detailed data set-up, for example, generator ramp rates, up-down times etc., a less granular time representation of load data, i.e. on hourly basis or even shorter and may have a detailed transmission representation (with intra-regional transmission lines).

4.2.1.5 Constraint Handling in an Integrated Setup

As LT Plan is a multi-year optimisation problem, it is capable of dealing with yearly or multi-yearly constraints involving build and retirement decisions, fuel constraints, emission costs and limits, regulatory requirements etc. The build and retirement decisions from LT Plan can be passed down to MT or ST, if required.

Similarly, MT optimises dispatch over a year at a time (in a single step) taking into account mid-term inter-temporal constraints. For example, fuel off take, hydro energy amount etc. may vary across the different periods of time, i.e. months of year, limiting their availability from one time period to another. As a result of these constraints, the decisions in one time interval are likely to affect those in the next or previous interval for an optimal outcome. MT has an inbuilt feature to decompose such inter-temporal constraints into inter-temporal constraints of even shorter duration i.e., decomposes monthly constraints to daily suitable for ST.

To correctly account for the effects of inter-temporal constraints in the modelling, the length of each simulation step must be able to cover the duration of these constraints. For instance, if there is an annual hydro energy constraint in the model, then LT Plan and MT must run at least for a year in a single step. Otherwise, this constraint would have no effect in the optimisation. For ST, this constraint needs further decomposition to shorter duration (usually done internally by PLEXOS in MT) suiting the time step chosen for the ST simulation.

4.2.2 Capacity Expansion Planning - LT Plan

4.2.2.1 Introduction

The term ‘capacity expansion planning’ in power market modelling refers to the identification of the optimal combination of generation-transmission expansion in the long run. The purpose of LT Plan is to determine the optimal set of new generation builds and retirements together with transmission upgrades and retirements minimising the NPV of the total system costs over a planning horizon. It solves a long term generation-transmission capacity expansion problem and a dispatch (also referred to as production) problem simultaneously from a central planning perspective [32].

4.2.2.2 LT Plan Formulation

The capacity expansion planning problem in LT Plan is formulated as a MIP, co-optimised with the production cost problem. Since LT Plan model is the system cost minimisation, the objective function is to minimise the NPV of OpEx and CapEx [32]. Depending upon the specific requirements of the modelling to be undertaken, LT Plan model can be formulated with additional features. The core MIP formulation, which includes both capacity expansion and production models, represents the basic LT Plan model. Tables 4.1 and 4.2 show some important terms in the core LT Plan MIP formulation [32].

Table 4.1 Parameters in LT Plan Formulation

Parameter	**Description**	**Unit**
D	Discount rate (DF_y) = $1/(1+D)^y$, which is the discount factor applied to year y	
L_t	Duration of dispatch period t	hour
$BuildCost_{g,y}$	Overnight build cost of a type of generator g if built in year y	\$/kW
$RetirementCost_{g,y}$	Overnight retirement cost of a type of generator g if retired in year y	\$/kW
$MaxUnitsBuilt_{g,y}$	Maximum number of units of generator g allowed to be built by the end of year y	
P_g^{max}	Maximum generation capacity of each unit of generator g	MW
$Units_g$	Number of installed generating units of generator g	
VoLL	Value of lost load	\$/MWh
$SRMC_g$	Short-run marginal cost of generator g SRMC = Heat rate (GJ/MWh) x Fuel price (\$/GJ) + VOM cost(\$/MWh)	\$/MWh
$FOMCost_g$	Fixed operation and maintenance cost of generator g	\$/kW/year
$Demand_t$	Demand in dispatch period t	MW
$PeakDemand_y$	System peak load in year y	MW
$ReserveMargin_y$	Capacity reserve required in year y	MW
FOR	Forced outage rate	%
MOR	Maintenance outage rate	%

Table 4.2 Variables in LT Plan Formulation

Variable	**Description**	**Type**
$\text{GenBuild}_{g,y}$	Number of new units build in year y for a type of generator g	Integer
$\text{GenRetire}_{g,y}$	Number of new units retired in year y for a type of generator g	Integer
$\text{GenDispatch}_{g,t}$	Dispatch level of a generating unit g in dispatch period t	Continuous
USE_t	Unserved demand in dispatch period t	Continuous

The objective function in LT Plan formulation thus becomes:

Minimise

$$\begin{aligned}\sum_y \sum_g DF_y \times [(BuildCost_g \times GenBuild_{g,y}) + (RetirementCost_g \times GenRetire_{g,y})] \\ + \sum_y DF_y \times [FOMCost_g \times 1000 \times P_g^{max} \times (Units_g + \sum_{i \leq y} GenBuild_{g,i})] \\ + \sum_y DF_y \times \sum_{t \epsilon y} L_t \times [VoLL \times USE_t + \sum_g (SRMC_g \times GenDispatch_{g,t})]\end{aligned}$$

Subjected to

a. Energy Balance: This constraint requires the total supply to meet the total demand in any dispatch period (each load duration curve block), which is approximated using LDC approach. Any supply short-fall resulting in an involuntary load curtailment appears as unserved demand (USE) in this equation to satisfy the supply-demand balance requirement. The energy balance constraint is thus represented as:

$$\sum_g GenDispatch_{g,t} + USE_t = Demand_t \quad \forall t \tag{4.1}$$

b. Feasible Energy Dispatch: This constraint imposes a restriction on a feasible amount of supply available for any dispatch period. Generator outages, approximated by forced outage rate (FOR) and maintenance outage rate (MOR) derate the energy contribution from a generator in a dispatch period, which is equated as:

$$GenDispatch_{g,t} \leq (1 - FOR_g - MOR_g) \times P_g^{max} \times (Units_g + \sum_{i \leq y} GenBuild_{g,i}) \quad (4.2)$$

c. Feasible Builds: This constraint imposes a limit on the maximum number of new generation entry that can be built in a year.

$$\sum_{i \leq y} GenBuild_{g,i} \leq MaxUnitsBuilt_{g,y} \quad (4.3)$$

d. Integrality: The Integrality constraint requires each feasible new generation build for a year to be an integer as a new generation build decision for a year can either be to build or not to build. Partial builds, even economic, are not allowed.

$$GenBuild_{g,y} \; Integer \quad (4.4)$$

e. Capacity Adequacy: Capacity adequacy constraint ensures that new generation builds occur just not for economic reasons but also to meet the required reliability criteria, i.e., the prescribed capacity reserve margin. Otherwise, new generation builds may occur solely on economic grounds, which may not meet the acceptable reliability standards. For example, capacity reserve margin and USE could take any value, failing to comply with the minimum reliability requirements.

$$\sum_{g} P_g^{max} \times (Units_g + \sum_{i \leq y} GenBuild_{g,i}) \geq PeakDemand_y + Systemloss_y + ReserveMargin_y \;\; \forall y \quad (4.5)$$

Additionally, LT Plan formulation can be enabled for the potential interchange of capacity across regions such that capacity can be shared within the limits of transmission network in a multi-region power system. Therefore, the spare capacity of a region can contribute to the capacity requirements of other interconnected regions accounting for non-coincident peaks. The LDC is devised on a monthly basis, and monthly coincident peaks are accounted for.

In addition to the above constraints incorporated in the core LT Plan MIP formulation, PLEXOS has several other *implied constraints*, which appear as inbuilt *short cut properties*. These implied constraints allow a user to relatively quickly create and include a constraint in a model.

Some of the most commonly used implied constraints in LT Plan formulation are:

1. Constraints representing energy constrained and intermittent generation resources:

- Maximum energy day/week/month/year
- Maximum and minimum capacity factor day/week/month/year

2. Constraints representing hydro storage:

- Storage target day/week/month/year

3. Constraints representing emission production:

- Max production day/week/month/year

4. Constraints representing fuel off-take:

- Maximum and minimum fuel off take day/week/month/year

4.2.2.3 Other Important LT Plan Features

4.2.2.4 Hydro Storage Optimisation

LT Plan is capable of hydro storage optimisation taking into account the long-term value of water in storage [40]. Smaller hydro units are generally modelled directly as either monthly or annual energy-constrained generating sources whereas larger hydro system with long term storage can be modelled as a more complex cascading network represented by physical water flows (natural inflows) and levels in the storage. For medium to long term storage where it is important that some water remain in storage at the end of each simulation step, there will be a future value of water left in the storage at the end of optimisation step. Either by defining a constant 'water value' or setting annual end volume storage, PLEXOS is able to optimise long term hydro storage [40]. This ensures better utilisation of water in storage resulting in an economic co-ordination among various generation sources.

4.2.2.5 Demand Side Participation

Demand side participation (DSP) is essentially consumer willingness to reduce a certain amount of demand voluntarily as a response to the market price. DSP is therefore the amount of load included in the demand of each region but can be available for the curtailment at a market price less than VoLL. DSP quantity is expressed as a curtailable load at the node selected as an option when price exceeds a user-specified level, indicated by DSP price. LT Plan has a feature of offering different DSP quantities available for curtailment under different DSP prices [36].

4.2.2.6 Intermittent Generation Resources

Generation intermittency affects the firm capacity of the installed generation resources, i.e. the capacity that can be relied upon during peak demand hours. However, generation intermittency, especially in cases of wind generation resources, has a more pronounced effect on the short term energy balance. Therefore, a single 'expected value' wind profile based on auto-correlation model (log-normal distribution) is used in LT Plan for modelling long term wind variability [36], [41]. The modelling of wind variability can also be done directly in the LT Plan formulation in case wind capacity is a significant proportion of available generation resources.

4.2.2.7 Transmission

LT Plan is able to model optimal power flow (OPF) or transportation flows. In a regional transmission setup where no intra-regional transmission lines are considered, LT Plan solves the model using transportation algorithm.

In a nodal transmission set-up where all inter and intra regional transmission lines are considered, the model is solved using a linearised DC OPF algorithm, which approximates the power flow equations to be linear, i.e. considers only real power flows. Losses can be expressed through loss factor equations or directly through polynomials accounting for quadratic losses.

4.2.2.8 Annualised Build and Fixed O&M costs

Generator build cost represents the capital cost per unit capacity (on per kW basis) of building a new generator unit, i.e. the all-in capital cost being incurred in the year of build (plant commissioning date). LT Plan formulation annualises the build cost of a new generators unit, converting the lumpy build cost to an equivalent yearly cost, which is applied each year from the year of build to the end of its economic life. This lumpy build cost is converted into an annualised build cost suitable for the LT Plan formulation as follows:

Annualised build cost = (Build cost_g x P_g^{max} x WACC_g)/ (1-1/ ((1+WACC_g)^{EconomicLife}))

Where:

WACC_g: weighted-average cost of capital, i.e. a minimum return on the investment in the wake of the investment risks and future uncertainties

Economic Life: the period over which the cumulative annualised build cost is equal to the build cost

The build cost coefficient (Build cost_g) is therefore replaced by the sum of the discounted annual build costs, beginning from the year of build until the end of the economic life of the unit. The discount rate will be system discount rate where as the WACC will be project or scenario-specific. The build cost is set to zero for years prior to the year of build. The annual fixed O&M costs (on per kW basis) for new units built as well as existing units can also be included in LT Plan.

4.2.2.9 End Year Treatment

Every planning model having a finite planning horizon suffers from a common problem known as end effects, which arises from an artificial end of the planning horizon [32], [42]. This sudden end of the planning horizon causes the benefits related to the current decisions not modelled in the years past the planning horizon. It is therefore possible that only low capital peaking generators (even if their marginal costs are high) will be selected towards the end of the planning horizon as the remaining utilisation years modelled may not be adequate to capture the long-term benefits associated with relatively capital intensive base load generators [32], [42]. This may directly influence the choice of new investments and result in a distorted capacity expansion plan.

Since every capacity expansion model has a finite planning horizon of typically 20 or 30 years, it is important that LT Plan formulation does not treat the end of the planning horizon as an ‘end of time’. LT Plan assumes that the system continues to expand after the final year of the planning horizon, i.e. the last year of the planning horizon continued to perpetuity.

4.2.2.10 Plant Retirements

LT Plan allows the co-optimisation of retirement decisions with investment decisions and optimises the timing of retirements. As a significant fixed cost is incurred to build new generator units and inefficient generators may not be dispatched, the units will be only retired if their retirements actually lower the system costs. The capital costs for the incumbent units are treated as sunk costs. It is largely the fixed operating and maintenance (FOM) cost that influences retirement decisions and decides economic retirements. LT Plan also allows a user to specify fixed retirement dates, if known for the existing units.

4.2.2.11 Planned and Random Outages

LT Plan uses a derating technique to take outages into account. Forced and maintenance outages represented by forced outage rate (FOR) and maintenance outage rate (MOR) respectively subtract the energy contribution of a generator in a dispatch period. FOR is distributed uniformly across a time whereas MOR is so distributed that less maintenance is scheduled during peak hours than during off-peak hours. For capacity adequacy purpose, forced and maintenance outages are not considered because reserve margin is used to account for these outages.

4.2.2.12 Market Bidding Behaviour and Competition

LT Plan formulation assumes a perfectly competitive market, which aims to maximise net market benefit from the social welfare point of view. There are, however a number of models of imperfect competition, which can be used in MT and ST to model competition and market bidding behaviour. LT Plan, by default only runs in a perfect competition mode.

4.2.2.13 Solution Method

For a MILP, there is a corresponding linear program known as the linear relaxation (LR) obtained by relaxing integrality constraints, making the problem less constrained than MIP [31]. If MIP is a minimisation problem, then the optimal value of the objective function of LR is less than or equal to that of the corresponding MIP. Therefore, the LR solution gives a lower bound for a cost minimisation problem. However, rounding the LR solution will not (in general) result into the optimal solution of MILP.

A most effective method commonly used for solving a MIP problem is Branch and Bound (B&B) technique [1], [31], [43]. This method starts by finding the optimal solution to the LR problem without the integer constraints. If decision variables with integer constraints have integer values in this solution, no further work is necessary. In case one or more integer variables have non-integer solutions, B&B method selects one such variable and associated branches creating two new sub problems and solving by further constraining the value of the variable. The process keeps on repeating till a solution satisfying all integer constraints is obtained. The commercial solvers incorporated in PLEXOS use heuristics in combination with B&B method for finding the integer optimal solution [31]. Heuristics aid the solver in finding a good feasible integer solution that can be compared against the existing LR solution found from B&B method.

At any instant during the simulation, there exists a gap between the best integer solution and the incumbent LR solution, which indicates the difference between their objective functions. This gap is a measure of the optimality and hence is used in setting termination criteria of the solution.

4.3 MODELLING PROCESS IN PLEXOS

The modelling process is basically a detailed formulation of the modelling framework along with input data and assumptions adopted to evaluate the long term market benefits attributed to Basslink. It makes an integrated use of three simulation suites of PLEXOS namely, LT Plan-MT-ST. Figure 4.3 depicts the modelling process in PLEXOS. It involves the following important steps, which are carried out for each MDS.

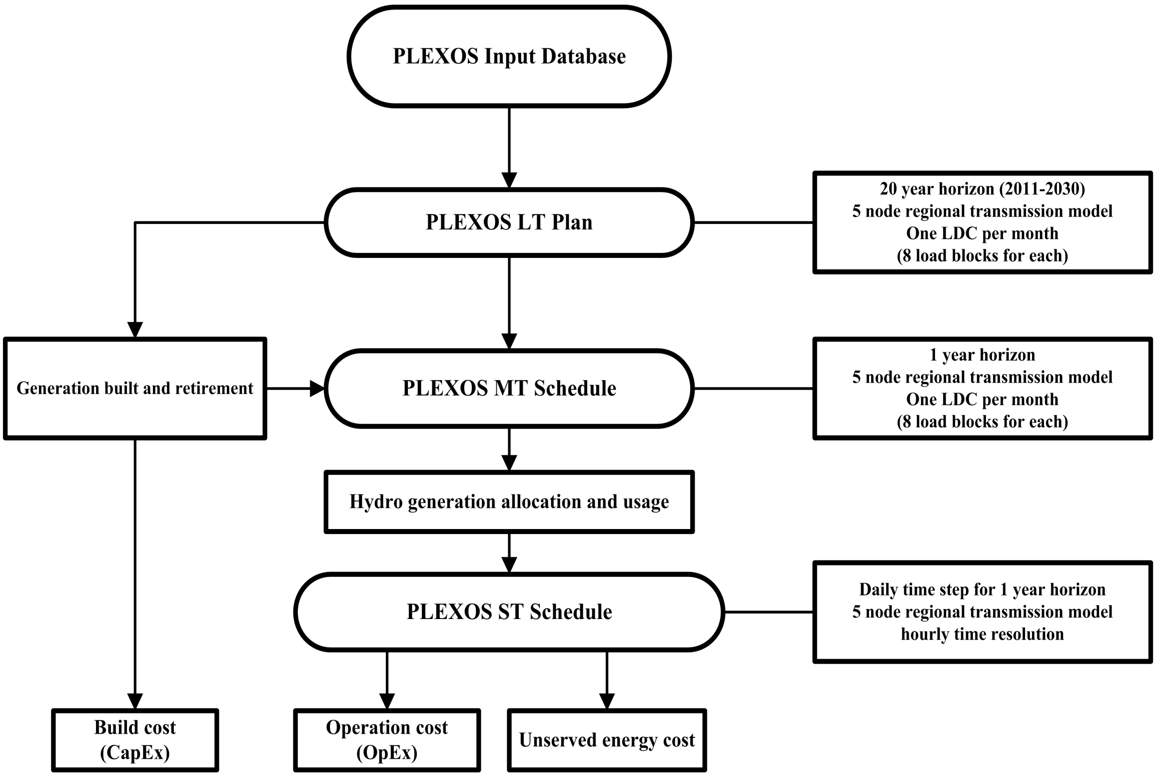

Figure 4.3 Modelling Process for Market Benefit Assessment of Basslink

- Setting up of the model
- Execution of LCM with a 20-year planning horizon to obtain a long term generation expansion plan using LT Plan
- Solving the model in the medium term (one year at daily intervals) using MT to assess hydro generation inflow limits
- Implementing TSM in the short term (one year at hourly intervals) for detailed generation dispatch using ST schedule
- Performing EA to determine scenario-specific market benefits attributable to Basslink (performed outside of PLEXOS)

a. Setting up of the Model: This is the first step, where a regional representation of the NEM is developed. Based on various features and assumptions for each MDS under consideration, all relevant input data required for the integrated simulation are incorporated in the database for the successful execution.

b. Least Cost Modelling (LCM): LCM provides an optimal technology mix, location, timing and capacity of new generation entrants in the NEM over a 20-year planning horizon. LCM is executed using LT Plan with the following simplifications to make it computationally tractable.

- Monthly load duration curve (LDC) approach is used to approximate hourly demand profiles for each month of a year over entire planning horizon. Each month of a year is represented by one monthly LDC having 8 load blocks thereby resulting in total of 96 time segments per year.

- LCM is executed in a single step (for a 20-year planning horizon) from 2011-2030 with no overlapping in between.

- Since all new gas generation entrants are of sizeable capacity, the investment decisions related to them are treated as integer whereas those for new small scale renewable generation entrants are treated linear. As these small scale renewable generation entrants such as wind, solar etc. consist of number of smaller units and are generally built in stages, it is not inappropriate to consider them as linear decision variables [31]. Also, linear build decisions for such smaller units are not likely to change optimal investment.

c. Time Sequential Modelling (TSM): Prior to TSM, MT (step 3) is run, which involves yearly simulation using generation input (build schedule) from LT Plan. Based on annual hydro inflows, storage capacities and hydro operational constraints, MT allots hydro generation on daily basis so as to optimise the use of water throughout the year. TSM takes build schedule and daily hydro allocation as inputs from LT Plan (step 2) and MT (step 3). It is run for all individual days of each year until the end of planning horizon with hourly time resolution. This leads to the better estimate of generation dispatch and line flows, thus, provide a better approximation of OpEx.

Similarly, Monte Carlo method with a large number of samples in TSM is required to estimate unserved energy occurring each year [36], [39]. For this purpose, 2000 samples are performed in TSM making use of high performance computing (HPC) resources. Each sample reports a specific value for unserved energy considering a unique pattern of forced and maintenance outages in the system. The mean of these samples is used to estimate unserved energy occurring each year.

4.4 SOLUTION CONVERGENCE CRITERION AND HARDWARE ARRANGEMENTS

PLEXOS 6.205 R06 (Gold Release) is used [35]. CPLEX 12.4.0.0 is chosen as an optimisation software [37]. LCM is executed on a desktop PC (2.8 GHz, Intel(R) Core (TM) i7) having 16 GB RAM. TSM is run on our departmental Linux cluster (Centos 5.3 x86-64 bit, Sun Grid Engine Scheduler) operating system on two of the nodes (dual AMD Opteron 2378 quad core processor, 16 GB RAM).

For a 0.5% gap between the non-integer and integer solution as the convergence criterion, the LCM solution takes approximately 9 hours, and the TSM solution takes approximately 3 hours of computation time. Maximum time limits specified for LCM and TSM are 86400 and 30000 seconds respectively.

For the sole purpose of estimating USE using Monte Carlo technique with 2000 iterations, some of the TSM runs were executed on Linux cluster of Lawrence Livermore National Laboratory (LLNL), USA on its 800 nodes (each node having two AMD Opteron 8356 CPUs, 32 GB RAM) [44]. Other TSM runs were undertaken on a Windows Server run by Energy Exemplar, USA (having two Intel Xeon E5-2670 CPUs and 96 GB RAM).

4.5 SUMMARY

This chapter discusses modelling framework and process, which are very important constituents of the market benefit assessment framework. The modelling framework applied to assess the long term market benefits attributable to Basslink is presented.

Taking into account key scenario drivers, the modelling framework has three main steps, LCM, TSM and EA. LCM is run for an entire planning horizon (20-year period) and gives a scenario-specific optimised generation expansion plan for each year and associated annual CapEx as its key outputs. TSM performs dispatch optimisation annually, thus provides amount of annual generation and associated annual OpEx. Similarly, amount of USE and associated USE cost (priced at VoLL) are also obtained from TSM. LCM and TSM are run for two different cases, i.e. with and without Basslink in each MDS. EA is undertaken to assess long term market benefits in terms of NPV of each type of benefit obtained from LCM and TSM.

Selection of the modelling tool is another essential feature of the market benefit assessment framework. PLEXOS, a well known power market modelling tool is used. Salient features including its integrated simulation set-up are discussed in detail in this chapter. An input database is set-up in PLEXOS incorporating all necessary technical and financial data required to undertake LCM and TSM. Using the integrated simulation set-up (LT Plan-MT-ST) available in PLEXOS, LCM and TSM are run in accordance with the defined modelling process. The solution convergence criterion (in terms of relative MIP gap and maximum time limit) and hardware arrangements for LCM and TSM runs are also discussed in this chapter.

Chapter 5

MODELLING DATA AND ASSUMPTIONS

5.1 BASIC ASSUMPTIONS

All input data are obtained from National Transmission Network Development Plan (NTNDP) 2010 and Electricity Statement of Opportunities (ESOO) 2010 unless otherwise stated [45], [46]. All financial (cost) parameters are in real AU$ 2009-2010 terms.

5.2 DEMAND DATA

5.2.1 Demand Profile

Based on the annual energy and maximum demand projections for the NEM over a 20-year planning horizon, AEMO has developed regional demand profile controlled by the NEM dispatch process for each of the MDS considered in NTNDP 2010. AEMO has also developed hourly demand trace for each region of the NEM representing 10% and 50% probability of exceedance (POE) maximum demand (MD) to account for both typical and extreme weather conditions. POE represents the likelihood of a MD projection being met or exceeded [1], [31].

FC, MC and SC MDS use respective hourly regional demand traces developed by AEMO in MDS 1, 3 and 5 of NTNDP 2010. LCM and TSM use 10% and 50% POE hourly demand traces respectively in consistent with NEM modelling [28], [30].

Energy and demand forecasts for the NEM are on the 'sent out' and 'as generated' basis respectively. Energy forecast on the 'sent out' basis comprises the consumer load (supplied from the network) and network losses, but not the auxiliary loads, i.e. station auxiliaries. On the other hand, MD projection presented on the 'as generated' basis includes consumer load, network losses and station auxiliary loads. AEMO applies *Scaling Factors* to convert 'sent out' energy forecasts to 'as generated' basis to maintain the consistency between the two forecasts to produce a regional demand trace.

5.2.2 Demand Side Participation

DSP in the form of voluntary load reduction (VLR) represents the consumer response towards high electricity prices during the hours of tight supply. DSP available in a region is priced at a RRN of the region, which represents the DSP pool price for that DSP amount. At higher pool price levels, greater amounts of VLR are available. For each year of the planning horizon, the total committed VLR available in each region is divided into four different DSP pool price bands as shown in table 5.1.

Table 5.1 Available Demand Side Participation

DSP Pool Price	**% VLR Participation (of Total VLR)**
AU$500/MWh	15%
AU$1000/MWh	20%
AU$2000/MWh	30%
AU$3000/MWh	35%

5.2.3 Unserved Demand

Unserved demand is treated as involuntary load curtailment, which is priced at VoLL. Unserved demand in the NEM is currently priced at AU$12500/MWh [47].

5.3 GENERATOR DATA

5.3.1 General Introduction

All generators in the NEM are classified under two broad categories; incumbent and new entrant generators. Incumbent generators are the existing ones in the NEM. New entrant generators are technically feasible new generator technologies, which may become part of the future NEM generation depending upon their financial viability.

5.3.2 Generator Characteristics

LCM and TSM consider various technical characteristics and cost parameters.

5.3.2.1 Existing Generator Characteristics

Existing generators in each region are further divided into following sub-classes.

- Baseload
- Intermediate
- Peaking
- Hydro
- Wind

Important technical and financial characteristics for the existing generators include:

- Number of units
- Maximum capacity
- Seasonal rating
- Minimum stable generation level
- Firm capacity
- Capacity factor
- Marginal loss factor (MLF)
- Station auxiliary loss
- Forced & maintenance outage rates
- Mean time to repair (MTTR)
- Variable O&M (VOM)cost
- Fixed O&M (FOM)cost
- Fuel cost (except renewable generation sources)
- Heat rate (except renewable generation sources)
- Firm retirement date (if known)

5.3.2.2 New Entrant Generator Characteristics

New entrants in each NEM region are categorised into:

a. Renewable: This category includes wind, solar, geothermal and biomass generation sources depending upon the resource availability in each region.

b. Gas: This type covers open cycle gas turbine (OCGT), combined cycle gas turbine (CCGT), combined cycle gas turbine with carbon capture and storage (CCGT-CCS). Unless 'committed (already scheduled)', all new entrant generators are modelled as 'generic'.

Following are the important physical and financial characteristics for new entrant generators.

- Number of units
- Earliest available date
- Maximum capacity
- Seasonal rating
- Minimum stable generation level
- Firm capacity
- Capacity factor
- Marginal loss factor (MLF)
- Station auxiliary loss
- Forced & maintenance outage rates
- Mean time to repair (MTTR)
- Build cost
- Variable O&M (VOM)cost
- Fixed operation & maintenance (FOM)cost
- Fuel cost (except renewable generation sources)
- Heat rate (except renewable generation sources)
- Maximum number of feasible builds
- Maximum number of feasible builds in a year

5.3.3 Assumptions for New Entrant Generators

5.3.3.1 New Entrant Gas Generators

a. Open Cycle Gas Turbine (OCGT): Typical size of an OCGT is 300 MW. Assumed maximum annual capacity factor and firm capacity for an OCGT are 97% and 99% respectively.

b. Combined Cycle Gas Turbine (CCGT): For all NEM regions, typical size of a CCGT is assumed to be 500 MW with maximum annual capacity factor of 92%. Firm capacity assumed for a CCGT is about 99.5%.

c. Combined Cycle Gas Turbine with Carbon Capture and Storage (CCGT-CCS): Typical size of a CCGT-CCS for all NEM regions is assumed to be 700 MW. A CCGT-CCS unit is assumed to be 99.5% firm. Maximum annual capacity factor of 92% is assumed.

5.3.3.2 New Entrant Renewable Generators

a. Wind: Wind generators are modelled as multiple units each of 1 MW. To represent the diversity of wind availability, three different categories of wind generators in each region are characterised [41]. With wind availability and diversity varying across the regions, average capacity factors are assumed to vary between 30-40% with intermittency represented by stochastic wind profiles [41]. Firm capacity of wind generators for the 10% POE peak demand is assumed to be less than or equal to 8% depending the upon particular region.

b. Geothermal: Geothermal generators are divided into two different classes based on the technology. Typical size assumed is 50 MW with a maximum annual capacity factor of 90%. Seasonal derating applies for summer seasons. Firm capacity of geothermal generation is assumed to be 90%.

c. Biomass: Typical biomass unit is assumed to be 50 MW with a maximum annual capacity factor of 90%. Seasonal rating applies with summer derating. A biomass unit is assumed to be only 80% firm indicating the possibility of non-firm fuel supply.

d. Solar: For a new entrant solar generation, fixed flat plate photovoltaic (PV) and solar thermal units are considered as multiple units each of 1 MW capacity. Generic profiles assuming no storage potential are used to represent the solar radiation potential throughout a day and across a year. Estimated winter profile is assumed to be 80% of that of summer season. PV/solar thermal units are assumed to be 80% firm.

5.3.3.3 Other New Entrant Generators

From both the technical and commercial point of view, various gas based generation technologies are identified as feasible future generation sources and are modelled as major future generation sources. However, advanced generation technologies such as integrated gasification combined cycle generators (IGCC) with and without CCS technology, integrated drying and gasification combined cycle generators (IDGCC) with and without CCS technology, supercritical and ultra-super critical coal generating units are not identified feasible under the most likely market environments and are not modelled.

5.3.3.4 Build Schedule, Size and Annual Build Limit

Tables 5.2 and 5.3 depict the NEM region-wise information on about new generation entrant technologies. This includes type of new entrant generation technologies, earliest available year, typical unit size (in MW) and maximum annual feasible build in the NEM.

Table 5.2 Availability and Typical Size of New Entrant Generator in the NEM

	Region									
Generator Type	**NSW**		**QLD**		**SA**		**VIC**		**TAS**	
	Earliest Available Year	**Unit Size (MW)**	**Earliest Available Year**	**Unit Size (MW)**	**Earliest Available Year**	**Unit Size (MW)**	**Earliest Available Year**	**Unit Size (MW)**	**Earliest Available Year**	**Unit Size (MW)**
OCGT	2011	300	2011	300	2011	300	2011	300	2011	300
CCGT	2012	500	2012	500	2012	500	2012	500	2012	500
CCGT-CCS	2020	700	2020	700	2020	700	2020	700	2020	700
Wind	2012	1	2012	1	2012	1	2012	1	2012	1
Solar	2012	1	2012	1	2012	1	2012	1	2012	1
Geothermal	2015	50	2015	50	2015	50	2015	50	2015	50
Biomass	2012	50	2012	50	2012	50	-	-	2012	50

Table 5.3 Maximum NEM-wide Annual Build Limit

Generation Technology	**Maximum Annual Build Limit (in MW)**
CCGT	5000
CCGT-CCS	5000
OCGT	5000
Wind	1500
Solar	100
Geothermal	400
Biomass	500

5.3.4 Existing Hydro Generation System

A small hydro system is modelled using monthly and annual energy constraints with their production restrained over the months of a year. For a larger hydro system, a cascading network depicting physical water flows and storage levels is set up in the database.

Flow patterns for a hydro system are assumed to remain the same over all years of the planning horizon and hence no yearly variations in the flow are considered. The average annual production figures for Snowy (excluding additional pump generation) and Tasmanian hydro schemes are assumed to remain the steady over the entire planning horizon.

Five hydro schemes have been explicitly modelled in the database.

a. Queensland Hydro Scheme: Kareeya, Barron Gorge and Wivenhoe hydro systems in Queensland are modelled. These hydro systems are set with maximum and initial storage volumes (in CMD, i.e. cumec days) along with monthly storage inflows (in cumecs).

b. Snowy Hydro Scheme: This hydro scheme consists of seven hydro stations namely Guthega, Blowering, Tumut1, Tumut2, Tumut3, Murray1 and Murray2. The combined average annual production from the scheme is assumed to be 4500 GWh, which excludes additional generation from pumping [48]. Lake Eucumbene acts as the main storage for the Tumut-Murray scheme with its inflows feeding the Tumut and Murray hydro systems. Guthega and Blowering hydro systems are modelled separately with storage inflows and monthly energy constraints.

c. Southern Hydro Scheme: Southern hydro scheme includes Dartmouth, Eildon,West Kiewa, McKay Creek and Bogong hydro power stations. Each of these stations is defined with appropriate monthly energy constraints.

d. Tasmanian Hydro Scheme: The Tasmanian hydro system is divided into three major hydro storage types namely, long term, medium term and run of the river. Each hydro station in the Tasmanian region is linked to one of the above three storages. Each of the three storages has its maximum and initial volume (in CMD) defined together with monthly natural inflows. Due to fluctuations in Tasmanian hydro generation over the years, average annual generation from the Tasmanian hydro scheme is assumed to be 8700 GWh [49].

e. Other Hydro Scheme: Other hydro schemes include Shoalhaven and Hume hydro generation system. Shoalhaven hydro system is represented as a pump storage system with pump efficiency of 70%, which is essentially a closed system with no storage inflows. On the other hand, Hume hydro system has its generation limited by monthly energy constraints.

5.3.5 Generator Retirement

Tables 5.4 and 5.5 depict the list of fixed and selectable generator retirements in the NEM. 'Fixed' indicates that the generator considered has the firm date of retirement. 'Selectable' is the unit considered for retirement if it results in a least cost outcome [32]. Not all generators are considered as selectable candidates for the retirement.

Table 5.4 Fixed Retirement Candidates

Name of the Unit	Retirement Year	Region
Munmorah	2014/15	NSW
Callide A	2015/16	QLD
Swanbank B1	2011/12	QLD
Swanbank B2,B4	2010/11	QLD
Swanbank B3	2012/13	QLD

Table 5.5 Selectable Retirement Candidates

Name of the Unit	No. of Units	Region
Liddell	1	NSW
Vales Point B	1	NSW
Wallerawang	1	NSW
Collinsville	5	QLD
Gladstone	6	QLD
Hazelwood	8	VIC
Morwell	3	VIC
Yallourn	4	VIC
Sunggery	3	SA
Torrens A	4	SA
Northern	2	SA

5.3.6 Generator Bidding Behaviour

For both LCM and TSM, all generators are assumed to follow short run marginal cost (SRMC) bidding approach. SRMC essentially comprises fuel,VOM and applicable emission costs for a generator. This approach assumes that generators do not exercise market power and hence represents a market with perfect competition [2], [36]. Since LCM assumes a perfectly competitive market, SRMC bidding approach under this assumption is expected to exactly recover operation and capital costs (including FOM cost) for each generator [2]. In the research being undertaken, Basslink is assumed to operate as a regulated IC. Therefore, it is supposed to follow dispatch related instructions from AEMO. Under such an assumption, it is not allowed to bid its transport capacity in the NEM and therefore does not levy any transport charge. No manual bids are assumed and modelled.

5.3.7 Miscellaneous Assumptions

a. Forced and Planned Outages: Planned and forced outage rates (expressed in %) are specified for all existing and new entrant generators.

b. Heat Rate Values: Heat rate (expressed in GJ/MWh) values are specified for all thermal and gas based generators. For each of them, an average heat rate value is used, which is assumed to remain unchanged over the entire planning horizon. Under such an approximation, no detailed heat rate modelling is required.

c. Marginal Loss Factor (MLF): Marginal loss factor (MLF) is an electrical distance of a particular generator to the RRN, which essentially acts as a substitute for transmission losses from the station gate to the RRN especially in regional models where no intra-regional loss modelling is done. Depending upon its location from the designated RRN of the region, each of the existing and new entrant generators is assigned with a specific MLF value [50].

d. Generator Ramping: No ramp rates are considered and generator ramping is hence not modelled.

e. Minimum Up-down Time: Generator minimum up and down time are not specified and is thus not modelled.

f. Generation and Fuel Contracts: These are not considered and are hence not modelled.

5.4 FUEL FOR THERMAL AND GAS GENERATORS

Depending upon the technology, availability, location and economical factors, types of fuel for the existing thermal and gas based new entrant generation sources across the NEM are categorised as follows.

- Black coal (especially in NSW and QLD)
- Brown coal (in Victoria)
- Natural gas

5.5 FINANCIAL PARAMETERS

Important cost parameters considered are the followings.

- Variable operation and maintenance (VOM) cost , expressed in $/MWh
- Fixed operation and maintenance (FOM) cost , expressed in $/kW/year
- Build (capital) cost, expressed in $/kW
- Fuel cost, expressed in $/MWh

VOM and FOM costs are specified for each incumbent and new entrant generators where as build cost is specified for each type of new entrant generators. For each MDS, build cost for each category of new entrant generators (for both renewable and gas) is specified along with a discount rate. A real pre-tax discount rate of 10% is used in all three MDS.

A scenario-specific WACC is chosen for each MDS to account for the investment uncertainty related to each MDS. WACCs (real pre-tax) considered are 8.78 %, 9.79 % and 11.78% for FC, MC and SC MDS respectively. Similarly, different set of fuel costs for various thermal and gas generators are specified to fairly account for the projected trend of fuel cost variations in each MDS [51].

5.6 TRANSMISSION DATA

Both LCM and TSM perform modelling of transmission ICs in the NEM on a pre-contingent basis, which assumes that all lines are present. No new transmission projects and upgrades are considered.

5.6.1 Transmission Network Representation

Both LCM and TSM assume regional transmission network topology. The NEM transmission network is modelled as a transportation network [32]. No intra-regional lines, transmission interfaces and other power system equipment are considered.

5.6.2 Interconnector Flows and Transfer Limits

For both LCM and TSM, inter-regional transfers through an IC are based on its physical limits [50]. These transfers, represented by static flow ratings are also referred to as forward and backward flows. Since the physical limits of an IC may not always be the same for both directions due to technical factors such as reactive power support, the values of forward and backward flows may be different for an IC. No generic transmission constraints and non-thermal stability limits (transient and oscillatory) are considered. Table 5.6 shows flow ratings for all regional ICs.

Table 5.6 Interconnector Flow Ratings

Transmission Interconnector	Region From	Region To	Forward Direction	Forward Flow Rating (in MW)	Backward Flow Rating (in MW)
NSW-QLD	NSW	QLD	into QLD	400	1080
Terranora	NSW	QLD	into QLD	122	220
NSW-VIC	NSW	VIC	into VIC	1900	3200
VIC-SA	VIC	SA	into SA	460	460
Murraylink	VIC	SA	into SA	220	220
Basslink	TAS	VIC	into VIC	594	478

5.6.3 Inter-regional Loss Model

LCM and TSM use inter-regional loss factor equations for modelling inter-regional losses across ICs. AEMO has loss factor equations, which are functions of flow and regional demand defined for the following ICs in the NEM [50].

1. Loss Factor Equation for NSW-QLD IC (South Pine 275 referred to Sydney West 330)

$$0.9967 + 1.9404 \times 10^{-04} \times NQ_t - 3.2842 \times 10^{-06} \times N_d + 1.3852 \times 10^{-05} \times Q_d \tag{5.1}$$

2. Loss Factor Equation for NSW-VIC IC (Sydney West 330 referred to Thomastown 66)

$$1.0848+1.747\times10^{-04}\times VN_t-3.5199\times10^{-05}\times V_d+9.0341\times10^{-06}\times N_d+7.4535\times10^{-06}\times S_d \tag{5.2}$$

3. Loss Factor Equation for VIC-SA IC (Torrens Island 66 referred to Thomastown 66)

$$1.0189 + 2.802 \times 10^{-04} \times VSA_t - 1.3328 \times 10^{-05} \times V_d + 3.743 \times 10^{-05} \times S_d \tag{5.3}$$

where,

Q_d = Queensland demand

V_d = Victorian demand

N_d = New South Wales demand

S_d = South Australian demand

NQ_t = Transfer from New South Wales to Queensland

VN_t = Transfer from Victoria to New South Wales

VSA_t = Transfer from Victoria to South Australia

Similarly, AEMO defines loss equations, which are functions of flow only for the remaining three ICs of the NEM [50].

4. Loss Equation for Murraylink (Torrens Island 66 referred to Thomastown 66)

$$0.0895 \times Flow_t + 1.306 \times 10^{-03} \times Flow_t^2 \tag{5.4}$$

5. Loss Equation for Terranora (South Pine 275 referred to Sydney West 330)

$$0.1009 \times Flow_t + 9.2321 \times 10^{-04} \times Flow_t^2 \tag{5.5}$$

6. Loss Equation for Basslink (Thomastown 66 referred to Georgetown 220)

$$4 - 3.92 \times 10^{-03} \times Flow_t + 1.0393 \times 10^{-04} \times Flow_t^2 \tag{5.6}$$

5.6.4 Reserve Sharing

NEM is an integrated power system, which operates under a centralized dispatch control [21]. Therefore, generation resources in a particular region of the NEM are assumed to be available to meet demands in any other region subjected to the transfer limitations. Reserve sharing is allowed in LCM satisfying the minimum capacity reserve margin defined for each region. For the purpose of LCM, annual minimum capacity reserves for each region are specified, which are calculated considering the support from ICs on annual minimum reserve level (MRL), which increases as year progresses.

5.7 CARBON PRICING TRAJECTORY

To incorporate carbon pollution reduction scheme (CPRS) in the NEM, carbon tax imposed on a generator in proportion to its measured level of CO_2-e (Carbon dioxide equivalent) emissions is modelled as emission cost. Three different carbon price trajectories (AU$/tonne CO_2-e) under FC (CPRS-25%), MC (CPRS-15%) and SC (CPRS-5%) MDS are considered. Table 5.7 gives assumed carbon cost for a particular year under three different carbon price trajectory.

Table 5.7 Carbon Price Trajectory (in AU$/tonne CO_2-e)

Year	FC(CPRS-25%)	MC(CPRS-15%)	SC(CPRS-5%)
2011/12	0	0	0
2012/13	0	0	0
2013/14	49.92	33.28	23.92
2014/15	51.92	34.61	24.88
2015/16	53.99	36	25.87
2016/17	56.15	37.44	26.91
2017/18	58.4	38.93	27.98
2018/19	60.74	40.49	29.1
2019/20	63.16	42.11	30.27
2020/21	65.69	43.79	31.48
2021/22	68.32	45.55	32.74
2022/23	71.05	47.37	34.05
2023/24	73.89	49.26	35.41
2024/25	76.85	51.23	36.82
2025/26	79.92	53.28	38.3
2026/27	83.12	55.41	39.83
2027/28	86.45	57.63	41.42
2028/29	89.9	59.94	43.08
2029/30-2030/31	93.5	62.33	44.8

5.8 LARGE SCALE RENEWABLE ENERGY TARGET (LRET)

Table 5.8 depicts Australia-wide annual large scale renewable energy target (LRET) [52]. Australia has set LRET to encourage entry of renewable energy generation sources to meet its growing electricity demand. Superseding previous mandatory renewable energy target (MRET) in January 2011, LRET requires 41000 GWh of generation by year 2020 to come from renewable energy resources, increasing from 10400 GWh in year 2011. For the purpose of LCM, the Australia-wide annual LRET target has to be scaled down as it only accounts for the generation occurring in the NEM, which does not include those in the Western Australia (WA) and Northern Territory (NT). Australia-wide annual LRET targets are scaled by 87% under an assumption of 13% of total Australian generation occurring in WA and NT [30].

Table 5.8 Australia-wide Large Scale Renewable Energy Target

Year	**Annual LRET (in GWh)**
2011	10400
2012	12300
2013	14200
2014	16100
2015	18000
2016	22600
2017	27200
2018	31800
2019	36400
2020-2030	41000

5.9 SUMMARY

Various modelling data and assumptions are discussed in detail in this chapter.

Demand data is of prime importance among modelling data. Hourly demand profile for each NEM region representing 10% and 50% POE MD in all three MDS are considered. DSP available in each region along with DSP pool prices is also incorporated. Unserved demand is priced at VoLL the NEM, i.e. AU$ 12500/MWh.

Important technical characteristics and financial parameters of existing and new entrant generation technology are also considered. In addition to this, maximum build limit and earliest available year of new entrant generation technology in each NEM region are also provided. Other important generator data includes existing hydro generation system in the NEM, generator bidding behaviour and generator retirements.

Regional transmission network set-up is assumed, which includes six inter-regional transmission ICs. IC flow ratings and loss model are also defined. Reserve sharing is allowed satisfying minimum reserve levels defined for each NEM region in each MDS.

Carbon pricing scheme is another important modelling data. In accordance with CPRS, carbon prices (in AU$/tonne CO_2-e) for each year in each MDS are used. Similarly, annual LRET specific to NEM is also modelled to take into account the mandatory requirement, which requires about 36000 GWh of energy must be generated using renewables by 2020 in the NEM.

Chapter 6

SIMULATION RESULTS, COMMENTARY AND ANALYSIS

In this chapter, the trends of generation and installed capacity with and without Basslink in each MDS are presented and described. It also depicts a detailed commentary on the simulation results, which include OpEx, CapEx and reliability benefits attributable to Basslink in three different MDS over a 20-year planning horizon. Quantification of these market benefits are presented.

6.1 COMMENTARY ON GENERATION TREND

This section demonstrates scenario-wise optimal future generation mix.

6.1.1 General Commentary

Generation sources are broadly categorised in three different types namely, coal, gas and renewable. Basslink, in general, by reducing the need for local peaking generation, results in less gas being used, more base load coal generation being run and greater renewables penetration.

6.1.1.1 Generation Trend in FC MDS

Figure 6.1 shows the trend of generation (in GWh) with and without Basslink in FC MDS. Generation from coal continues to dominate until the middle of the planning horizon despite some reduction for a few years, immediately after the introduction of the carbon pricing scheme (from 2013). Over the years, when carbon prices become significant, generation from coal starts to fall, which continues until the end of the planning horizon. The fall in coal generation is offset by a rise in generation from gas (including clean gas technology) and renewables. Whenever coal generation drops, there is a corresponding rise in the generation from gas and vice-versa. There is a clear generation trade-off between coal and gas over the years.

It is important to note that gas generation is not sufficiently economic to substantially replace the generation from coal even after the introduction of carbon prices. However, gas generation surpasses coal generation during the final years of the planning horizon. Generation from renewable sources also steadily rises over the years to fulfil the mandatory large scale renewable energy target (LRET). The trend of generation is not much affected by Basslink.

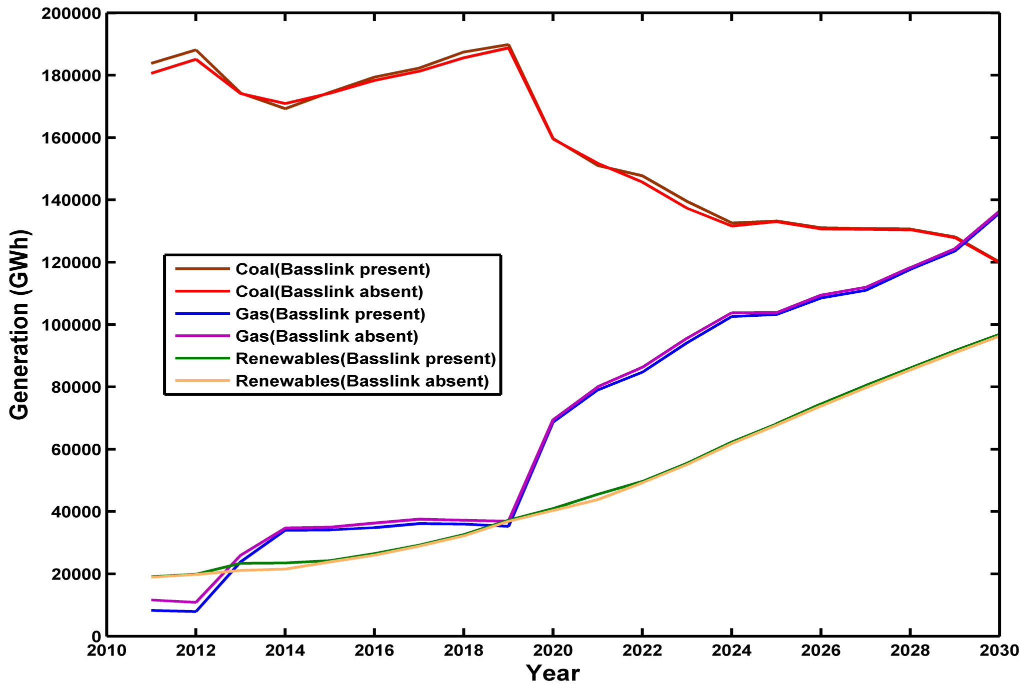

Figure 6.1 Generation in FC MDS

6.1.1.2 Generation Trend in MC MDS

Figure 6.2 portrays the trend of generation (in GWh) in MC MDS with and without Basslink. Coal still remains the dominant source of generation for all of the planning horizon despite some fluctuations over the years. Generation from coal slowly declines during later years of the planning horizon. Gas generation progressively rises. There is a noticeable rise in gas generation when coal generation starts to decline during later years. Generation from renewables, which even surpasses gas generation in some years, also follows the rising trend of gas generation but remains well below it. In this MDS too, the trend of generation does not vary markedly for Basslink present and Basslink absent cases, although Basslink does reduce gas generation and increases renewable generation. A trade-off between coal and gas generation is also observed in this MDS.

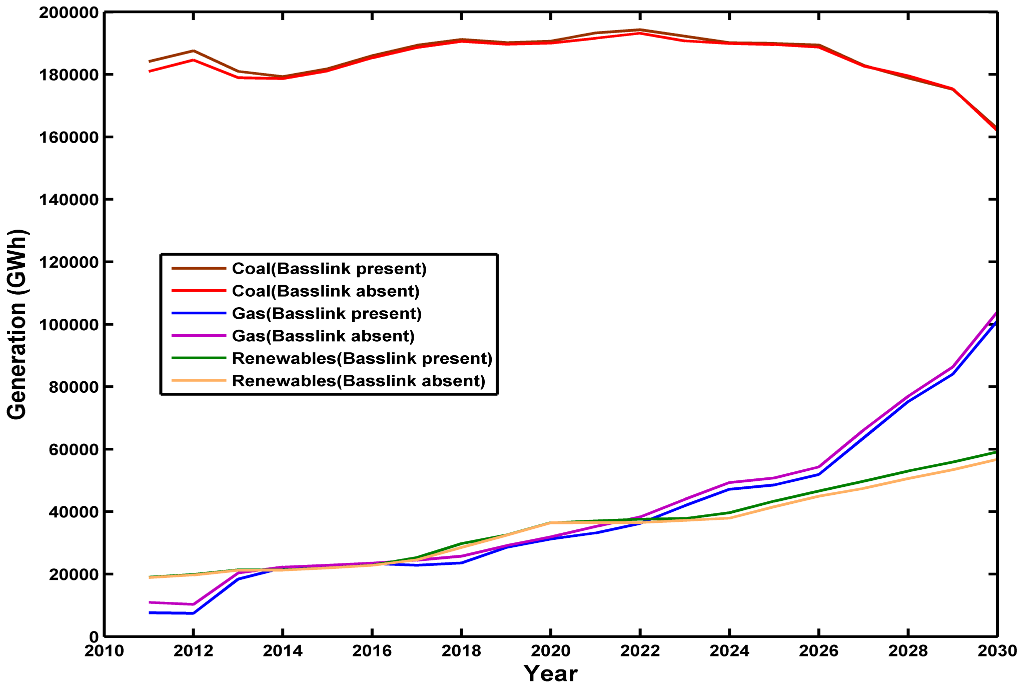

Figure 6.2 Generation in MC MDS

6.1.1.3 Generation Trend in SC MDS

The trends of generation (in GWh) in SC MDS with and without Basslink are shown in figure 6.3. As carbon prices are the lowest, coal remains the major and dominant source of generation, which continues to rise for most years of the planning horizon. Though the generation from renewables mostly surpasses that from gas, the contributions from renewables and gas are small compared to that from coal generation. Generation from gas does not rise noticeably until latter years of the planning horizon when the rising trend of coal generation slows down and decreases slightly. The generation from renewables rises slowly over the years to fulfil the mandatory LRET requirement. Compared to gas generation, coal generation rises steadily over the years supplanting gas generation well below it for the most years of the planning horizon. Generation in Basslink present and absent cases mostly follow the similar trend.

6.2 SCENARIO-WISE ANALYSIS AND COMMENTARY ON OPEX BENEFIT

In each MDS, OpEx benefit in a year is the annual savings in the operation cost (sum of fuel, VOM and emission costs). Though the trend of generation for Basslink present and absent cases does not vary markedly, the actual magnitude of generation (from coal, gas and renewables) does differ in these cases over the years. This section shows the OpEx benefit and difference in

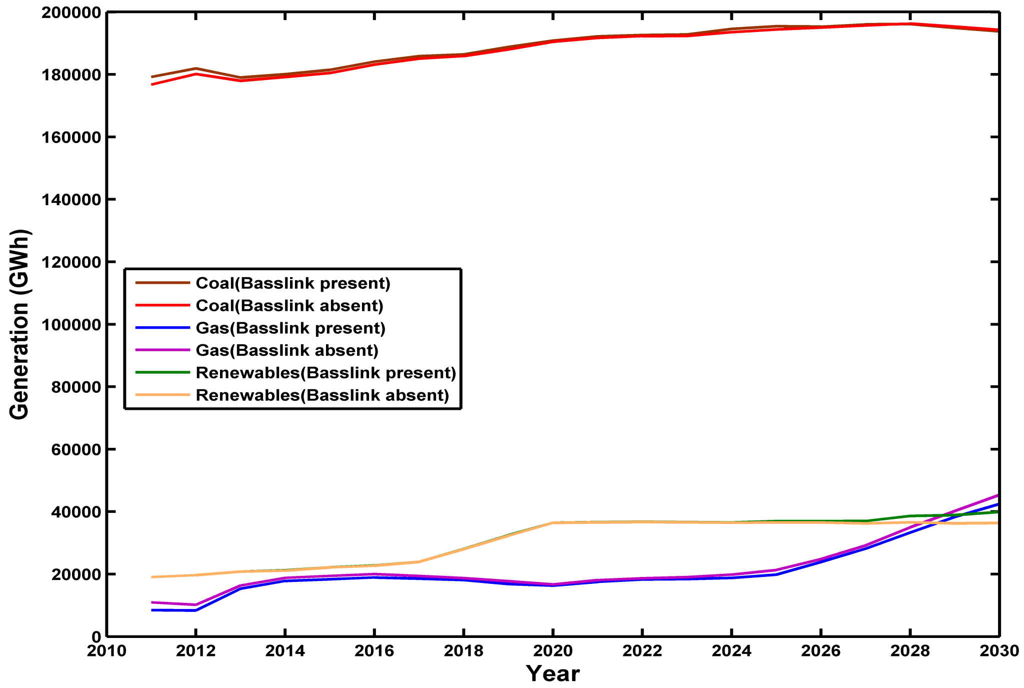

Figure 6.3 Generation in SC MDS

the mix of generation resulting from Basslink's presence.

6.2.1 Commentary on OpEx Benefit in FC MDS

Figures 6.4 and 6.5 show the OpEx benefit and the difference in generation in FC MDS respectively. Over the years, Basslink, in general, lowers the gas generation (including that from costly gas peakers) while encouraging more coal and renewable generation. In years 2013, 2014 and 2021, significant renewable generation is commissioned, resulting in considerable OpEx savings. In 2018, 2022 and 2023, Basslink has resulted in an increased OpEx. This is due to deferred investment in renewable generation technology, with coal generation meeting the demand. It should be remembered that OpEx and CapEx are co-optimised over the entire planning horizon, which can result in this sort of pattern.

6.2.2 Commentary on OpEx Benefit in MC MDS

OpEx benefit and the difference in generation in MC MDS are shown in figures 6.6 and 6.7 respectively. In this MDS too, Basslink encourages more coal and renewable generation, lowering gas generation (including that from costly gas peakers). This leads to an OpEx benefit. OpEx benefits rises significantly in years when Basslink lowers coal as well as gas generation. This is

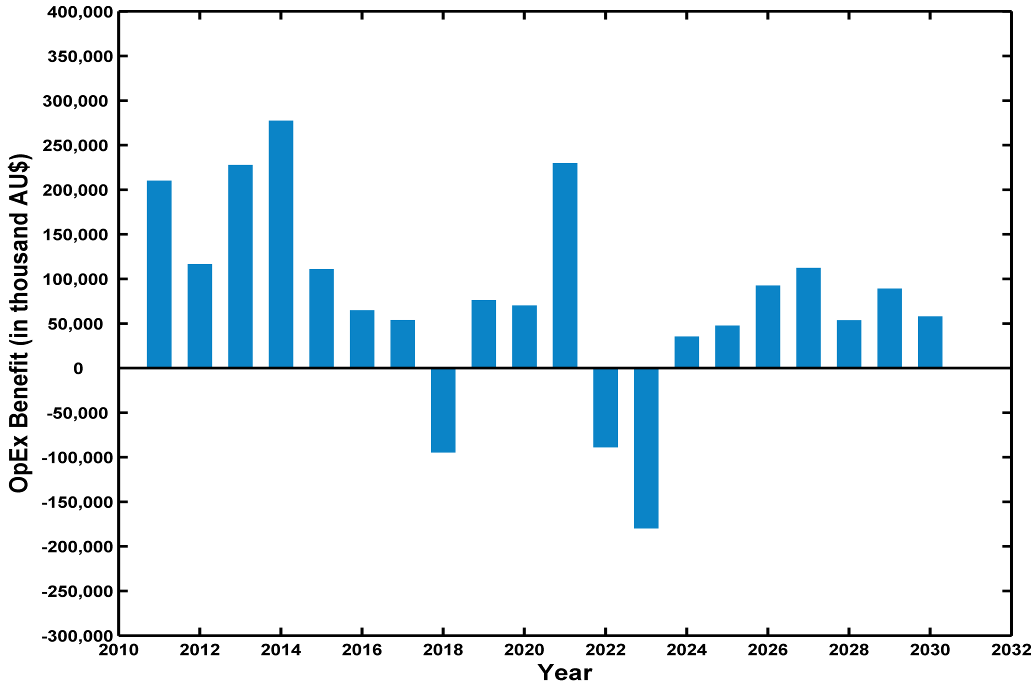

Figure 6.4 OpEx Benefit in FC MDS resulting from Basslink's presence

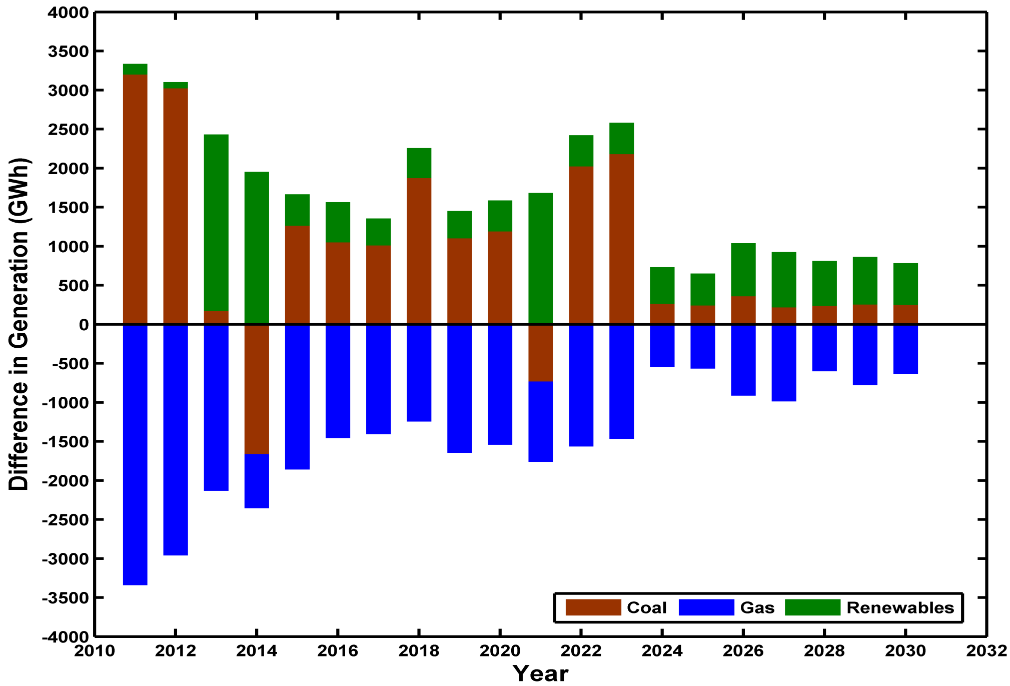

Figure 6.5 Difference in Generation in FC MDS resulting from Basslink's presence

possible as the flexibility that Basslink provides and allows more substantial and earlier installation of renewable generation compared to the FC MDS. The bulk of OpEx benefit and renewable generation is deferred by almost 10 years. In some years, Basslink runs more coal generation (with moderately rising carbon prices) high enough to offset OpEx savings from reduced gas generation. This leads OpEx benefit to fall significantly and go even negative in those years.

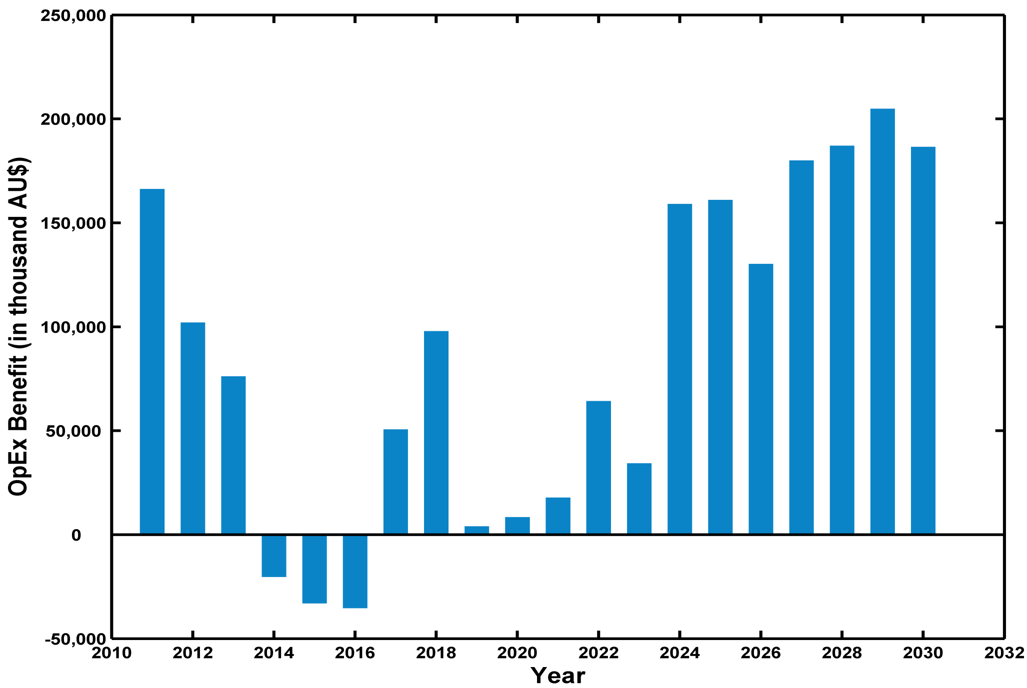

Figure 6.6 OpEx Benefit in MC MDS resulting from Basslink's presence

6.2.3 Commentary on OpEx Benefit in SC MDS

OpEx benefit and the difference in generation in SC MDS are shown in figures 6.8 and 6.9 respectively. Basslink still encourages more coal and renewable generation over the years lowering gas generation (including that from costly gas peakers). In the later years of the planning horizon, Basslink lowers coal as well as gas generation increasing generation from renewables, which leads to a significant rise in OpEx benefit. Significant renewable generation and its associated OpEx benefit is delayed by about 15 years.

6.3 COMMENTARY ON INSTALLED CAPACITY TREND

This section presents scenario-wise optimal future technology mix.

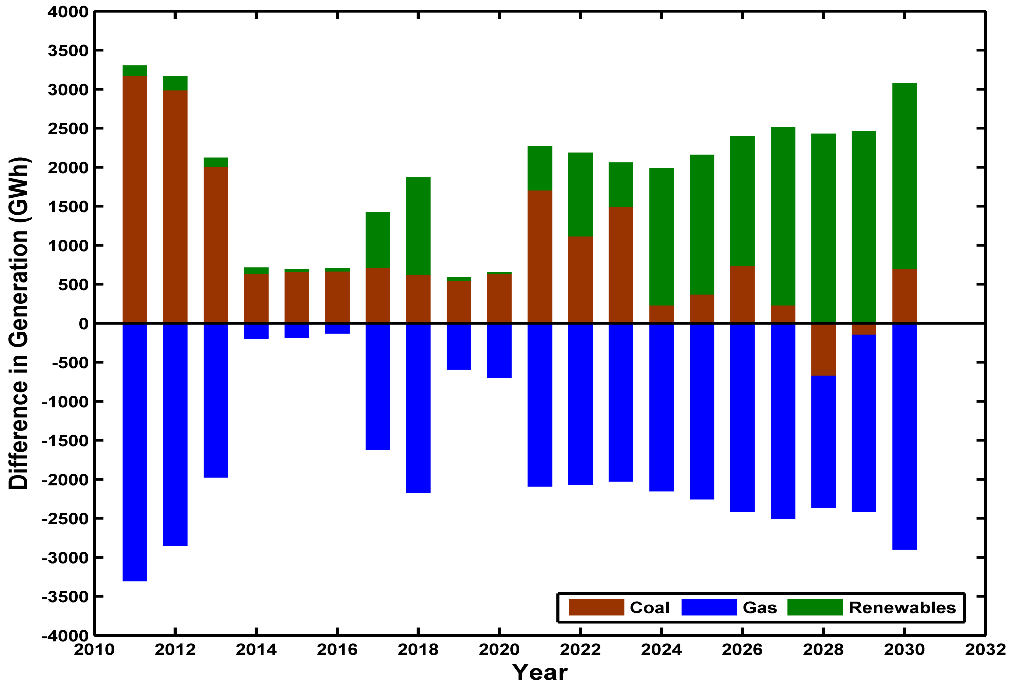

Figure 6.7 Difference in Generation in MC MDS resulting from Basslink's presence

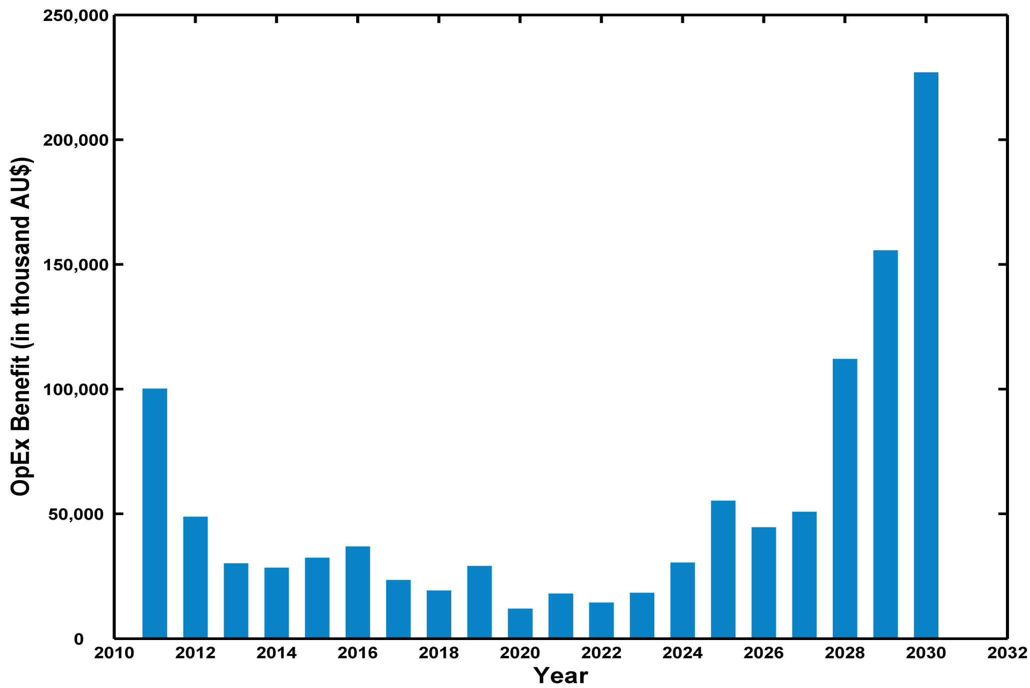

Figure 6.8 OpEx Benefit in SC MDS resulting from Basslink's presence

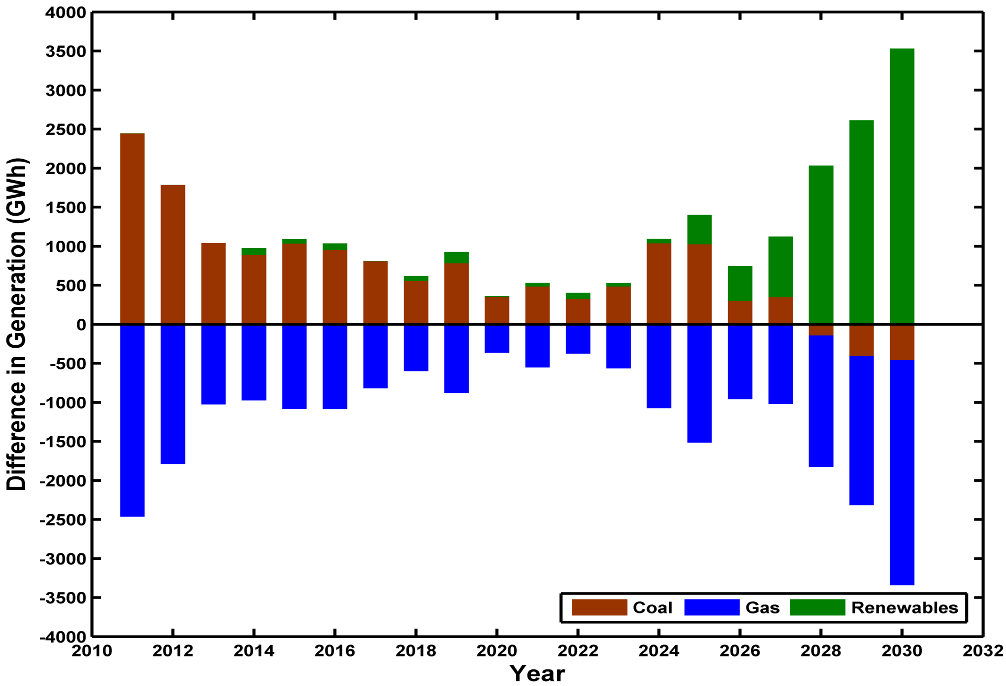

Figure 6.9 Difference in Generation in SC MDS resulting from Basslink's presence

6.3.1 General Commentary

To maintain the capacity adequacy each year, a minimum reserve level(MRL) specified for each individual region has to be met. In the NEM, this is specified annually for each region. Moreover, annual MRL values continue to increase over the years and are different in each MDS. Basslink enables a large firm hydro capacity (in Tasmania) that can provide support during peak hours in the NEM. Therefore, Basslink reduces the requirement for firm capacity, especially gas. In addition to its contribution for generation, the role of new gas capacity is extremely important in maintaining capacity adequacy. Moreover, such a capacity addition generally occurs in sizeable chunks due to integer nature of feasible builds. Such a trend is consistent among all three MDS.

In general, the addition of new renewable capacity in Basslink occurs to fulfil LRET requirements. Besides scheduled retirements, economic retirements of coal capacity strongly depend on carbon prices. High coal capacity retirement is observed in FC MDS. In FC MDS, installed capacities of gas and renewables are the highest among three MDS.

6.3.1.1 Installed Capacity Trend in FC MDS

The trends of installed capacity (in MW) in FC MDS with and without Basslink are shown in figure 6.10. Coal capacity diminishes over the years as the economic and scheduled retirements of coal plants take place. In the middle of the planning horizon, there is a significant retirement of coal plants, which is counterbalanced by a rise in new gas technologies.

The shortfall in the installed capacity created by the retirement of coal plants is met mainly by new gas technologies. By 2019, gas capacity surpasses coal capacity. Similarly, renewable capacity also progressively rises and exceeds coal capacity in the later years of the planning horizon.

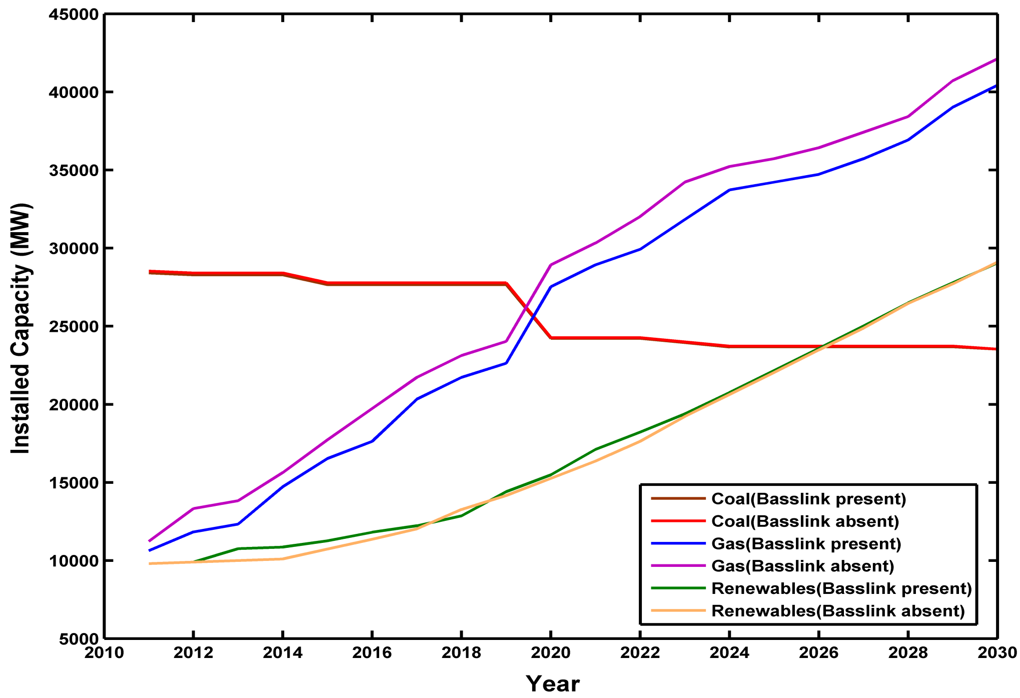

Figure 6.10 Installed Capacity in FC MDS

6.3.1.2 Installed Capacity Trend in MC MDS

Figure 6.11 shows the trends of installed capacity in MC MDS with and without Basslink. Though coal capacity slightly falls during some initial and later years, it remains mostly the same throughout the significant part of the planning horizon. Gas capacity rises progressively over the years. This leads to gas capacity exceeding coal capacity by 2026. Renewable capacity also rises (rising very slowly for a few years) but remains lower than that of coal and gas.

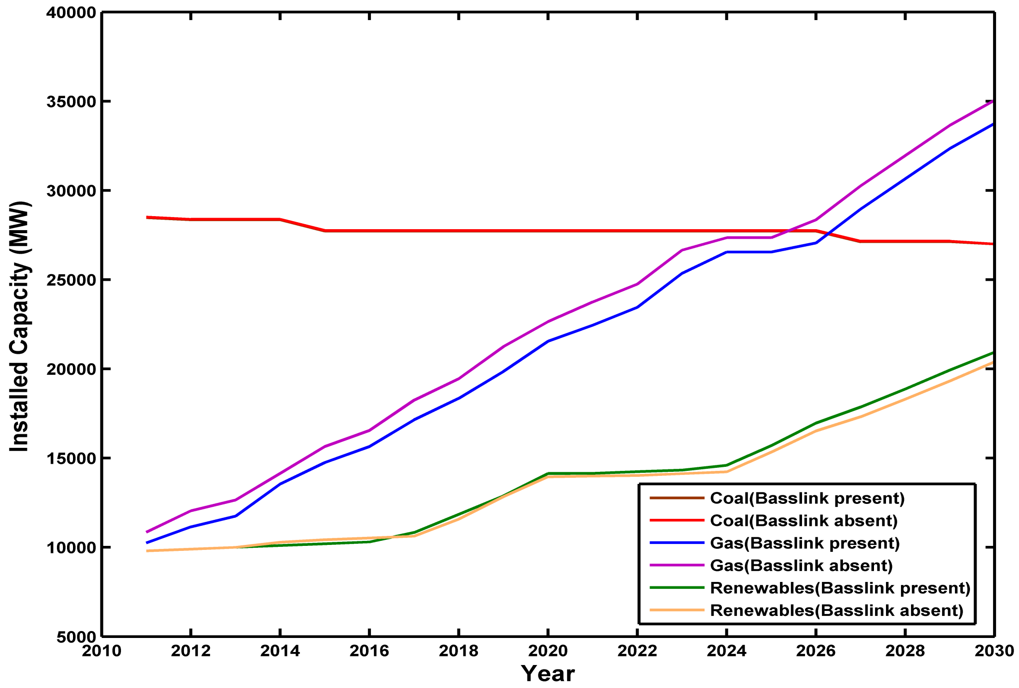

Figure 6.11 Installed Capacity in MC MDS

6.3.1.3 Installed Capacity Trend in SC MDS

The trends of installed capacity with and without Basslink in SC MDS are shown in figure 6.12. Among three MDS, the retirement of coal capacity in SC MDS is the slowest and least. At the end of the planning horizon, the installed coal capacity still remains higher than that of gas and renewables. Gas capacity rises progressively over the years. Barring a slightly sharp rise for a few years in the middle of the planning horizon, renewable capacity rises very slowly over the years and remains lower than that of coal and gas.

6.4 SCENARIO-WISE ANALYSIS AND COMMENTARY ON CAPEX BENEFIT

Annual CapEx benefit is the avoided CapEx in a year, i.e. savings in annualised build and fixed operation and maintenance (FOM) costs in a year. Annual CapEx benefit attributable to Basslink depends upon its ability to defer the addition of new generation, namely gas and renewables each year. Moreover, the variation in CapEx benefit over the years is also affected by the type of new generation as the build cost of renewables are significantly higher than that of gas. This section point out the CapEx benefits that can be attributed to Basslink over the 20-year planning period.

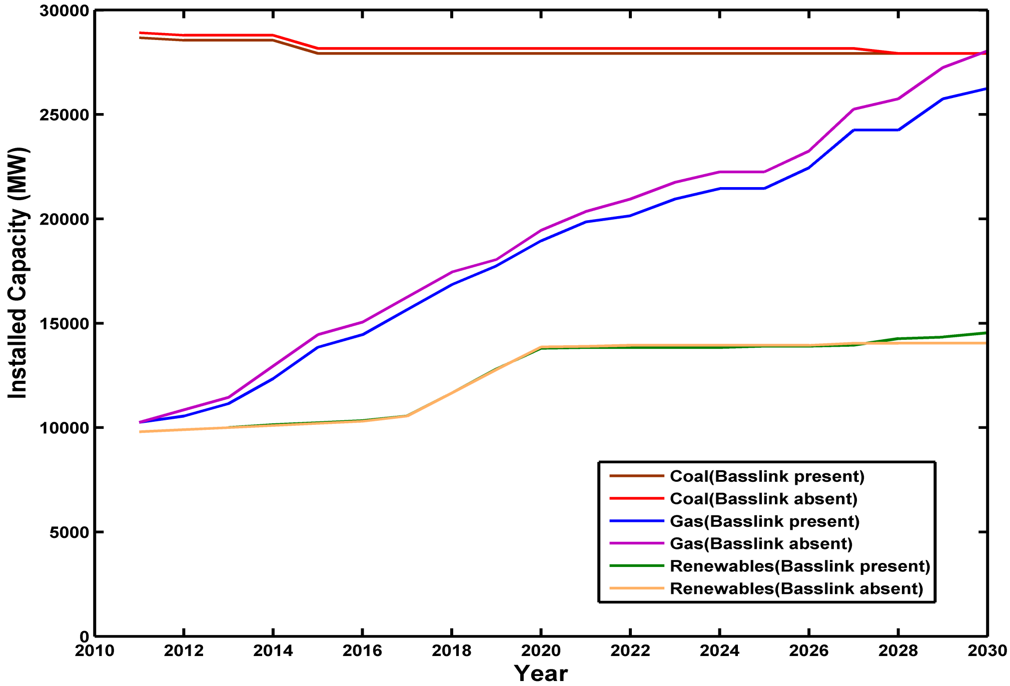

Figure 6.12 Installed Capacity in SC MDS

6.4.1 Commentary on CapEx Benefit in FC MDS

CapEx benefit and the difference in the installed capacity in FC MDS are as shown in figures 6.13 and 6.14 respectively. Basslink consistently lowers the addition of new gas capacity, which results in a CapEx benefit. Also, CapEx benefit is high in a year when Basslink reduces the addition of renewables as well as gas capacity. However, when Basslink facilitates the entry of significant amount of renewables, CapEx benefit is substantially reduced due to high build cost of renewables. This lowers the CapEx benefit, which even goes negative in years when there is large renewable build. The years 2013, 2014 and 2021 show significant CapEx. However, figure 6.4 shows the resultant OpEx gain in those years is greater than the CapEx.

6.4.2 Commentary on CapEx Benefit in MC MDS

Figures 6.15 and 6.16 show CapEx benefit and the difference in the installed capacity in MC MDS. In MC MDS too, Basslink lowers the addition of new gas capacity over the years. This results in the CapEx benefit. When Basslink occasionally defers the addition of renewables as well as gas, CapEx benefit becomes high. When Basslink attracts more renewables. CapEx benefit is significantly reduced and becomes even negative for some years. In particular, in 2024 and beyond, significant build of renewable capacity results in an increased CapEx. However,

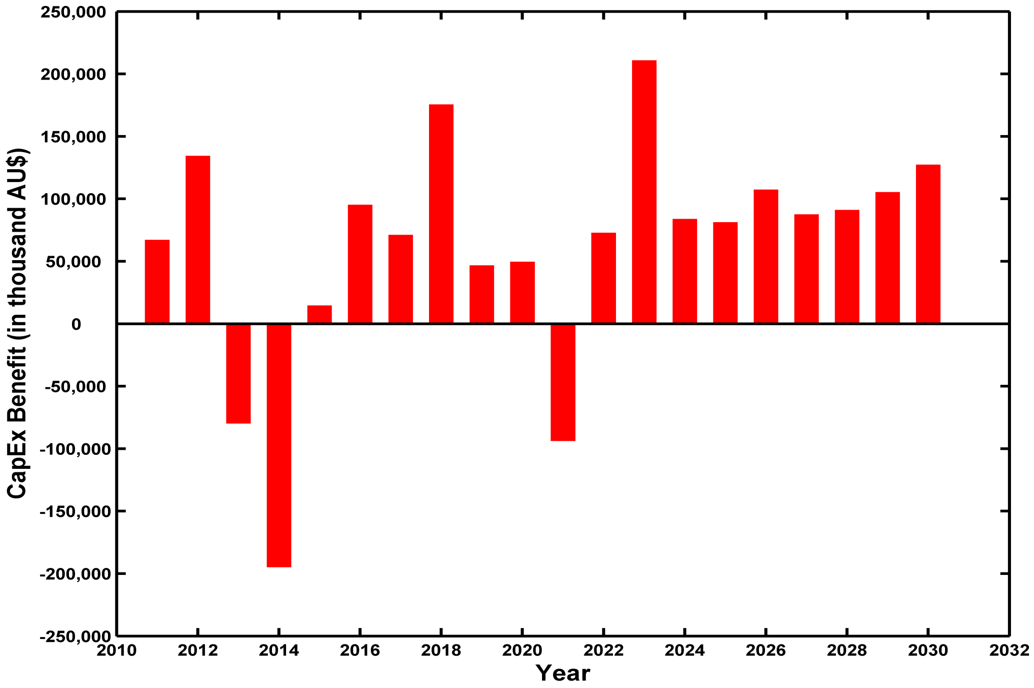

Figure 6.13 CapEx Benefit in FC MDS resulting from Basslink's presence

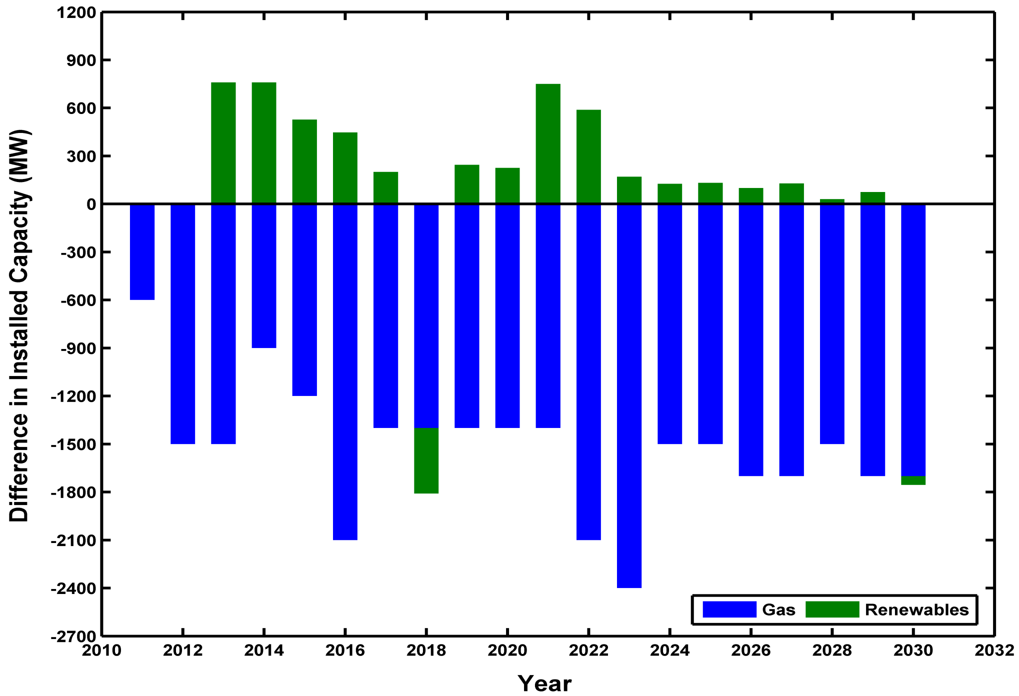

Figure 6.14 Difference in Installed Capacity in FC MDS resulting from Basslink's presence

figure 6.6 shows that OpEx gain in these years is greater than the CapEx.

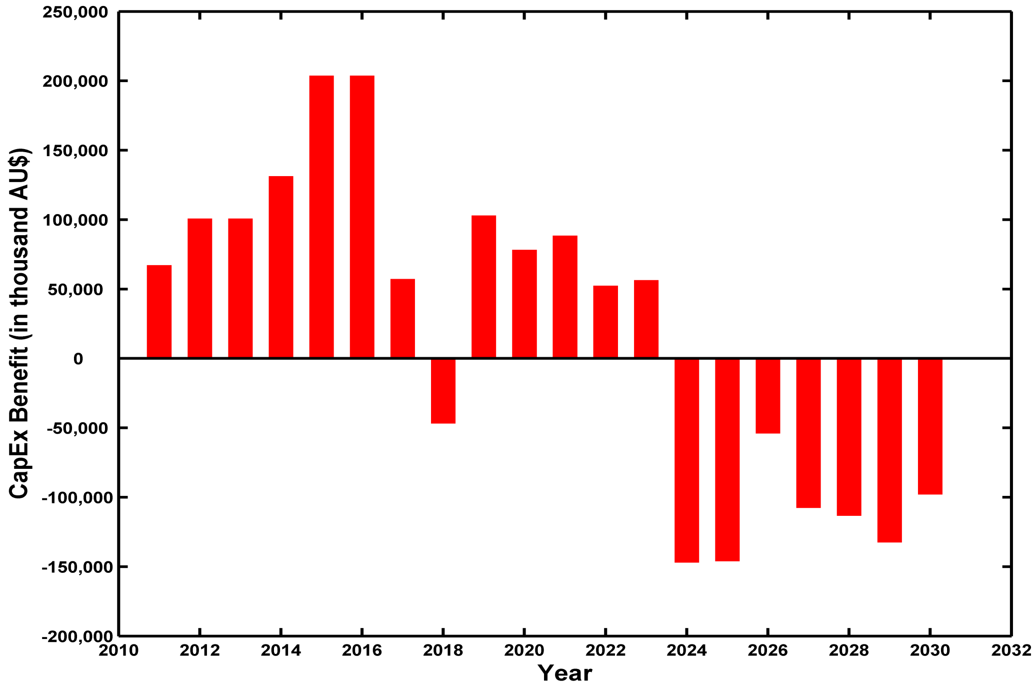

Figure 6.15 CapEx Benefit in MC MDS resulting from Basslink's presence

6.4.3 Commentary on CapEx Benefit in SC MDS

In SC MDS too, Basslink lowers the addition of new gas capacity over the years. This results in a CapEx benefit. In SC MDS, Basslink, in general, does not attract more renewables (except at the end years of the planning horizon) as it does in FC and MC MDS. CapEx benefit therefore remains consistently positive and high over the years until the end year. Figures 6.17 and 6.18 depict CapEx benefit and the difference in the installed capacity in SC MDS respectively.

6.5 COMMENTARY ON UNSERVED ENERGY TREND

This section discusses scenario-wise unserved energy trends.

6.5.1 General Commentary

In each MDS, demand, availability of generation resources and capacity reserves to be held in each year are precisely known. When sufficient generation resources are built, it can ensure

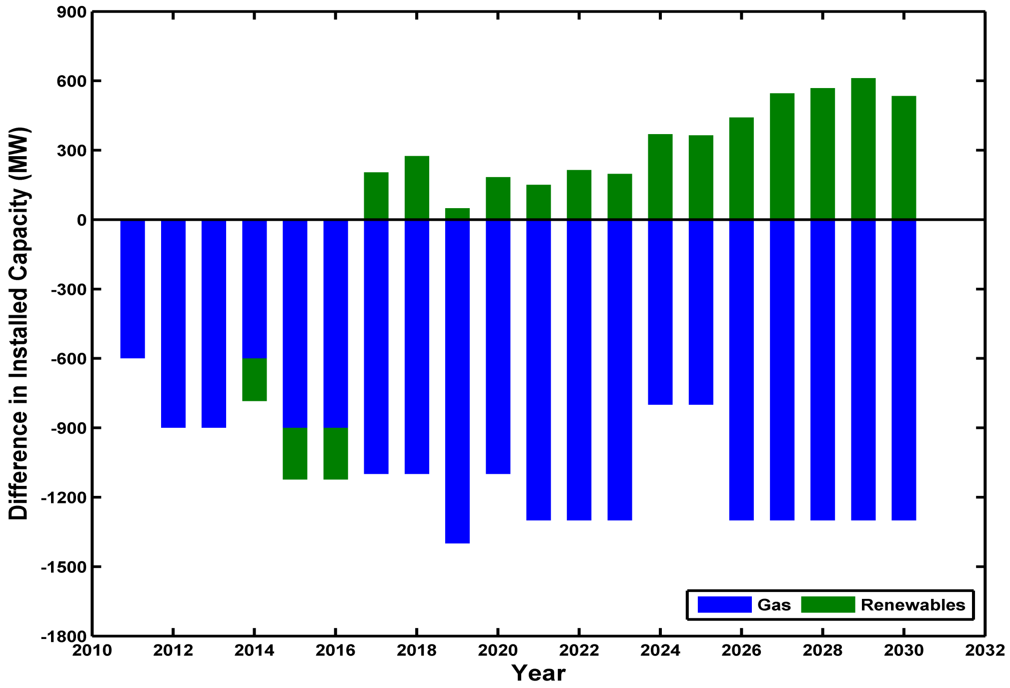

Figure 6.16 Difference in Installed Capacity in MC MDS resulting from Basslink's presence

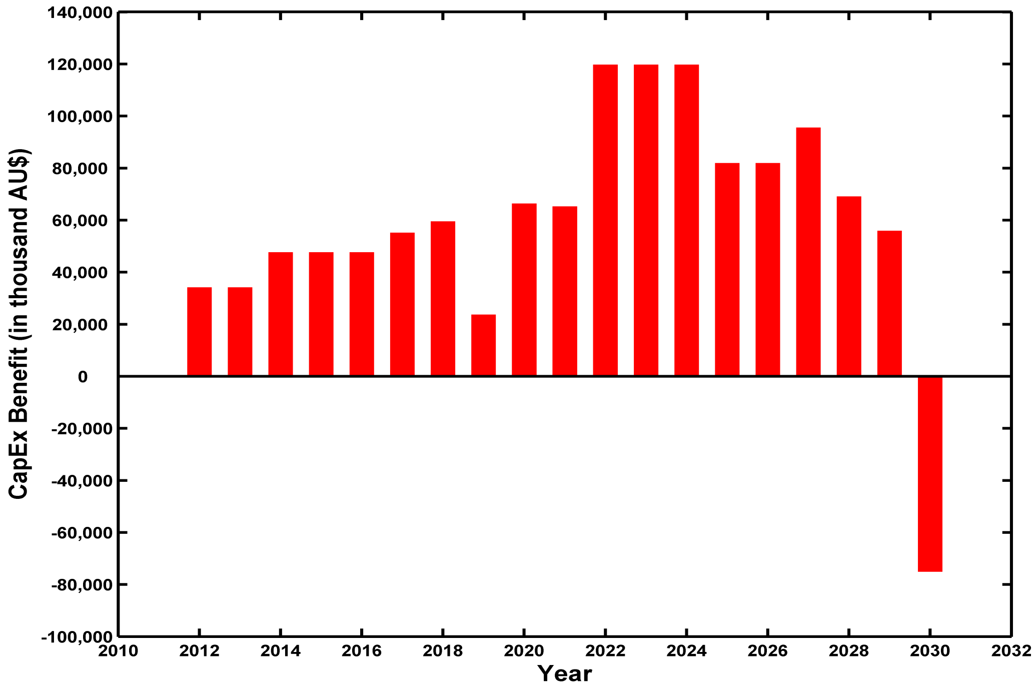

Figure 6.17 CapEx Benefit in SC MDS resulting from Basslink's presence

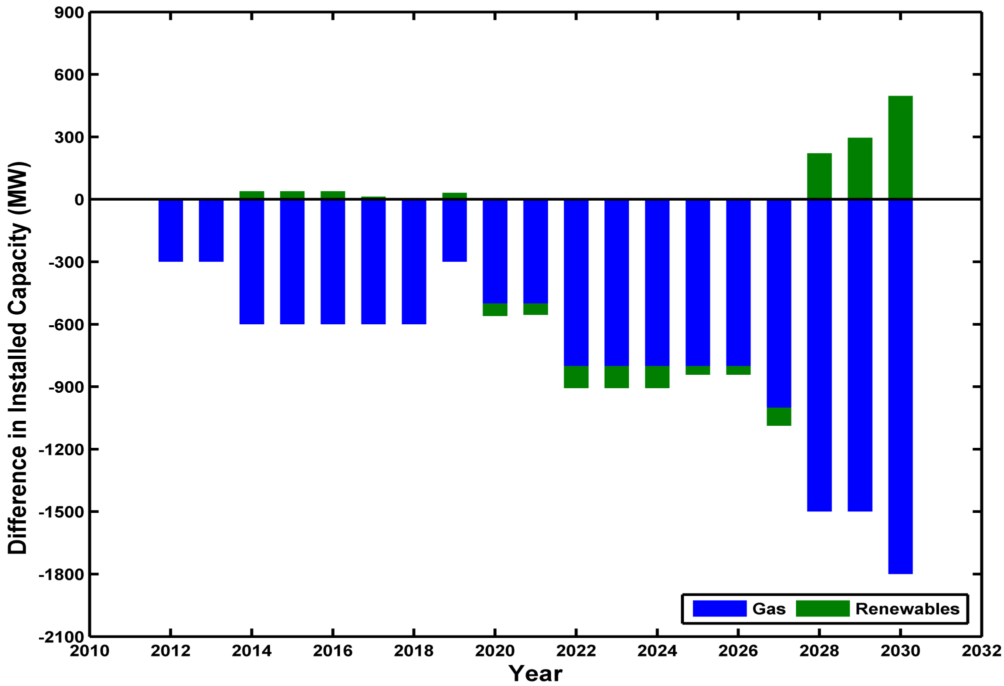

Figure 6.18 Difference in Installed Capacity in SC MDS resulting from Basslink's presence

increased reliability minimising the impacts of forced and maintenance outages in the system. USE is expected to occur when there are insufficient generation resources. In the NEM, USE is required to be less than 0.002% of total energy each year [47]. According to this standard, maximum allowable USE for each year is about 4 GWh.

In order to maintain capacity adequacy in the NEM, annual MRL are to be satisfied. Therefore, there is enough generation built and available each year taking into account the increase in demand and plant retirements. This ensures that a sufficient reserve margin is available each year, which substantially reduces the events of significant USE occurring in the NEM. In each MDS, annual USE is found consistently well below this limit with Basslink and without Basslink. Hence, the differential USE (USE without Basslink - USE with Basslink) in each year is nominal.

Figures 6.19, 6.20 and 6.21 show USE (mean values) trends in FC, MC and SC MDS respectively. In all MDS, USE (even the USE spikes in some years) is significantly below the maximum allowable limit in the NEM. In all MDS, the difference in USE lowers even further as year progresses. This is because the addition of sufficient capacity over the years strengthens the required capacity adequacy and ensures that reserve margin is available to avoid USE occurrences.

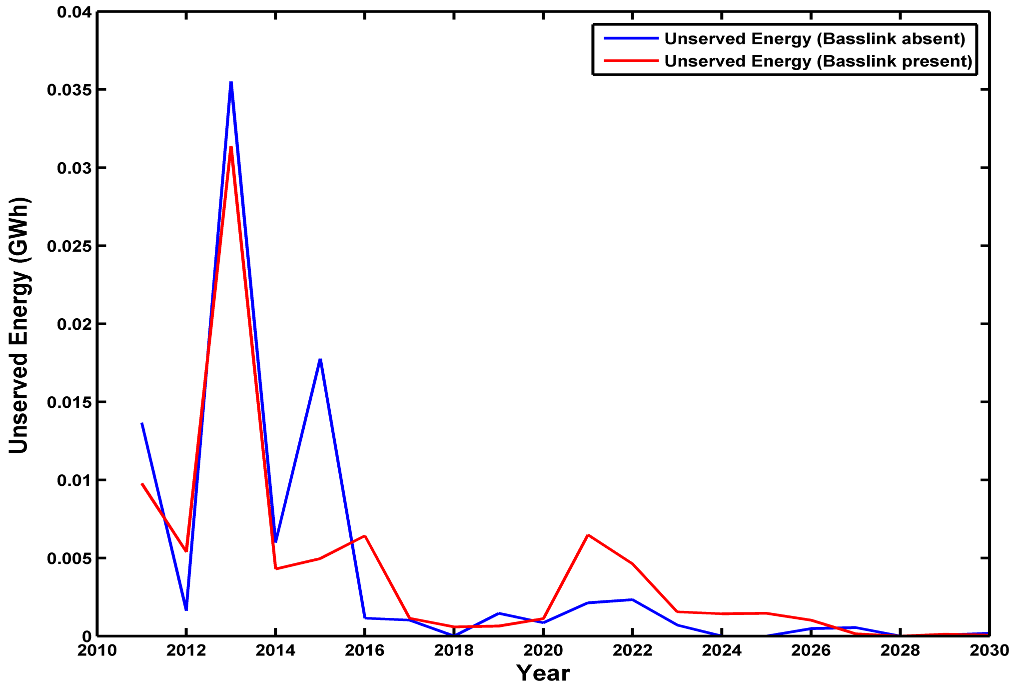

Figure 6.19 Unserved Energy in FC MDS

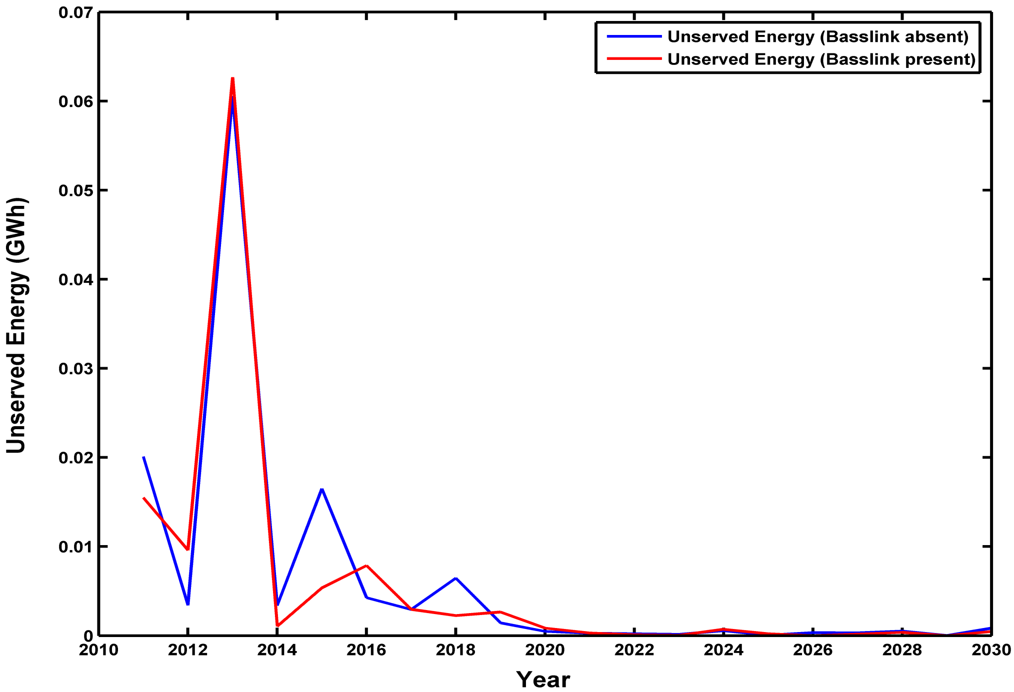

Figure 6.20 Unserved Energy in MC MDS

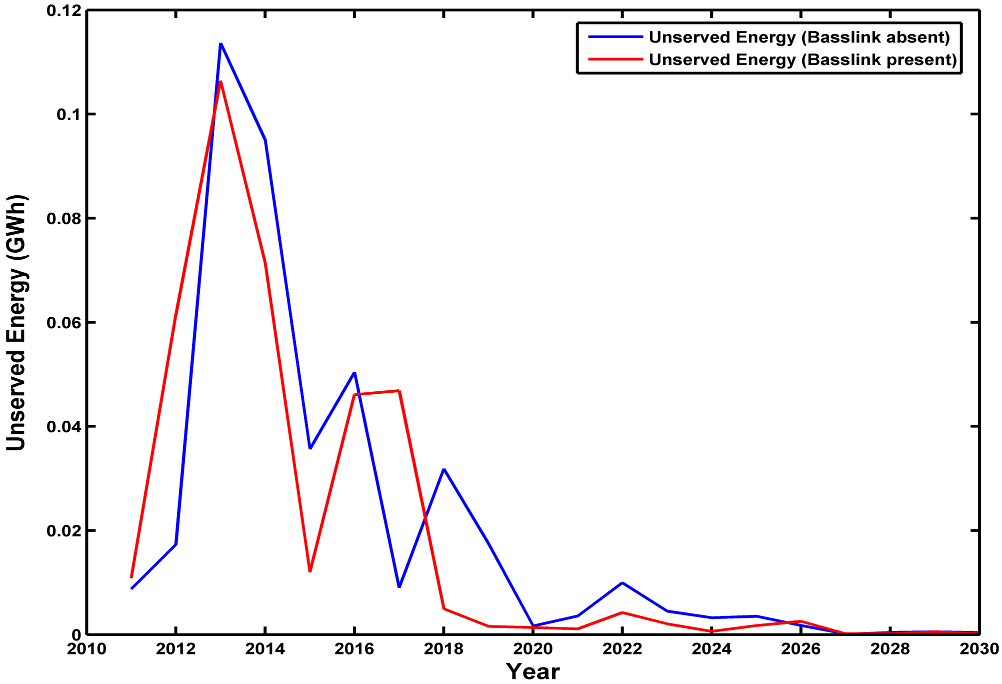

Figure 6.21 Unserved Energy in SC MDS

6.6 QUANTIFICATION OF MARKET BENEFITS AND ECONOMIC ANALYSIS

Tables 6.1 and 6.2 depict summary of market benefits attributable to Basslink until its economic life (2011-2050) in three MDS. All benefits are in real (undiscounted) thousand AU$ terms.

6.6.1 Trend of Scenario-wise Market Benefits

Figures 6.22, 6.23 and 6.24 present the variations of OpEx and CapEx benefits over the years of planning horizon in FC, MC and SC MDS respectively. Generally, there is a trade-off between OpEx and CapEx benefits over the years of planning horizon in each MDS [10], [15]. Whenever OpEx benefit is high, CapEx benefit goes down and becomes even negative for years when OpEx benefit is high. On the other hand, the magnitude of OpEx benefit lowers with a relative rise in CapEx benefit or even becomes negative for years when there is a high CapEx benefit. The rise in OpEx benefit in a particular year compensates the loss in CapEx benefit in that particular year and vice-versa.

The trade-off between OpEx and CapEx benefits can be explained on the basis of Basslink lessening dependence on gas generation (including expensive peaking gas generators) in the NEM. This leads to an OpEx benefit, which increases significantly when Basslink reduces generation

Table 6.1 Annual OpEx and CapEx Benefits (in thousand AU$)

Year	FC MDS		MC MDS		SC MDS	
	OpEx Benefit	CapEx Benefit	OpEx Benefit	CapEx Benefit	OpEx Benefit	CapEx Benefit
2011	210176	67200	166289	67200	100242	0
2012	116738	134400	102054	100800	48880	34200
2013	227819	-79883	76161	100800	30205	34200
2014	277648	-194983	-20335	131288	28427	47694
2015	111086	14709	-33062	203739	32408	47694
2016	65007	95209	-35433	203739	36975	47694
2017	53895	71158	50680	57209	23522	55214
2018	-94882	175601	97961	-46895	19326	59534
2019	76337	46717	3994	102973	29162	23698
2020	70305	49754	8445	78275	12042	66432
2021	230067	-93878	17864	88533	18116	65308
2022	-88984	72885	64267	52382	14504	119780
2023	-179844	210878	34358	56409	18420	119780
2024	35463	83945	159108	-147090	30510	119780
2025	47703	81373	161022	-146182	55289	81965
2026	92623	107477	130265	-54178	44623	81965
2027	112557	87584	179976	-107747	50862	95586
2028	53813	91171	187145	-113355	112134	69152
2029	89240	105484	204876	-132650	155669	55908
2030	58150	127428	186594	-98076	227006	-75103
2031	58150	127428	186594	-98076	227006	-75103
2032	58150	127428	186594	-98076	227006	-75103
2033	58150	127428	186594	-98076	227006	-75103
2034	58150	127428	186594	-98076	227006	-75103
2035	58150	127428	186594	-98076	227006	-75103
2036	58150	127428	186594	-98076	227006	-75103
2037	58150	127428	186594	-98076	227006	-75103
2038	58150	127428	186594	-98076	227006	-75103
2039	58150	127428	186594	-98076	227006	-75103
2040	58150	127428	186594	-98076	227006	-75103
2041	58150	127428	186594	-98076	227006	-75103
2042	58150	127428	186594	-98076	227006	-75103
2043	58150	127428	186594	-98076	227006	-75103
2044	58150	127428	186594	-98076	227006	-75103
2045	58150	127428	186594	-98076	227006	-75103
2046	58150	127428	186594	-98076	227006	-75103
2047	58150	127428	186594	-98076	227006	-75103
2048	58150	127428	186594	-98076	227006	-75103
2049	58150	127428	186594	-98076	227006	-75103
2050	58150	127428	186594	-98076	227006	-75103

Table 6.2 Annual Reliability Benefits (in thousand AU$)

Year	FC MDS	MC MDS	SC MDS
	Reliability Benefit	Reliability Benefit	Reliability Benefit
2011	49	58	-26
2012	-47	-77	-551
2013	52	-26	90
2014	21	29	296
2015	160	139	296
2016	-66	-45	54
2017	-2	0	-473
2018	-7	53	336
2019	10	-15	199
2020	-3	-5	4
2021	-54	0	31
2022	-29	1	72
2023	-11	1	30
2024	-18	-2	33
2025	-18	-2	22
2026	-7	4	-10
2027	5	2	0
2028	0	2	3
2029	-1	0	0
2030	2	5	3
2031	2	5	3
2032	2	5	3
2033	2	5	3
2034	2	5	3
2035	2	5	3
2036	2	5	3
2037	2	5	3
2038	2	5	3
2039	2	5	3
2040	2	5	3
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2043	2	5	3
2044	2	5	3
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2050	2	5	3

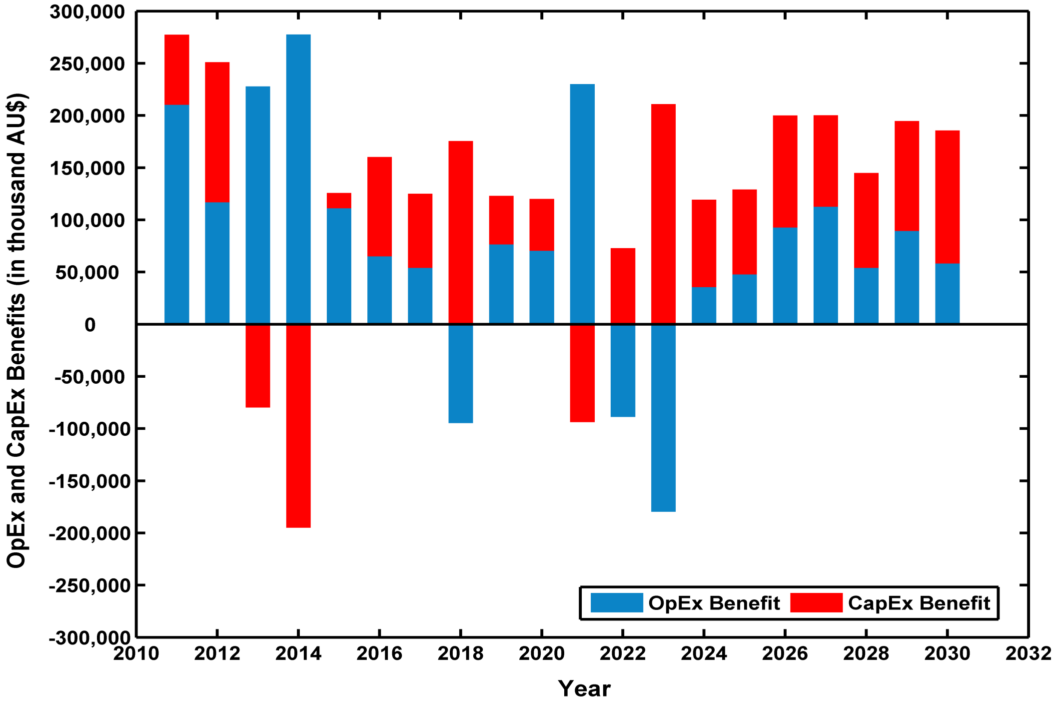

Figure 6.22 Annual OpEx and CapEx Benefits in FC MDS

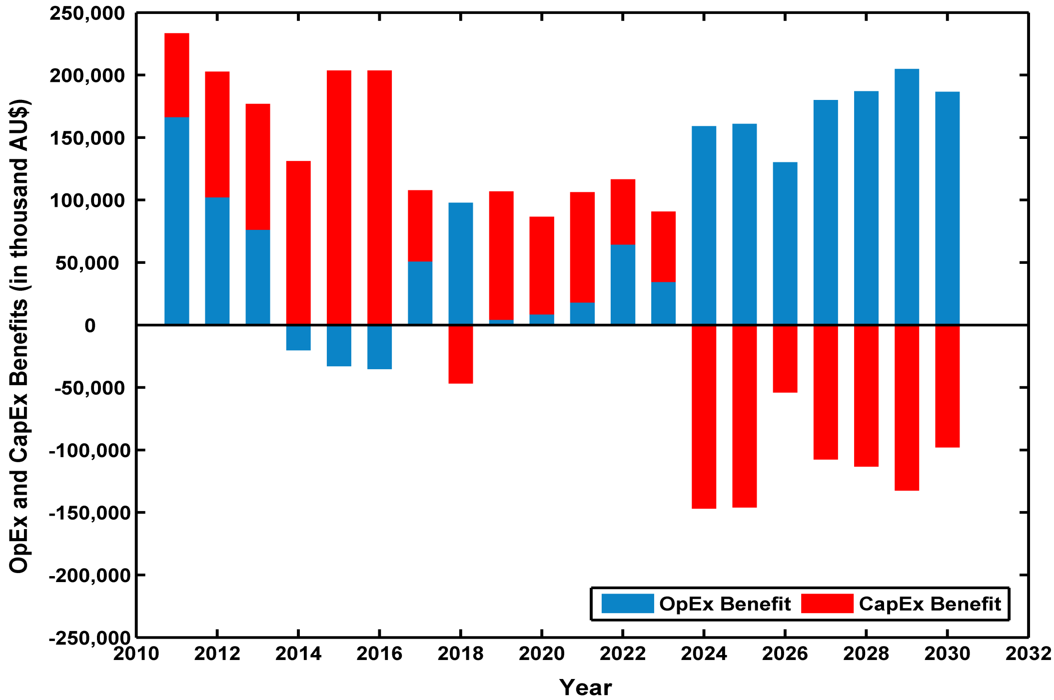

Figure 6.23 Annual OpEx and CapEx Benefits in MC MDS

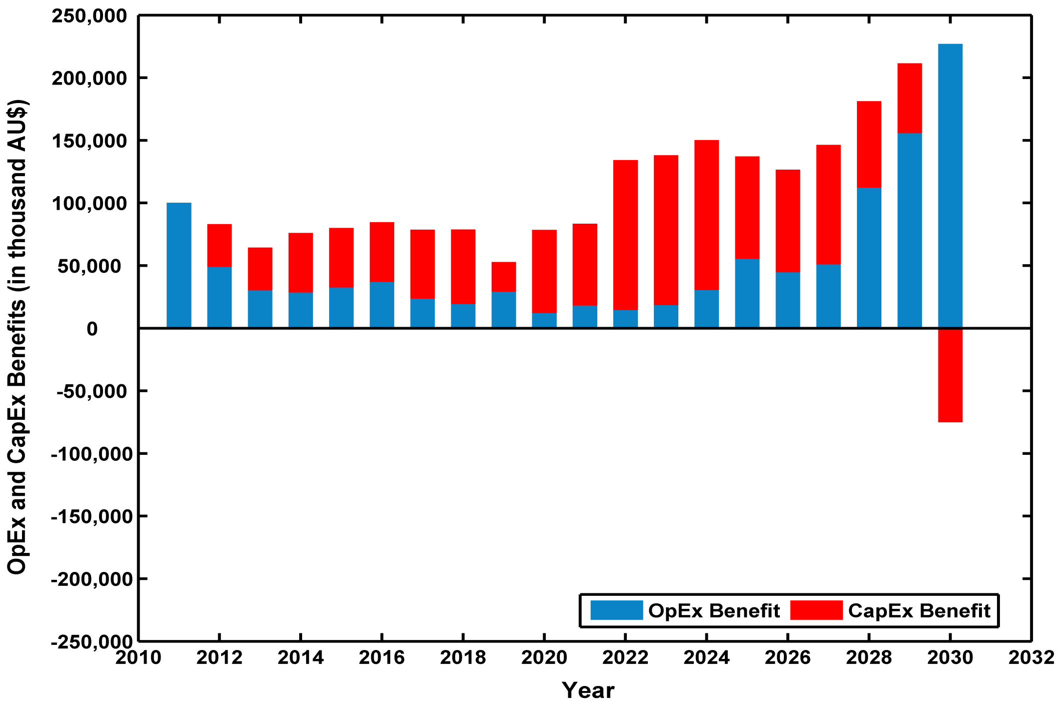

Figure 6.24 Annual OpEx and CapEx Benefits in SC MDS

from coal as well as gas. The CapEx benefit falls and even reaches negative in years when Basslink brings in expensive renewables in significant amount. Conversely, there is a significant CapEx benefit when Basslink lowers the addition of new capacity (in large chunks). In this case, OpEx benefit reduces as demand has to be met using existing generation sources more (including costly gas peakers). In each year, it is the overall combination of OpEx and CapEx benefits, which is optimized.

Each MDS has a unique pattern of OpEx and CapEx benefits variation over the planning horizon. Since the impact levels of key scenario drivers are much stronger in FC and MC MDS than those in SC MDS, it is observed that patterns of benefit trade-off are much sharper over the years in FC and MC MDS. SC MDS encounters relatively less sharp trade-off between benefits until the impact levels of key scenario drivers become more appreciable during the later years of the planning horizon. The underlying trend of such a trade-off is that OpEx and CapEx benefits vary almost in opposition over the years in all three MDS. The trend of benefit trade-off remains unique to a particular MDS.

Annual reliability benefit, however is significantly small compared to OpEx and CapEx benefits in each MDS.

6.6.2 Comparative Analysis of Market Benefits

Figures 6.25, 6.26 and 6.27 show total annual benefits attributable to Basslink in FC, MC and SC MDS respectively. Total annual benefit in each MDS includes OpEx, CapEx and reliability benefits.

In FC MDS, total annual benefits are higher in a few early and later years of the planning horizon. Even, smaller total annual benefits observed in FC MDS are generally of the similar magnitude when compared with higher total annual benefits of MC and SC MDS. Therefore, Basslink is capable of delivering the highest market benefit (in terms of NPV) in FC MDS among three.

Total annual benefits in MC MDS are higher in the beginning years but become smaller as year progresses. SC MDS sees total annual benefits getting higher in the later years of the planning horizon especially after 2021.

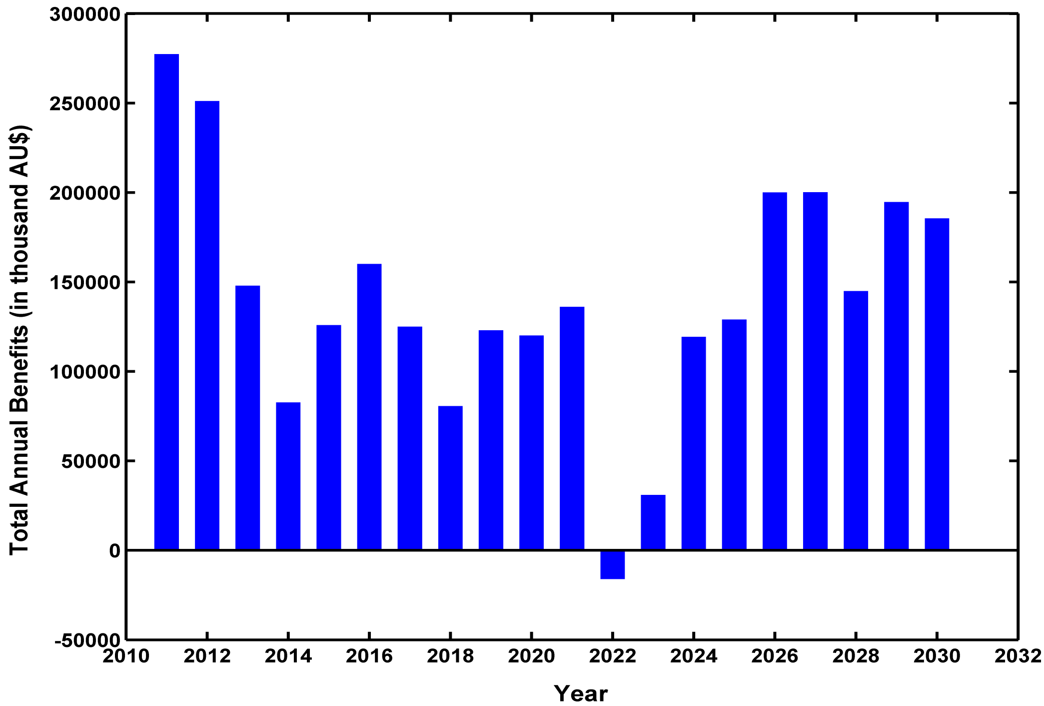

Figure 6.25 Total Annual Benefits in FC MDS

Table 6.3 shows the NPVs of respective benefits in three different MDS. NPV of these benefits (until the useful life of Basslink) are obtained, discounting each yearly benefit to the base year 2011. In FC MDS, the NPV of the total benefit attributable to Basslink is the highest among all three MDS.

The stronger the impacts of key scenario drivers, greater are the benefits. For example, average

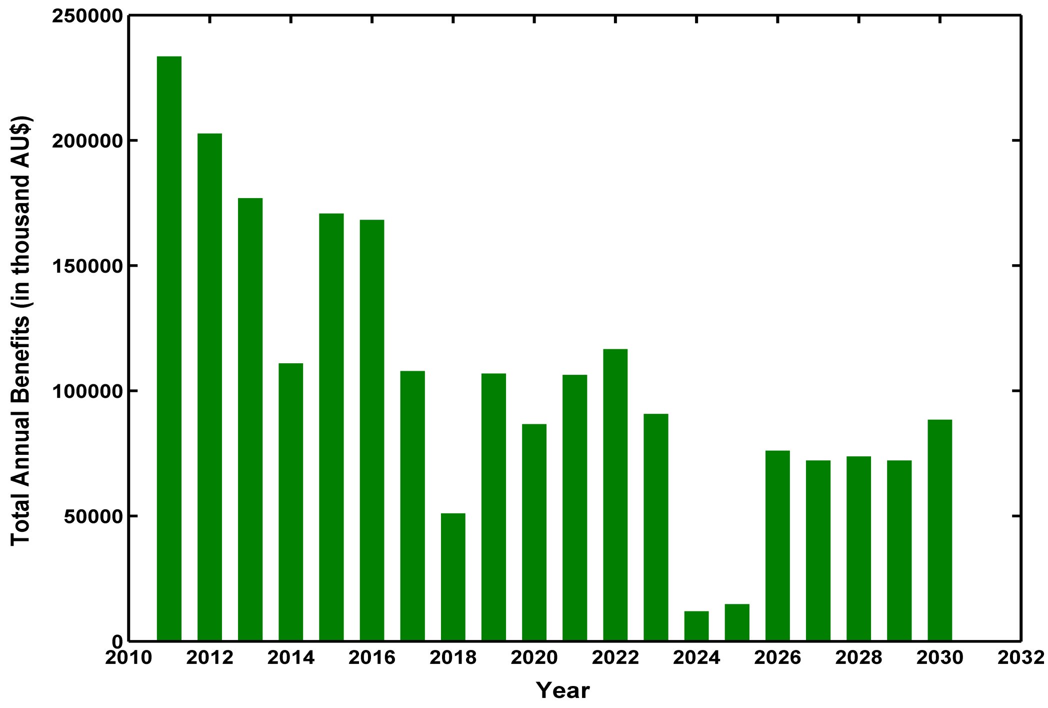

Figure 6.26 Total Annual Benefits in MC MDS

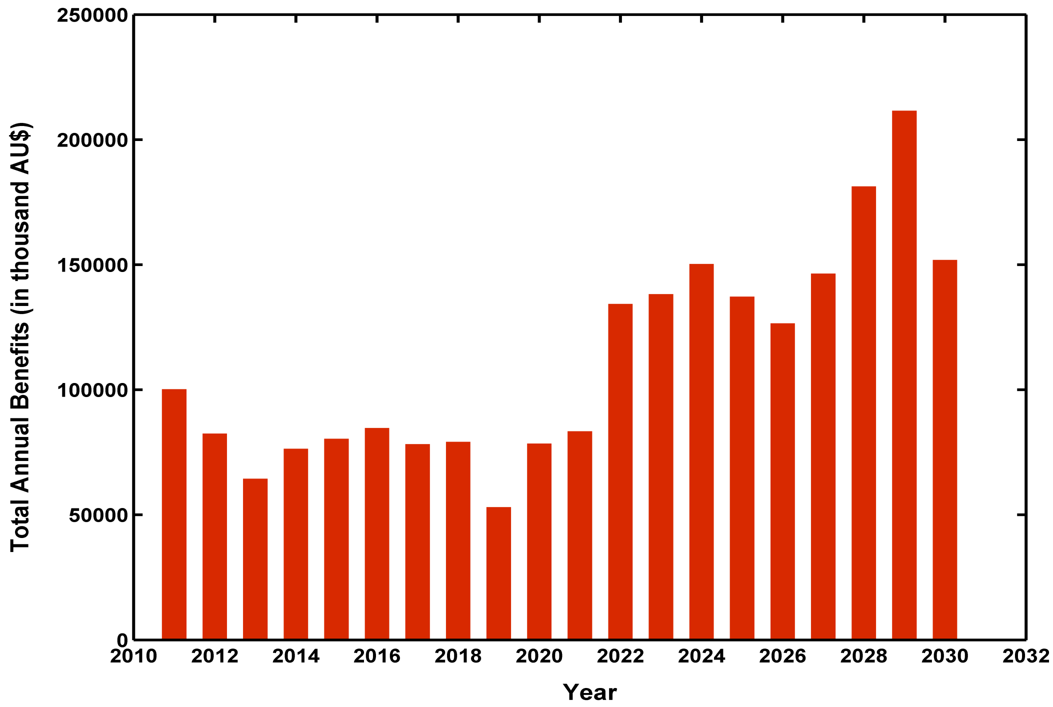

Figure 6.27 Total Annual Benefits in SC MDS

Table 6.3 Net Present Value of Market Benefits (in thousand AU$)

Type of Market Benefit	FC MDS	MC MDS	SC MDS
OpEx Benefit	1,063,445	909,801	744,384
CapEx Benefit	601,511	450,005	367,265
Reliability Benefit	89	81	69

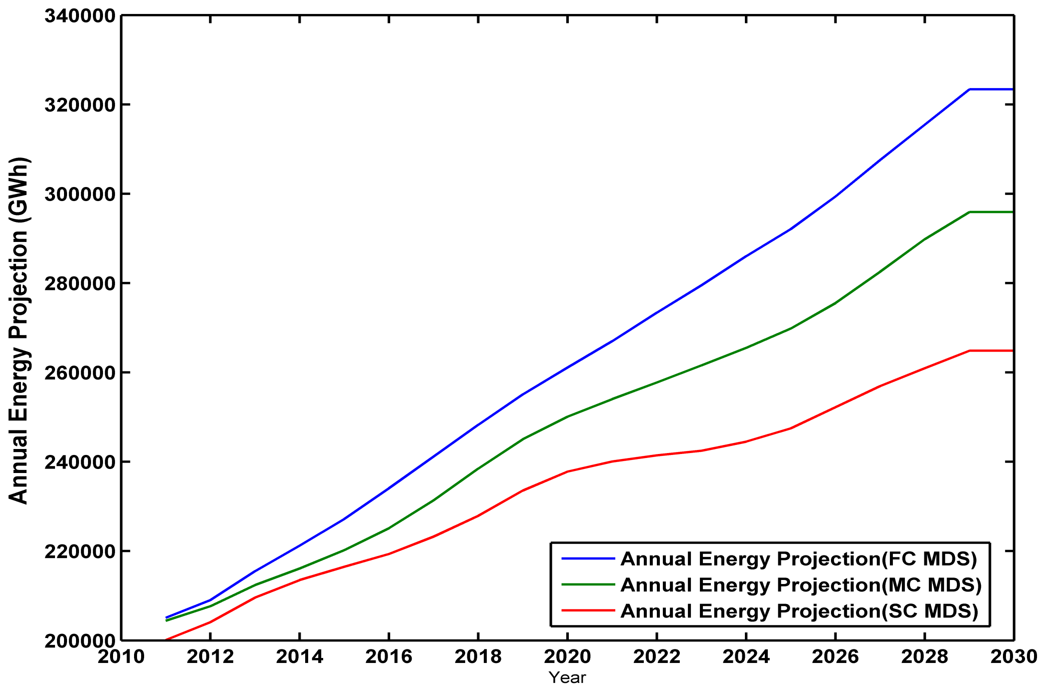

Figure 6.28 Annual Energy Projection

GWh demand (controlled by NEM dispatch process) for a 20-year planning horizon (2011-2030) is about 6% and 12% higher in FC MDS relative to MC and SC MDS respectively. Figure 6.28 shows annual energy projections (controlled by the NEM dispatch process) in FC, MC and SC MDS. Likewise, average carbon cost in FC MDS for a 20-year planning horizon (2011-2030) is about one and half and twice as much as relative to MC and SC MDS respectively. These have significant contribution on the increased OpEx benefit in FC MDS relative to MC and SC MDS. Figure 6.29 shows annual carbon costs (AU$/tonne CO_2-e) in FC, MC and SC MDS.

Figures 6.30 and 6.31 show average build costs of new entrant gas and renewable generation technology respectively in FC, MC and SC MDS. New gas technology has its average CapEx for a 20-year planning horizon is about 4% and 20% higher in FC MDS relative to MC and SC MDS. Similarly, average CapEx for a 20-year planning horizon of renewables is about 2% and 18% higher in FC MDS compared to MC and SC MDS. This contributes to higher CapEx

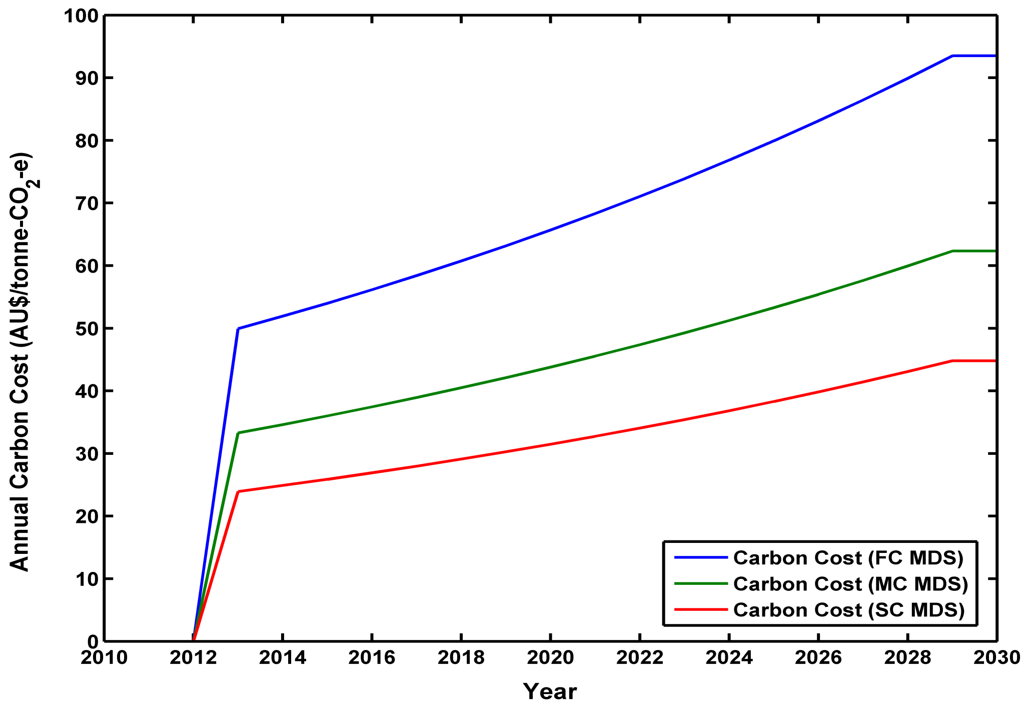

Figure 6.29 Annual Carbon Cost

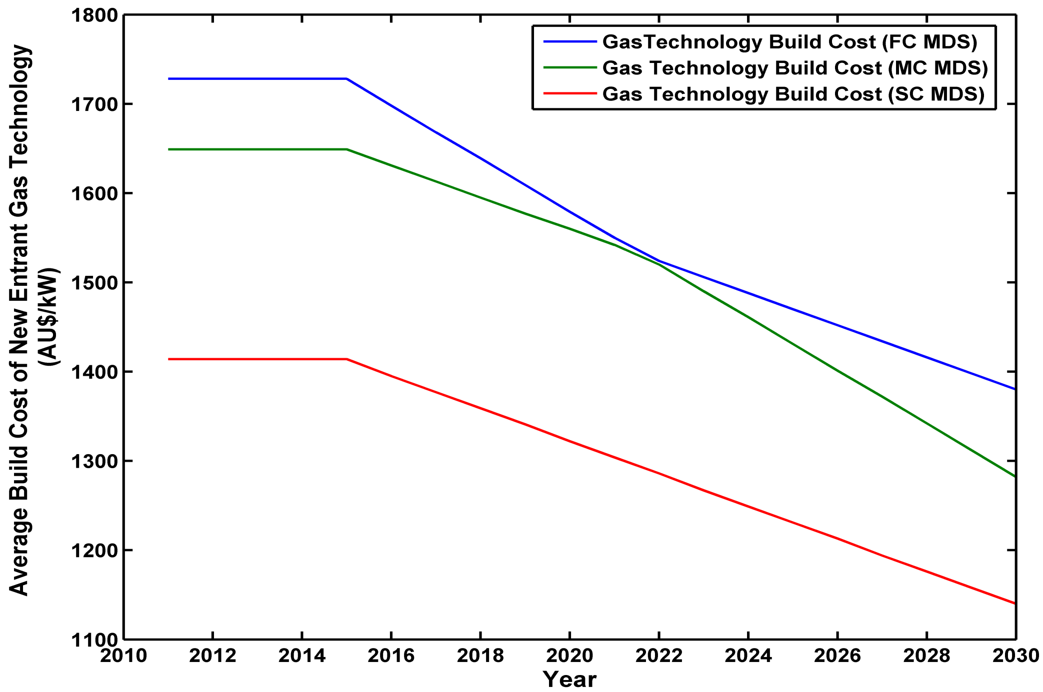

Figure 6.30 Average Build Cost of New Entrant Gas Technology

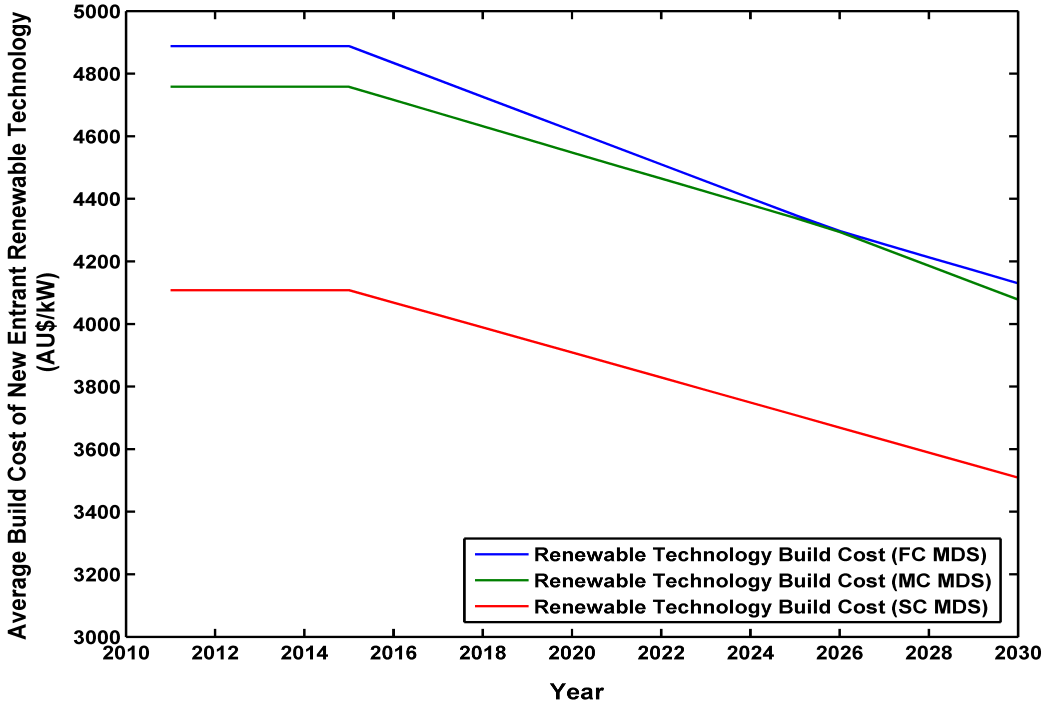

Figure 6.31 Average Build Cost of New Entrant Renewable Technology

benefit in FC MDS in comparison to MC and SC MDS. CapEx benefits would have been further inflated had new technology cost been higher.

The presence of Basslink in the NEM has economic significance in terms of market benefits as demonstrated by positive NPV of market benefits in all three MDS. In FC MDS, Basslink is able to deliver relatively higher benefits (in terms of NPVs of respective benefits), which reduce for the MC and SC MDS. Even though demand-supply situation in the NEM has changed remarkably since the original idea of Basslink was conceived in early eighties, Basslink continues to be of economic value for the ranges of MDS studied. The less carbon intensive the Australian electricity sector is, more significant the economic value of Basslink becomes. With rising carbon prices and demand, it continues to become even more valuable.

Chapter 7

CONCLUSIONS AND FUTURE WORK

7.1 CONCLUSION

A transmission IC delivers economic benefits to the electricity market comprising of various market participants (consumer, producer and transporter). These economic benefits attributable a transmission IC are also referred to as market benefits. Assessment of market benefits constitutes one of the essential components of regulatory requirements of transmission economic benefit assessment methodology.

Assessment of the long term market benefits attributable to Basslink in the Australian NEM in different MDS is the major contribution made by the research presented in this thesis. In consistence with AER devised RIT-T framework, a long term market benefit assessment framework is developed to estimate three market benefits, namely OpEx, CapEx and USE (reliability) attributable to Basslink. Based on this, a long term market benefit modelling framework is devised to assess these market benefits in three different MDS. Key scenario drivers include demand, carbon costs, fuel prices and new generation technology costs. The long term market benefit modelling framework comprises three essential steps which are LCM, TSM and EA. Using this modelling framework, a detailed modelling set-up is created in PLEXOS, a leading power market modelling tool. LCM and TSM are undertaken making use of the integrated simulation suites (LT Plan-MT-ST) in PLEXOS. Considering two distinct cases (Basslink present and absent) in the modelling set-up, LCM and TSM are carried out for each of them. In each MDS, LCM provides respective generator build schedule and CapEx for Basslink present and absent cases. Similarly, TSM gives respective amount of generation and OpEx in each MDS for Basslink present and absent cases. With a large number (2000 in our case) of samples using Monte Carlo technique in TSM, the amount of annual USE and the corresponding USE cost (priced at VoLL) are obtained for Basslink present and absent cases.

Scenario-wise modelling outputs, namely OpEx, CapEx and USE cost obtained from LCM and TSM runs for each year of the planning horizon are used for the detailed commentary and economic analysis of market benefits attributable to Basslink. Assuming the benefits at the end year of the planning horizon continuing until the useful life of Basslink, NPV of each type of market benefit is calculated by discounting yearly benefit to the base year of 2011 using a real discount rate of 10% for all MDS.

Generation trends in each MDS are studied. Among three MDS, coal based generation falls significantly in FC MDS with gas generation gradually rising to meet the shortfall. The fall in coal generation is relatively lower in MC MDS. However, coal continues to remain a dominant generation in SC MDS with its contribution rising over the years. Whenever there is a decrease in coal generation, gas generation rises to compensate the shortfall and vice-versa. Also, generation from renewables increases gradually (albeit slowly) to meet the mandatory annual LRET. In each MDS, generation trends (with and without Basslink) are similar, except that Basslink meets the respective demand by running consistently less gas based generation but more coal and renewable generation.

Similarly, the study of installed capacity trends in each MDS with and without Basslink is undertaken. The retirement (including fixed and scheduled retirements) of coal capacity is the highest in FC among three MDS. Coal retirements further lower in MC and SC MDS. Due to its high firm capacity of gas based generation, installed gas capacity in all MDS rises progressively over the years to maintain the required capacity reserve margin as well as to meet the shortfall from coal retirements. Installed renewable capacity also rises over the years. More new entrant gas and renewables enter in FC MDS. Their entry, however gradually lowers in MC and SC MDS. In each MDS, installed capacity trends (with and without Basslink) are similar, except that Basslink consistently lessens the entry of new entrant gas capacity and also renewables in some years.

Since the magnitudes of annual generation and installed capacity in the absence of Basslink are different from those when Basslink is present, this leads to differences in annual OpEx and CapEx respectively in each MDS. This results in annual OpEx and CapEx benefits, which can be either positive or negative for a year. It is also observed that there exists a trade-off between OpEx and CapEx benefits over the years of planning horizon in each MDS. Low CapEx benefit (even negative for some years) is offset by high OpEx benefit in a year and vice-versa. Hence, OpEx and CapEx benefits vary almost in an opposite unison over the years in all three MDS. This trade-off between OpEx and CapEx benefits is strongly influenced by key scenario drivers. Therefore, OpEx and CapEx benefit trade-off trend is unique to a MDS. Due to a sufficiently high capacity reserve margin available annually in the NEM, the amount of annual USE in each year is found to be below maximum allowable USE limit, which indicates a high degree of reliability. Therefore, the differential USE in each year is minimal. The reliability benefit is small in comparison to OpEx and CapEx benefits.

EA concludes that NPVs of reliability benefit is positive in all MDS indicating that economic significance of Basslink in the NEM. Among three MDS, FC causes the highest benefits to accrue from Basslink, which gradually decreases in MC and SC. Although the demand-supply situation in the NEM has undergone significant change since Basslink was conceived, the research undertaken concludes that Basslink continues to be of economic value for the ranges of MDS studied. The less carbon intensive is the Australian electricity sector, the more worthy becomes Basslink.

7.2 FUTURE WORK

There are a few areas identified in this research for the further progress.

7.2.1 Transmission Network Constraints

The current research does not take into account generic and other applicable transmission network constraints in the NEM for the modelling. Incorporating these transmission network constraints in the modelling will be a better representation of the NEM transmission system and will provide more refined modelling outcome. However, the trade-off will be increased computational time to obtain the optimal (best integer) solution.

7.2.2 Hydro Energy Constraints

Barring small hydro systems whose impact would not be much significant, another area of further refinement may be the maximum annual energy (in GWh) constraints of big hydro schemes such as Snowy, Tasmanian for each year of the planning horizon depending on the availability of forecast. The current research assumes a constant maximum annual energy constraint for these big hydro schemes over the years of the planning horizon.

7.2.3 Transmission Setup in TSM run

The current research assumes regional transmission setup for both LCM and TSM. Though regional set-up is reasonably better approximation of the NEM for LCM involving a long planning horizon, it is a better proposition to assume a more detailed transmission set-up, i.e. nodal for TSM, which has a yearly time horizon. Nodal transmission set-up includes intra-regional transmission lines in addition to inter-regional transmission ICs and is a detailed representation of the NEM transmission system. However, the trade-off may be the increased computational time.

7.2.4 LDC Blocks

One LDC with 8 blocks on a monthly basis is used in approximating hourly load profiles for each year of the planning horizon in LCM. Increasing number of load blocks may result in even better approximation of load profiles in LCM. However, the trade off is the computational time.

7.2.5 Modelling Other Market Benefits

In this research, only three types of market benefits are modelled assuming market under perfect competition. A significant contribution can be made by modelling other key market benefits such as competition benefit.

7.2.6 Sensitivity Analysis

Sensitivity analysis can be another interesting issue, undertaken by observing the changes in the magnitudes of different market benefits with corresponding changes in varying key parameters. These include parameters such as discount rate, zero carbon price etc.

Appendix A

EXISTING GENERATOR CHARACTERISTICS

This appendix contains some important technical data of existing generators in the NEM.

Table A.1: Existing Generator Characteristics

Station Name	State	Capacity (MW)	Heat Rate (GJ/MWh)	Auxiliaries (%)	FOM Cost (AU$/MW/year)	VOM Cost (AU$/MWh)	Combustion Emission Factor	Fugitive Emission Factor	FOR (%)	MOR (%)
Bayswater	NSW	2720	10.03	6	49000	1.19	90.2	8.7	6	4
Blowering	NSW	80	-	1	52000	6.15	0.0	0.0	0	4
Colongra GT	NSW	664	11.25	3	13000	9.98	51.3	14.2	1.5	0
Eraring	NSW	2798	10.17	6.5	49000	1.19	89.5	8.7	6	4
Guthega	NSW	60	-	1	52000	6.15	0.0	0.0	0	4
Hume (NSW)	NSW	29	-	1	52000	7.15	0.0	0.0	0	4
Hunter Valley	NSW	50	12.86	3	13000	9.61	69.7	5.3	2.5	0
Liddell	NSW	2100	10.65	5	52000	1.19	92.8	8.7	6	8
Mt Piper	NSW	1320	9.73	5	49000	1.32	87.4	8.7	6	4
Munmorah	NSW	600	11.69	7.3	55000	1.19	90.3	8.7	10	4
Redbank	NSW	150	12.29	8	49500	1.19	90.0	8.7	7	4
Shoalhaven	NSW	240	-	1	52000	7.15	0.0	0.0	0	4
Smithfield	NSW	176	8.78	5	25000	2.40	51.3	14.2	2.5	2
Tallawarra	NSW	410	7.2	3	31000	1.05	51.3	14.2	3	2
Tumut 1	NSW	330	-	1	52000	6.15	0.0	0.0	0	4
Tumut 2	NSW	286	-	1	52000	6.15	0.0	0.0	0	4
Tumut 3	NSW	1500	-	1	52000	6.15	0.0	0.0	0	4
Uranquinty	NSW	664	11.25	3	13000	9.98	51.3	14.2	1.5	0
Vales Point B	NSW	1320	10.17	4.6	49000	1.19	89.8	8.7	6	8
Wallerawang C	NSW	1000	10.88	7.3	52000	1.32	87.4	8.7	6	8
Barcaldine	QLD	55	9	3	25000	2.40	51.3	5.4	2.5	4
Barron Gorge	QLD	60	-	1	52000	7.15	0.0	0.0	0	4
Braemar	QLD	504	12	2.5	13000	7.93	51.3	5.4	1.5	0
Braemar 2	QLD	504	12	2.5	13000	7.93	51.3	5.4	1.5	0
Callide B	QLD	700	9.97	7	49500	1.19	95.0	2.0	7	4
Callide Power Plant	QLD	810	9.47	4.8	49500	1.19	95.0	2.0	9	5
Collinsville	QLD	190	13	8	65000	1.32	89.4	2.0	7	2
Condamine	QLD	140	7.5	3	31000	1.05	51.3	2.0	1.5	4
Darling Downs	QLD	630	7.83	6	31000	1.05	51.3	2.0	3	4
Gladstone	QLD	1680	10.23	5	52000	1.19	92.1	2.0	7	4
Kareeya	QLD	81	-	1	52000	7.15	0.0	0.0	0	4

Station Name	State	Capacity (MW)	Heat Rate (GJ/MWh)	Auxiliaries (%)	FOM Cost (AU$/MW/year)	VOM Cost (AU$/MWh)	Combustion Emission Factor	Fugitive Emission Factor	FOR (%)	MOR (%)
Kogan Creek	QLD	750	9.6	8	48000	1.25	94.0	2.0	7	4
Mackay	QLD	34	12.86	3	13000	9.05	69.7	5.3	1.5	0
Millmerran	QLD	850	9.6	4.5	48000	1.19	92.0	2.0	8	8
Mt Stuart	QLD	418	12	3	13000	9.05	69.7	5.3	2.5	2
Oakey	QLD	282	11.04	3	13000	9.61	51.3	5.4	2	0
Roma	QLD	80	12	3	13000	9.61	51.3	5.4	3	0
Stanwell	QLD	1440	9.89	7	49000	1.19	90.4	2.0	5.5	4
Swanbank B	QLD	480	11.8	8	55000	1.19	90.4	2.0	10	4
Swanbank E	QLD	385	7.66	3	31000	1.05	51.3	5.4	3	2
Tarong	QLD	1400	9.94	8	49500	1.43	92.1	2.0	6	4
Tarong North	QLD	443	9.18	5	48000	1.43	92.1	2.0	6	4
Townsville	QLD	240	7.83	3	31000	1.05	51.3	5.4	3	2
Wivenhoe	QLD	500	-	1	52000	7.15	0.0	0.0	0	4
Yarwun Cogen	QLD	168	10.59	2	25000	0.00	51.3	5.4	3	0
Anglesea	VIC	160	13.24	10	81000	1.19	91.0	0.3	6	2
Bairnsdale	VIC	92	10.59	3	13000	2.26	51.3	5.8	2.5	0
Bogong	VIC	140	-	1	52000	7.15	0.0	0.0	0	4
Dartmouth	VIC	158	-	1	52000	7.15	0.0	0.0	0	4
Eildon	VIC	120	-	1	52000	7.15	0.0	0.0	0	4
Energy Brix Complex	VIC	195	15	15	60000	1.19	99.0	0.3	5.5	4
Hazelwood	VIC	1640	16.36	10	84030	1.19	93.0	0.3	5.5	8
Hume (Vic)	VIC	29	-	1	52000	7.15	0.0	0.0	0	4
Jeeralang A	VIC	228	15.72	3	13000	9.05	51.3	5.8	2.5	0
Jeeralang B	VIC	255	15.72	3	13000	9.05	51.3	5.8	2.5	0
Laverton North	VIC	312	11.84	2.5	13000	7.93	51.3	5.8	1.5	2
Loy Yang A	VIC	2180	13.24	9	79000	1.19	91.5	0.3	6	2
Loy Yang B	VIC	1050	13.53	7.5	51200	1.19	91.5	0.3	7	2
Mortlake	VIC	275	11.25	3	13000	8.50	51.3	5.8	1.5	4
McKay Creek	VIC	160	-	1	52000	7.15	0.0	0.0	0	4
Murray 1	VIC	950	-	1	52000	6.15	0.0	0.0	0	4
Murray 2	VIC	550	-	1	52000	6.15	0.0	0.0	0	4
Newport	VIC	500	10.81	5	40000	2.25	51.3	5.8	2	4
Somerton	VIC	160	15	2.5	13000	9.61	51.3	5.8	1.5	0

Station Name	State	Capacity (MW)	Heat Rate (GJ/MWh)	Auxiliaries (%)	FOM Cost (AU$/MW/year)	VOM Cost (AU$/MWh)	Combustion Emission Factor	Fugitive Emission Factor	FOR (%)	MOR (%)
Valley Power	VIC	300	15	3	13000	9.61	51.3	5.8	1.5	0
West Kiewa	VIC	62	-	1	52000	7.15	0.0	0.0	0	4
Yallourn	VIC	1480	15.32	8.9	82400	1.19	92.5	0.3	7	4
Angaston	SA	50	13.85	2.5	13000	9.61	67.9	5.3	1.5	0
Clements Gap Wind Farm	SA	57	-	0	20500	1.75	0.0	0.0	NA	NA
Dry Creek	SA	156	13.85	3	13000	9.61	51.3	18.6	3	0
Hallett	SA	180	15	2.5	13000	9.61	51.3	18.6	1.5	0
Hallett 1 Wind Farm	SA	95	-	0	20500	1.75	0.0	0.0	NA	NA
Hallett 2 Wind Farm	SA	71	-	0	20500	1.75	0.0	0.0	NA	NA
Hallett 4 Wind Farm	SA	132.3	-	0	20500	1.75	0.0	0.0	NA	NA
Ladbroke Grove	SA	80	12	3	13000	3.60	51.3	18.6	3	4
Lake Bonney 2 Wind Farm	SA	159	-	0	20500	1.75	0.0	0.0	NA	NA
Lake Bonney 3 Wind Farm	SA	39	-	0	20500	1.75	0.0	0.0	NA	NA
Mintaro	SA	90	12.86	3	13000	9.61	51.3	18.6	1.5	0
Northern	SA	530	10.32	5	55000	1.19	91.0	0.9	8	8
Osborne	SA	180	8.57	5	25000	5.09	51.3	18.6	3	2
Pelican Point	SA	485	7.5	2	31000	1.05	51.3	18.6	3	4
Playford	SA	240	16.44	8	70000	3.00	91.0	0.9	13	8
Port Lincoln	SA	50	13.85	8	13000	9.61	67.9	5.3	1.5	0
Quarantine	SA	216	11.25	5	13000	9.61	51.3	18.6	2.5	0
Snowtown Wind Farm	SA	99	-	0	20500	1.75	0.0	0.0	NA	NA
Snuggery	SA	63	13.85	3	13000	9.61	67.9	5.3	2	0
Torrens Island A	SA	480	13.04	5	40000	2.25	51.3	18.6	4.5	4
Torrens Island B	SA	800	12	5	40000	2.25	51.3	18.6	4.5	4
Waterloo	SA	111	-	0	20500	1.75	0.0	0.0	NA	NA
Bastyan	TAS	79.9	-	1	52000	6.15	0.0	0.0	0	4
Tamar Valley CCGT	TAS	200	7.5	3	31000	1.05	51.3	5.8	3	2
Tamar Valley OCGT	TAS	58	12.41	2.5	13000	9.61	51.3	5.8	1.5	0
Bell Bay Three	TAS	105	12.41	2.5	13000	7.93	51.3	5.8	3	0
Cethana	TAS	85	-	1	52000	6.15	0.0	0.0	0	4

Station Name	**State**	**Capacity (MW)**	**Heat Rate (GJ/MWh)**	**Auxiliaries (%)**	**FOM Cost (AU$/MW/year)**	**VOM Cost (AU$/MWh)**	**Combustion Emission Factor**	**Fugitive Emission Factor**	**FOR (%)**	**MOR (%)**
Devils Gate	TAS	60	-	1	52000	6.15	0.0	0.0	0	4
Fisher	TAS	43.2	-	1	52000	6.15	0.0	0.0	0	4
Gordon	TAS	432	-	1	52000	6.15	0.0	0.0	0	4
John Butters	TAS	144	-	1	52000	6.15	0.0	0.0	0	4
Lake Echo	TAS	32.4	-	1	52000	6.15	0.0	0.0	0	4
Lemonthyme Wilmot	TAS	81.6	-	1	52000	6.15	0.0	0.0	0	4
Liapootah Wayatinah Catagunya	TAS	170	-	1	52000	6.15	0.0	0.0	0	4
Mackintosh	TAS	79.9	-	1	52000	6.15	0.0	0.0	0	4
Meadowbank	TAS	40	-	1	52000	6.15	0.0	0.0	0	4
Poatina	TAS	300	-	1	52000	6.15	0.0	0.0	0	4
Reece	TAS	231.2	-	1	52000	6.15	0.0	0.0	0	4
Tarraleah	TAS	90	-	1	52000	6.15	0.0	0.0	0	4
Trevallyn	TAS	80	-	1	52000	6.15	0.0	0.0	0	4
Tribute	TAS	82.8	-	1	52000	6.15	0.0	0.0	0	4
Tungatinah	TAS	125	-	1	52000	6.15	0.0	0.0	0	4

Appendix B

NEW GENERATOR CHARACTERISTICS

This appendix contains some important technical data of new entrant generators in the NEM.

Table B.1: New Entrant Generator Characteristics

Generator type	**Heat Rate (GJ/MWh)**	**Auxiliaries (%)**	**FOM Cost (AU$/MW/year)**	**VOM Cost (AU$/MWh)**	**Combustion Emission Factor**	**Fugitive Emission Factor**
CCGT	6.92	2.9	14000	2.00	51.3	9.96
CCGT-CCS	7.2	15.4	25000	4.24	51.3	9.96
OCGT	11.61	1.0	9000	2.50	51.3	9.96
Solar Photovoltaic	-	0	38000	0	0	0
Wind-Category 1	-	0	42000	0	0	0
Wind-Category 2	-	0	39000	0	0	0
Wind-Category 3	-	0	37000	0	0	0
Geothermal-Enhanced Geothermal System (EGS)	-	15	187500	0	0	0
Geothermal-Hot Sedimentary Aquifers (HSA)	-	15	125000	0	0	0
Biomass	-	0	40000	2.25	0	0

Appendix C

ANNUAL FUEL PRICES

This appendix contains annual fuel prices (in AU$/GJ) of existing and new thermal generators in the NEM.

Table C.1: Annual Fuel Prices in FC MDS

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Black Coal	Bayswater Coal	1.24	1.23	1.31	1.31	1.30	1.29	1.29	1.29	1.28	1.28	1.27	1.29	1.31	1.31	1.30	1.29	1.38	1.37	1.35	1.33	1.35
Black Coal	Callide Coal	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Black Coal	Callide B Coal	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Black Coal	Callide C Coal	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Black Coal	Collinsville Coal	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13
Black Coal	Eraring Coal	1.69	1.69	1.68	1.67	1.70	1.68	1.67	1.66	1.65	1.63	1.61	1.59	1.57	1.55	1.53	1.51	1.49	1.48	1.46	1.44	1.44
Black Coal	Gladstone Coal	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.65	1.64	1.62	1.60	1.59	1.59
Black Coal	Kogan Creek Coal	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Black Coal	Liddell Coal	1.24	1.23	1.31	1.31	1.30	1.29	1.29	1.29	1.28	1.28	1.27	1.29	1.31	1.31	1.30	1.29	1.38	1.37	1.35	1.33	1.33
Black Coal	Millmerran Coal	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Black Coal	Mt Piper Coal	1.76	1.75	1.74	1.66	1.34	1.32	1.30	1.28	1.27	1.25	1.23	1.22	1.20	1.18	1.17	1.15	1.14	1.12	1.11	1.09	1.09
Black Coal	Munmorah Coal	1.70	1.70	1.68	1.67	1.66	1.65	1.64	1.63	1.62	1.61	1.61	1.59	1.57	1.55	1.53	1.51	1.49	1.48	1.46	1.44	1.44
Black Coal	Redbank Coal	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
Black Coal	Stanwell Coal	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41
Black Coal	Swanbank Coal	1.92	1.90	1.88	1.87	1.85	1.83	1.81	1.79	1.77	1.76	1.74	1.72	1.70	1.69	1.67	1.65	1.64	1.62	1.60	1.59	1.59
Black Coal	Tarong Coal	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Black Coal	Tarong North Coal	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02

Table C.1: Annual Fuel Prices in FC MDS Contd.

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Black Coal	Vales Point Coal	1.70	1.70	1.68	1.67	1.66	1.65	1.64	1.63	1.62	1.61	1.61	1.59	1.57	1.55	1.53	1.51	1.49	1.48	1.46	1.44	1.44
Black Coal	Wallerwang Coal	1.76	1.75	1.74	1.66	1.34	1.32	1.30	1.28	1.27	1.25	1.23	1.22	1.20	1.18	1.17	1.15	1.14	1.12	1.11	1.09	1.09
Brown Coal	Anglesea Coal	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Brown Coal	Leigh Creek Coal	1.52	1.52	1.52	1.52	1.52	1.52	1.52	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Brown Coal	Loy Yang Coal	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
Brown Coal	Morwell Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Brown Coal	Yallourn Coal	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Gas	Bairnsdale Gas	4.47	4.48	4.49	4.50	4.53	4.56	4.92	5.44	5.85	6.29	6.55	6.67	6.75	6.85	7.00	7.10	7.41	7.71	8.01	8.17	8.28
Gas	Coal Seam Gas	1.51	1.48	1.48	1.50	1.68	2.15	2.59	2.84	3.00	3.05	3.13	3.23	3.30	3.34	3.36	3.48	3.88	4.29	4.69	4.76	4.82
Gas	Katnook Boral Gas	4.23	4.29	4.37	4.56	4.79	4.93	5.04	5.34	5.75	6.01	6.19	6.51	6.83	7.05	7.31	7.50	7.60	7.69	7.78	7.91	8.00
Gas	Latrobe Valley Gas	3.82	3.83	3.84	3.85	3.88	3.91	4.27	4.79	5.20	5.64	5.90	6.02	6.10	6.20	6.35	6.45	6.76	7.06	7.36	7.52	7.63
Gas	Melbourne Gas	3.92	3.93	3.94	3.95	3.98	4.01	4.37	4.89	5.30	5.74	6.00	6.12	6.20	6.30	6.45	6.55	6.86	7.16	7.46	7.62	7.73
Gas	NSW Gas	4.47	4.48	4.50	4.52	4.55	4.66	5.05	5.40	5.59	5.90	6.11	6.17	6.23	6.32	6.43	6.59	7.06	7.53	8.00	8.15	8.25
Gas	Osbourne Gas	4.23	4.29	4.37	4.56	4.79	4.93	5.04	5.34	5.75	6.01	6.19	6.51	6.83	7.05	7.31	7.50	7.60	7.69	7.78	7.91	8.00
Gas	Portland Gas	5.58	5.62	5.65	5.68	5.82	6.11	6.48	7.12	7.14	8.04	8.06	8.40	8.41	8.43	8.45	8.48	9.07	9.09	9.55	9.74	9.74
Gas	Pelican Point Gas	3.98	4.04	4.12	4.31	4.54	4.68	4.79	5.09	5.50	5.76	5.94	6.26	6.58	6.80	7.06	7.25	7.35	7.44	7.53	7.66	7.75
Gas	SA Peak Gas	8.94	9.07	9.23	9.63	10.10	10.40	10.64	11.27	12.14	12.69	13.07	13.75	14.43	14.88	15.43	15.84	16.04	16.23	16.43	16.69	16.89

Table C.1: Annual Fuel Prices in FC MDS Contd.

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Gas	SE QLD Gas	3.50	3.80	3.99	4.16	4.36	4.60	4.83	4.94	4.95	5.09	5.31	5.51	5.66	5.84	6.06	6.20	6.37	6.54	6.71	6.80	6.86
Gas	SE QLD Peak Gas	7.38	8.03	8.42	8.79	9.20	9.71	10.19	10.43	10.45	10.74	11.22	11.63	11.94	12.33	12.79	13.09	13.45	13.81	14.16	14.36	14.49
Gas	TAS Gas	4.55	4.58	4.59	4.59	4.59	4.59	4.59	5.25	6.22	6.78	7.14	7.27	7.29	7.30	7.33	7.35	7.53	7.71	7.88	8.03	8.14
Gas	TIPS Gas	5.21	5.34	5.49	5.79	6.03	6.05	6.10	6.47	7.06	7.54	7.71	7.62	7.56	7.70	7.90	8.07	8.14	8.28	8.43	8.58	8.72
Gas	Yabulu Gas	4.05	4.05	4.05	4.05	4.05	4.05	4.05	4.05	5.39	5.87	6.00	6.09	6.15	6.49	6.87	7.05	7.14	7.24	7.34	7.42	7.48
Gas	New VIC Gas	6.01	6.53	7.07	7.53	8.00	8.45	8.56	8.79	9.26	9.82	10.34	10.52	10.78	10.98	11.19	11.40	11.51	11.67	11.83	11.99	12.16
Gas	New VIC Peak Gas	7.51	8.17	8.83	9.41	10.00	10.56	10.7	10.98	11.57	12.27	12.92	13.15	13.48	13.73	13.99	14.25	14.39	14.59	14.79	14.99	15.19
Gas	New QLD Gas	6.37	6.88	7.32	7.72	8.11	8.15	8.31	8.81	9.29	9.74	9.84	10.01	10.12	10.22	10.33	10.44	10.54	10.65	10.76	10.86	10.86
Gas	New QLD Peak Gas	7.54	8.17	8.82	9.38	9.90	10.40	10.47	10.55	11.04	11.64	12.18	12.29	12.49	12.61	12.72	12.84	12.95	13.13	13.31	13.51	13.70
Gas	New NSW Gas	6.44	6.94	7.45	7.89	8.29	8.68	8.72	8.88	9.38	9.86	10.31	10.41	10.58	10.69	10.79	10.9	11.01	11.11	11.22	11.33	11.43
Gas	New NSW Peak Gas	8.05	8.67	9.31	9.86	10.37	10.85	10.91	11.10	11.72	12.33	12.88	13.01	13.22	13.36	13.49	13.62	13.76	13.89	14.02	14.16	14.29
Gas	New SA Gas	5.72	6.22	6.73	7.17	7.57	7.96	8.00	8.16	8.66	9.14	9.59	9.69	9.86	9.97	10.07	10.18	10.29	10.39	10.50	10.61	10.71
Gas	New SA Peak Gas	7.15	7.77	8.41	8.96	9.47	9.95	10.01	10.2	10.82	11.43	11.98	12.11	12.32	12.46	12.59	12.72	12.86	12.99	13.12	13.26	13.39
Gas	New TAS Gas	6.64	7.16	7.70	8.16	8.63	9.08	9.19	9.42	9.89	10.45	10.97	11.15	11.41	11.61	11.82	12.03	12.14	12.30	12.46	12.62	12.79
Gas	New TAS Peak Gas	8.30	8.95	9.62	10.20	10.78	11.35	11.49	11.77	12.36	13.06	13.71	13.94	14.26	14.51	14.77	15.04	15.18	15.38	15.58	15.78	15.98

Table C.1: Annual Fuel Prices in FC MDS Contd.

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Distillate	Distillate (NSW, QLD and SA Peaking)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Distillate	Jeeralang Distillate	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Distillate	Newport Distillate	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Oil	Tas Oil	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42

Table C.2: Annual Fuel Prices in MC MDS

Fuel Type	Fuel Profile	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Black Coal	Bayswater Coal	1.24	1.22	1.31	1.32	1.31	1.31	1.31	1.31	1.30	1.30	1.30	1.34	1.40	1.40	1.40	1.39	1.72	1.72	1.72	1.72	1.72
Black Coal	Callide Coal	1.33	1.33	1.32	1.32	1.32	1.31	1.31	1.31	1.30	1.30	1.30	1.30	1.29	1.29	1.29	1.28	1.28	1.28	1.27	1.27	1.27
Black Coal	Callide B Coal	1.33	1.33	1.33	1.32	1.32	1.32	1.31	1.31	1.31	1.30	1.30	1.30	1.30	1.29	1.29	1.29	1.28	1.28	1.28	1.27	1.27
Black Coal	Callide C Coal	1.33	1.33	1.33	1.32	1.32	1.32	1.31	1.31	1.31	1.30	1.30	1.30	1.30	1.29	1.29	1.29	1.28	1.28	1.28	1.27	1.27
Black Coal	Collinsville Coal	2.12	2.11	2.11	2.10	2.10	2.09	2.09	2.08	2.08	2.07	2.07	2.06	2.06	2.05	2.05	2.04	2.04	2.03	2.03	2.02	2.02
Black Coal	Eraring Coal	1.70	1.70	1.70	1.70	1.77	1.77	1.77	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83
Black Coal	Gladstone Coal	1.58	1.57	1.57	1.57	1.56	1.56	1.56	1.55	1.55	1.54	1.54	1.54	1.53	1.53	1.53	2.17	2.17	2.17	2.17	2.17	2.17
Black Coal	Kogan Creek Coal	0.76	0.75	0.75	0.75	0.75	0.75	0.75	0.74	0.74	0.74	0.74	0.74	0.73	0.73	0.73	0.73	0.73	0.73	0.72	0.72	0.72
Black Coal	Liddell Coal	1.24	1.22	1.31	1.32	1.31	1.31	1.31	1.31	1.30	1.30	1.30	1.34	1.40	1.40	1.40	1.39	1.72	1.72	1.72	1.72	1.72
Black Coal	Millmerran Coal	0.86	0.86	0.85	0.85	0.85	0.85	0.84	0.84	0.84	0.84	0.84	0.83	0.83	0.83	0.83	0.83	0.82	0.82	0.82	0.82	0.82
Black Coal	Mt Piper Coal	1.78	1.77	1.76	1.70	1.46	1.46	1.46	1.46	1.46	1.46	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47
Black Coal	Munmorah Coal	1.71	1.72	1.71	1.71	1.71	1.71	1.71	1.70	1.70	1.70	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83
Black Coal	Redbank Coal	1.01	1.01	1.00	1.00	1.00	1.00	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97	0.96	0.96	0.96
Black Coal	Stanwell Coal	1.41	1.41	1.40	1.40	1.40	1.39	1.39	1.39	1.38	1.38	1.38	1.37	1.37	1.37	1.36	1.36	1.36	1.35	1.35	1.35	1.35
Black Coal	Swanbank Coal	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17	2.17
Black Coal	Tarong Coal	1.01	1.01	1.01	1.01	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97
Black Coal	Tarong North Coal	1.01	1.01	1.01	1.01	1.00	1.00	1.00	1.00	1.00	0.99	0.99	0.99	0.99	0.98	0.98	0.98	0.98	0.97	0.97	0.97	0.97

Table C.2: Annual Fuel Prices in MC MDS Contd.

Fuel Type	Fuel Profile	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Black Coal	Vales Point Coal	1.71	1.72	1.71	1.71	1.71	1.71	1.71	1.70	1.70	1.70	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83
Black Coal	Wallerwang Coal	1.78	1.77	1.76	1.70	1.46	1.46	1.46	1.46	1.46	1.46	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47
Brown Coal	Anglesea Coal	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Brown Coal	Leigh Creek Coal	1.52	1.52	1.52	1.52	1.52	1.52	1.52	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Brown Coal	Loy Yang Coal	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
Brown Coal	Morwell Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Brown Coal	Yallourn Coal	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Gas	Bairnsdale Gas	4.47	4.48	4.49	4.50	4.53	4.56	4.92	5.44	5.85	6.29	6.55	6.67	6.75	6.85	7.00	7.10	7.41	7.71	8.01	8.17	8.28
Gas	Coal Seam Gas (QLD)	1.51	1.48	1.48	1.50	1.68	2.15	2.59	2.84	3.00	3.05	3.13	3.23	3.30	3.34	3.36	3.48	3.88	4.29	4.69	4.76	4.82
Gas	Katnook Boral Gas	4.23	4.29	4.37	4.56	4.79	4.93	5.04	5.34	5.75	6.01	6.19	6.51	6.83	7.05	7.31	7.50	7.60	7.69	7.78	7.91	8.00
Gas	Latrobe Valley Gas	3.82	3.83	3.84	3.85	3.88	3.91	4.27	4.79	5.20	5.64	5.90	6.02	6.10	6.20	6.35	6.45	6.76	7.06	7.36	7.52	7.63
Gas	Melbourne Gas	3.92	3.93	3.94	3.95	3.98	4.01	4.37	4.89	5.30	5.74	6.00	6.12	6.20	6.30	6.45	6.55	6.86	7.16	7.46	7.62	7.73
Gas	NSW Gas	4.47	4.48	4.50	4.52	4.55	4.66	5.05	5.40	5.59	5.90	6.11	6.17	6.23	6.32	6.43	6.59	7.06	7.53	8.00	8.15	8.25
Gas	Osbourne Gas	4.23	4.29	4.37	4.56	4.79	4.93	5.04	5.34	5.75	6.01	6.19	6.51	6.83	7.05	7.31	7.50	7.60	7.69	7.78	7.91	8.00
Gas	Portland Gas	5.58	5.62	5.65	5.68	5.82	6.11	6.48	7.12	7.14	8.04	8.06	8.40	8.41	8.43	8.45	8.48	9.07	9.09	9.55	9.74	9.74
Gas	Pelican Point Gas	3.98	4.04	4.12	4.31	4.54	4.68	4.79	5.09	5.50	5.76	5.94	6.26	6.58	6.80	7.06	7.25	7.35	7.44	7.53	7.66	7.75
Gas	SA Peak Gas	8.94	9.07	9.23	9.63	10.10	10.40	10.64	11.27	12.14	12.69	13.07	13.75	14.43	14.88	15.43	15.84	16.04	16.23	16.43	16.69	16.89

Table C.2: Annual Fuel Prices in MC MDS Contd.

Fuel Type	Fuel Profile	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Gas	SE QLD Gas	3.50	3.80	3.99	4.16	4.36	4.60	4.83	4.94	4.95	5.09	5.31	5.51	5.66	5.84	6.06	6.20	6.37	6.54	6.71	6.80	6.86
Gas	SE QLD Peak Gas	7.38	8.03	8.42	8.79	9.20	9.71	10.19	10.43	10.45	10.74	11.22	11.63	11.94	12.33	12.79	13.09	13.45	13.81	14.16	14.36	14.49
Gas	TAS Gas	4.55	4.58	4.59	4.59	4.59	4.59	4.59	5.25	6.22	6.78	7.14	7.27	7.29	7.30	7.33	7.35	7.53	7.71	7.88	8.03	8.14
Gas	TIPS Gas	5.21	5.34	5.49	5.79	6.03	6.05	6.10	6.47	7.06	7.54	7.71	7.62	7.56	7.70	7.90	8.07	8.14	8.28	8.43	8.58	8.72
Gas	Yabulu Gas	4.05	4.05	4.05	4.05	4.05	4.05	4.05	4.05	5.39	5.87	6.00	6.09	6.15	6.49	6.87	7.05	7.14	7.24	7.34	7.42	7.48
Gas	New VIC Gas	5.99	6.20	6.43	6.65	6.90	7.15	7.32	7.52	7.66	7.82	8.37	8.62	8.97	9.16	9.37	9.58	9.80	9.91	10.02	10.12	10.28
Gas	New VIC Peak Gas	7.49	7.75	8.04	8.31	8.63	8.94	9.15	9.41	9.58	9.77	10.46	10.78	11.21	11.45	11.71	11.97	12.25	12.39	12.52	12.66	12.85
Gas	New QLD Gas	5.84	6.03	6.24	6.43	6.62	6.81	6.91	7.04	7.20	7.28	7.75	7.92	8.18	8.28	8.38	8.48	8.58	8.69	8.79	8.89	8.99
Gas	New QLD Peak Gas	7.46	7.69	7.95	8.20	8.44	8.68	8.81	8.85	8.91	8.98	9.54	9.73	10.02	10.11	10.19	10.27	10.35	10.42	10.49	10.55	10.67
Gas	New NSW Gas	6.41	6.60	6.81	7.00	7.19	7.38	7.48	7.61	7.77	7.85	8.32	8.49	8.75	8.85	8.95	9.05	9.15	9.26	9.36	9.46	9.56
Gas	New NSW Peak Gas	8.02	8.25	8.51	8.75	8.99	9.22	9.35	9.51	9.71	9.81	10.40	10.62	10.93	11.06	11.19	11.31	11.44	11.57	11.70	11.82	11.95
Gas	New SA Gas	5.69	5.88	6.09	6.28	6.47	6.66	6.76	6.89	7.05	7.13	7.60	7.77	8.03	8.13	8.23	8.33	8.43	8.54	8.64	8.74	8.84
Gas	New SA Peak Gas	7.12	7.35	7.61	7.85	8.09	8.32	8.45	8.61	8.81	8.91	9.50	9.72	10.03	10.16	10.29	10.41	10.54	10.67	10.80	10.92	11.05
Gas	New TAS Gas	6.62	6.83	7.06	7.28	7.53	7.78	7.95	8.15	8.29	8.45	9.00	9.25	9.60	9.79	10.00	10.21	10.43	10.54	10.65	10.75	10.91
Gas	New TAS Peak Gas	8.28	8.53	8.82	9.10	9.42	9.73	9.94	10.19	10.36	10.56	11.24	11.56	11.99	12.24	12.50	12.76	13.03	13.18	13.31	13.44	13.64

Table C.2: Annual Fuel Prices in MC MDS Contd.

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Distillate	Distillate (NSW, QLD and SA Peaking)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Distillate	Jeeralang Distillate	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Distillate	Newport Distillate	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Oil	Tas Oil	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42

Table C.3: Annual Fuel Prices in SC MDS

Fuel Type	Fuel Profile	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Black Coal	Bayswater Coal	1.30	1.26	1.54	1.55	1.54	1.53	1.55	1.53	1.52	1.53	1.52	1.62	1.77	1.76	1.75	1.74	2.49	2.47	2.46	2.45	2.45
Black Coal	Callide Coal	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Black Coal	Callide B Coal	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Black Coal	Callide C Coal	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Black Coal	Collinsville Coal	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13
Black Coal	Eraring Coal	2.17	2.19	2.19	2.18	2.54	2.53	2.52	2.77	2.76	2.74	2.73	2.71	2.70	2.68	2.67	2.66	2.64	2.63	2.61	2.60	2.60
Black Coal	Gladstone Coal	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	2.53	2.51	2.50	2.49	2.48	2.48
Black Coal	Kogan Creek Coal	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Black Coal	Liddell Coal	1.30	1.26	1.54	1.55	1.54	1.53	1.55	1.53	1.52	1.53	1.52	1.62	1.77	1.76	1.75	1.74	2.49	2.47	2.46	2.45	2.45
Black Coal	Millmerran Coal	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Black Coal	Mt Piper Coal	2.11	2.11	2.11	2.15	2.32	2.30	2.29	2.28	2.26	2.25	2.24	2.23	2.21	2.20	2.19	2.18	2.16	2.15	2.14	2.13	2.13
Black Coal	Munmorah Coal	2.27	2.28	2.26	2.24	2.24	2.24	2.23	2.22	2.21	2.2	2.73	2.71	2.70	2.68	2.67	2.66	2.64	2.63	2.61	2.60	2.60
Black Coal	Redbank Coal	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01	1.01
Black Coal	Stanwell Coal	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41
Black Coal	Swanbank Coal	2.72	2.71	2.70	2.68	2.67	2.66	2.64	2.63	2.62	2.60	2.59	2.58	2.57	2.55	2.54	2.53	2.51	2.50	2.49	2.48	2.48
Black Coal	Tarong Coal	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Black Coal	Tarong North Coal	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02

Table C.3: Annual Fuel Prices in SC MDS Contd.

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Black Coal	Vales Point Coal	2.27	2.28	2.26	2.24	2.24	2.24	2.23	2.22	2.21	2.20	2.73	2.71	2.70	2.68	2.67	2.66	2.64	2.63	2.61	2.60	2.60
Black Coal	Wallerwang Coal	2.11	2.11	2.11	2.15	2.32	2.30	2.29	2.28	2.26	2.25	2.24	2.23	2.21	2.20	2.19	2.18	2.16	2.15	2.14	2.13	2.13
Brown Coal	Anglesea Coal	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39
Brown Coal	Leigh Creek Coal	1.52	1.52	1.52	1.52	1.52	1.52	1.52	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Brown Coal	Loy Yang Coal	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
Brown Coal	Morwell Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Brown Coal	Yallourn Coal	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Gas	Bairnsdale Gas	4.47	4.48	4.49	4.50	4.53	4.56	4.92	5.44	5.85	6.29	6.55	6.67	6.75	6.85	7.00	7.10	7.41	7.71	8.01	8.17	8.28
Gas	Coal Seam Gas (QLD)	1.51	1.48	1.48	1.50	1.68	2.15	2.59	2.84	3.00	3.05	3.13	3.23	3.30	3.34	3.36	3.48	3.88	4.29	4.69	4.76	4.82
Gas	Katnook Boral Gas	4.23	4.29	4.37	4.56	4.79	4.93	5.04	5.34	5.75	6.01	6.19	6.51	6.83	7.05	7.31	7.50	7.60	7.69	7.78	7.91	8.00
Gas	Latrobe Valley Gas	3.82	3.83	3.84	3.85	3.88	3.91	4.27	4.79	5.20	5.64	5.90	6.02	6.10	6.20	6.35	6.45	6.76	7.06	7.36	7.52	7.63
Gas	Melbourne Gas	3.92	3.93	3.94	3.95	3.98	4.01	4.37	4.89	5.30	5.74	6.00	6.12	6.20	6.30	6.45	6.55	6.86	7.16	7.46	7.62	7.73
Gas	NSW Gas	4.47	4.48	4.50	4.52	4.55	4.66	5.05	5.40	5.59	5.90	6.11	6.17	6.23	6.32	6.43	6.59	7.06	7.53	8.00	8.15	8.25
Gas	Osbourne Gas	4.23	4.29	4.37	4.56	4.79	4.93	5.04	5.34	5.75	6.01	6.19	6.51	6.83	7.05	7.31	7.50	7.60	7.69	7.78	7.91	8.00
Gas	Portland Gas	5.58	5.62	5.65	5.68	5.82	6.11	6.25	6.50	6.79	6.80	7.09	7.38	7.98	8.10	8.11	8.13	8.15	8.18	8.39	8.53	8.53
Gas	Pelican Point Gas	3.98	4.04	4.12	4.31	4.54	4.68	4.79	5.09	5.50	5.76	5.94	6.26	6.58	6.80	7.06	7.25	7.35	7.44	7.53	7.66	7.75
Gas	SA Peak Gas	8.94	9.07	9.23	9.63	10.10	10.40	10.64	11.27	12.14	12.69	13.07	13.75	14.43	14.88	15.43	15.84	16.04	16.23	16.43	16.69	16.89

Table C.3: Annual Fuel Prices in SC MDS Contd.

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Gas	SE QLD Gas	3.50	3.80	3.99	4.16	4.36	4.60	4.83	4.94	4.95	5.09	5.31	5.51	5.66	5.84	6.06	6.20	6.37	6.54	6.71	6.80	6.86
Gas	SE QLD Peak Gas	7.38	8.03	8.42	8.79	9.20	9.71	10.19	10.43	10.45	10.74	11.22	11.63	11.94	12.33	12.79	13.09	13.45	13.81	14.16	14.36	14.49
Gas	TAS Gas	4.55	4.58	4.59	4.59	4.59	4.59	4.59	5.25	6.22	6.78	7.14	7.27	7.29	7.30	7.33	7.35	7.53	7.71	7.88	8.03	8.14
Gas	TIPS Gas	5.21	5.34	5.49	5.79	6.03	6.05	6.10	6.47	7.06	7.54	7.71	7.62	7.56	7.70	7.90	8.07	8.14	8.28	8.43	8.58	8.72
Gas	Yabulu Gas	4.05	4.05	4.05	4.05	4.05	4.05	4.05	4.05	5.39	5.87	6.00	6.09	6.15	6.49	6.87	7.05	7.14	7.24	7.34	7.42	7.48
Gas	New VIC Gas	5.94	6.20	6.49	6.77	7.08	7.40	7.58	7.81	8.06	8.24	8.41	8.59	8.77	8.95	9.14	9.33	9.54	9.75	9.84	9.94	10.04
Gas	New VIC Peak Gas	7.42	7.74	8.12	8.46	8.85	9.25	9.48	9.77	10.08	10.30	10.52	10.74	10.96	11.19	11.42	11.67	11.92	12.18	12.30	12.42	12.55
Gas	New QLD Gas	5.77	6.00	6.27	6.52	6.77	7.02	7.13	7.28	7.47	7.56	7.64	7.72	7.78	7.85	7.91	7.97	8.03	8.07	8.11	8.15	8.19
Gas	New QLD Peak Gas	7.46	7.76	8.12	8.44	8.77	9.11	9.27	9.35	9.46	9.57	9.67	9.77	9.85	9.93	10.01	10.09	10.16	10.22	10.27	10.31	10.36
Gas	New NSW Gas	6.34	6.57	6.84	7.09	7.34	7.59	7.70	7.85	8.04	8.13	8.21	8.29	8.35	8.42	8.48	8.54	8.60	8.64	8.68	8.72	8.76
Gas	New NSW Peak Gas	7.92	8.22	8.55	8.86	9.17	9.49	9.63	9.82	10.05	10.16	10.26	10.36	10.44	10.52	10.60	10.67	10.74	10.81	10.86	10.90	10.95
Gas	New SA Gas	5.62	5.85	6.12	6.37	6.62	6.87	6.98	7.13	7.32	7.41	7.49	7.57	7.63	7.70	7.76	7.82	7.88	7.92	7.96	8.00	8.04
Gas	New SA Peak Gas	7.02	7.32	7.65	7.96	8.27	8.59	8.73	8.92	9.15	9.26	9.36	9.46	9.54	9.62	9.70	9.77	9.84	9.91	9.96	10.00	10.05
Gas	New TAS Gas	6.57	6.83	7.12	7.40	7.71	8.03	8.21	8.44	8.69	8.87	9.04	9.22	9.40	9.58	9.77	9.96	10.17	10.38	10.47	10.57	10.67
Gas	New TAS Peak Gas	8.21	8.53	8.90	9.25	9.64	10.04	10.27	10.56	10.87	11.08	11.31	11.53	11.75	11.98	12.21	12.46	12.71	12.97	13.09	13.21	13.33

Table C.3: Annual Fuel Prices in SC MDS Contd.

Fuel Type	**Fuel Profile**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Distillate	Distillate (NSW, QLD and SA Peaking)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Distillate	Jeeralang Distillate	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Distillate	Newport Distillate	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
Oil	Tas Oil	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42	10.42

Appendix D

ANNUAL BUILD COSTS

This appendix contains annual build (capital) costs (in AU\$/kW) of new entrant generators in the NEM.

Table D.1: Annual Build Costs in FC MDS

Generator Type	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CCGT	1505	1505	1505	1505	1505	1490	1476	1461	1447	1432	1418	1403	1388	1374	1359	1345	1330	1316	1301	1287
CCGT - CCS	2595	2595	2595	2595	2595	2529	2462	2396	2330	2264	2197	2131	2065	1999	1933	1866	1800	1734	1668	1601
OCGT	1084	1084	1084	1084	1084	1075	1067	1059	1050	1042	1034	1026	1017	1009	1001	993	984	976	968	960
Solar Photovoltaic	5115	5115	5115	5115	5115	5013	4910	4808	4706	4604	4501	4399	4297	4194	4092	3990	3887	3785	3683	3581
Wind -Category 1	3496	3496	3496	3496	3496	3449	3403	3356	3310	3263	3216	3170	3123	3077	3030	2984	2937	2890	2844	2797
Wind - Category 2	3175	3175	3175	3175	3175	3132	3090	3047	3005	2963	2920	2878	2836	2793	2751	2708	2666	2624	2581	2539
Wind - Category 3	3018	3018	3018	3018	3018	2978	2938	2898	2857	2817	2777	2737	2696	2656	2616	2576	2535	2495	2455	2414
Geothermal - Enhanced Geothermal System (EGS)	7586	7586	7586	7586	7586	7518	7450	7382	7315	7247	7179	7111	7044	6976	6908	6840	6772	6705	6637	6569
Geothermal - Hot Sedimentary Aquifers (HSA)	7260	7260	7260	7260	7260	7163	7065	6968	6871	6773	6676	6579	6481	6384	6287	6189	6092	5994	5897	5800
Biomass	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500	5500

Table D.2: Annual Build Costs in MC MDS

Generator Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CCGT	1368	1368	1368	1368	1368	1355	1342	1328	1315	1302	1289	1275	1262	1249	1236	1223	1209	1196	1183	1170
CCGT - CCS	2595	2595	2595	2595	2595	2562	2529	2496	2462	2429	2396	2363	2330	2297	2264	2231	2197	2164	2131	2098
OCGT	985	985	985	985	985	977	970	962	955	947	940	932	925	917	910	902	895	887	880	872
Solar Photovoltaic	4650	4650	4650	4650	4650	4557	4464	4371	4278	4185	4092	3999	3906	3813	3720	3627	3534	3441	3348	3255
Wind -Category 1	3178	3178	3178	3178	3178	3136	3093	3051	3009	2966	2924	2882	2839	2797	2755	2712	2670	2628	2585	2543
Wind - Category 2	2886	2886	2886	2886	2886	2847	2809	2770	2732	2693	2655	2616	2578	2539	2501	2462	2424	2385	2347	2308
Wind - Category 3	2744	2744	2744	2744	2744	2707	2671	2634	2598	2561	2524	2488	2451	2415	2378	2341	2305	2268	2232	2195
Geothermal - Enhanced Geothermal System (EGS)	7586	7586	7586	7586	7586	7552	7518	7484	7450	7416	7382	7348	7315	7281	7247	7213	7179	7145	7111	7077
Geothermal - Hot Sedimentary Aquifers (HSA)	7260	7260	7260	7260	7260	7211	7163	7114	7065	7017	6968	6919	6871	6822	6773	6725	6676	6627	6579	6530
Biomass	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000

Table D.3: Annual Build Costs in SC MDS

Generator Type	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CCGT	1231	1231	1231	1231	1231	1219	1207	1195	1184	1172	1160	1148	1136	1124	1112	1100	1088	1076	1065	1053
CCGT - CCS	2123	2123	2123	2123	2123	2087	2051	2015	1979	1942	1906	1870	1834	1798	1762	1726	1690	1653	1617	1581
OCGT	887	887	887	887	887	880	873	866	859	853	846	839	832	826	819	812	805	799	792	785
Solar Photovoltaic	4185	4185	4185	4185	4185	4101	4018	3934	3850	3767	3683	3599	3515	3432	3348	3264	3181	3097	3013	2930
Wind -Category 1	2860	2860	2860	2860	2860	2822	2784	2746	2708	2670	2632	2594	2555	2517	2479	2441	2403	2365	2327	2289
Wind - Category 2	2597	2597	2597	2597	2597	2563	2528	2493	2459	2424	2389	2355	2320	2285	2251	2216	2181	2147	2112	2077
Wind - Category 3	2470	2470	2470	2470	2470	2437	2404	2371	2338	2305	2272	2239	2206	2173	2140	2107	2074	2041	2008	1976
Geothermal - Enhanced Geothermal System (EGS)	6206	6206	6206	6206	6206	6169	6132	6096	6059	6022	5985	5948	5911	5874	5837	5800	5763	5726	5689	5652
Geothermal - Hot Sedimentary Aquifers (HSA)	5940	5940	5940	5940	5940	5887	5834	5781	5728	5675	5621	5568	5515	5462	5409	5356	5303	5250	5197	5144
Biomass	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500	4500

Appendix E

MAXIMUM DEMAND - NSW

This appendix contains annual maximum demands (in MW) in FC, MC and SC MDS for New South Wales. These consist of 10 % and 50% POE summer and winter MDs (as generated) in each MDS.

Table E.1: Summer 50 % POE Maximum Demand - NSW

Year/MDS	**FC**	**MC**	**SC**
2010 -11	14501	14461	14282
2011 -12	15105	15005	14642
2012 -13	15059	15043	14724
2013 -14	15555	15529	15263
2014 -15	15820	15705	15478
2015 -16	16143	15874	15526
2016 -17	16603	16201	15667
2017-18	17122	16646	15968
2018 -19	17687	17201	16383
2019 - 20	18224	17725	16777
2020 - 21	18763	18194	17108
2021 - 22	19143	18454	17244
2022 - 23	19526	18659	17329
2023 - 24	19873	18865	17378
2024 - 25	20326	19168	17540
2025 - 26	20711	19475	17731
2026 - 27	21135	19826	18001
2027 - 28	21544	20174	18216
2028 - 29	22115	20658	18486
2029 - 30	22702	21153	18761
2030 - 31	23244	21583	19030

Table E.2: Summer 10 % POE Maximum Demand - NSW

Year/MDS	**FC**	**MC**	**SC**
2010 -11	15447	15405	15214
2011 -12	16093	15987	15600
2012 -13	16054	16037	15698
2013 -14	16602	16574	16291
2014 -15	16912	16789	16546

Table E.2: Summer 10 % POE Maximum Demand - NSW Contd.

Year/MDS	FC	MC	SC
2015 -16	17262	16974	16602
2016 -17	17778	17347	16775
2017-18	18337	17826	17100
2018 -19	18943	18424	17547
2019 - 20	19532	18998	17981
2020 - 21	20124	19514	18349
2021 - 22	20531	19792	18494
2022 - 23	20941	20012	18586
2023 - 24	21314	20233	18638
2024 - 25	21790	20548	18803
2025 - 26	22215	20889	19018
2026 - 27	22662	21258	19300
2027 - 28	23103	21634	19534
2028 - 29	23719	22156	19827
2029 - 30	24352	22690	20124
2030 - 31	24943	23161	20421

Table E.3: Winter 50 % POE Maximum Demand - NSW

Year/MDS	FC	MC	SC
2011	14333	14326	14182
2012	14706	14659	14352
2013	14497	14545	14300
2014	14905	14972	14805
2015	15132	15139	15034
2016	15617	15468	15237
2017	16109	15832	15418
2018	16615	16266	15711
2019	17050	16694	16006
2020	17544	17180	16369
2021	18100	17670	16726
2022	18522	17976	16909
2023	18917	18200	17015
2024	19318	18462	17120
2025	19751	18751	17273
2026	20168	19092	17498
2027	20656	19508	17829
2028	21183	19970	18152
2029	21723	20428	18402
2030	22276	20896	18656
2031	22795	21315	18924

Table E.4: Winter 10 % POE Maximum Demand - NSW

Year/MDS	FC	MC	SC
2011	14725	14718	14569
2012	15111	15063	14747
2013	14892	14942	14690
2014	15312	15381	15210

Table E.4: Winter 10 % POE Maximum Demand - NSW Contd.

Year/MDS	FC	MC	SC
2015	15539	15546	15439
2016	16043	15890	15653
2017	16547	16263	15838
2018	17067	16709	16139
2019	17517	17152	16444
2020	18025	17650	16817
2021	18585	18143	17174
2022	19020	18459	17364
2023	19417	18681	17464
2024	19830	18951	17573
2025	20277	19251	17733
2026	20708	19603	17966
2027	21200	20021	18299
2028	21742	20497	18630
2029	22300	20971	18891
2030	22873	21456	19156
2031	23405	21885	19430

Appendix F

MAXIMUM DEMAND - QLD

This appendix contains annual maximum demands (in MW) in FC, MC and SC MDS for Queensland. These consist of 10 % and 50% POE summer and winter MDs (as generated) in each MDS.

Table F.1: Summer 50 % POE Maximum Demand - QLD

Year/MDS	FC	MC	SC
2010 -11	9588	9686	9527
2011 -12	10333	10342	10242
2012 -13	11159	11012	10853
2013 -14	12133	11676	11470
2014 -15	12942	12203	11951
2015 -16	13572	12706	12379
2016 -17	14188	13236	12795
2017-18	14737	13779	13179
2018 -19	15296	14340	13563
2019 - 20	15691	14710	13823
2020 - 21	15991	14949	13959
2021 - 22	16429	15248	14108
2022 - 23	16921	15557	14287
2023 - 24	17376	15851	14481
2024 - 25	17817	16130	14725
2025 - 26	18252	16456	15006
2026 - 27	18771	16864	15352
2027 - 28	19489	17469	15764
2028 - 29	20195	18109	16137
2029 - 30	20926	18773	16518
2030 - 31	21804	19447	17010

Table F.2: Summer 10 % POE Maximum Demand - QLD

Year/MDS	FC	MC	SC
2010 -11	10082	10185	10018
2011 -12	10865	10874	10769
2012 -13	11735	11581	11413
2013 -14	12761	12280	12063
2014 -15	13613	12835	12571
2015 -16	14275	13365	13021

Table F.2: Summer 10 % POE Maximum Demand - QLD Contd.

Year/MDS	FC	MC	SC
2016 -17	14925	13923	13459
2017-18	15503	14496	13864
2018 -19	16094	15088	14270
2019 - 20	16509	15477	14544
2020 - 21	16826	15729	14688
2021 - 22	17288	16044	14845
2022 - 23	17806	16370	15034
2023 - 24	18285	16680	15239
2024 - 25	18750	16975	15497
2025 - 26	19208	17318	15792
2026 - 27	19755	17748	16157
2027 - 28	20511	18386	16591
2028 - 29	21255	19060	16984
2029 - 30	22026	19759	17386
2030 - 31	22950	20470	17905

Table F.3: Winter 50 % POE Maximum Demand - QLD

Year/MDS	FC	MC	SC
2011	8680	8789	8665
2012	9190	9229	9171
2013	9889	9802	9703
2014	10647	10309	10189
2015	11278	10717	10577
2016	11858	11183	10973
2017	12429	11678	11369
2018	12941	12185	11734
2019	13421	12667	12060
2020	13649	12882	12186
2021	13907	13088	12303
2022	14309	13370	12453
2023	14757	13659	12628
2024	15151	13915	12797
2025	15527	14152	13005
2026	15852	14389	13208
2027	16319	14760	13527
2028	16952	15298	13897
2029	17570	15862	14228
2030	18210	16446	14567
2031	18927	17000	14972

Table F.4: Winter 10 % POE Maximum Demand - QLD

Year/MDS	FC	MC	SC
2011	8802	8913	8786
2012	9319	9359	9300
2013	10029	9941	9840
2014	10798	10455	10333
2015	11438	10869	10727

Table F.4: Winter 10 % POE Maximum Demand - QLD Contd.

Year/MDS	**FC**	**MC**	**SC**
2016	12027	11342	11129
2017	12606	11844	11531
2018	13125	12358	11901
2019	13612	12847	12232
2020	13844	13066	12360
2021	14106	13275	12479
2022	14514	13561	12631
2023	14969	13855	12809
2024	15369	14114	12980
2025	15750	14355	13192
2026	16080	14596	13398
2027	16554	14972	13721
2028	17197	15519	14097
2029	17823	16091	14433
2030	18473	16684	14778
2031	19201	17246	15189

Appendix G

MAXIMUM DEMAND - VIC

This appendix contains annual maximum demands (in MW) in FC, MC and SC MDS for Victoria. These consist of 10 % and 50% POE summer and winter MDs (as generated) in each MDS.

Table G.1: Summer 50 % POE Maximum Demand - VIC

Year/MDS	**FC**	**MC**	**SC**
2010 -11	10493	10298	10056
2011 -12	10507	10257	9899
2012 -13	10773	10450	10104
2013 -14	11079	10681	10324
2014 -15	11401	10895	10461
2015 -16	11644	11040	10523
2016 -17	11957	11246	10659
2017-18	12506	11725	11065
2018 -19	13030	12194	11446
2019 - 20	13527	12610	11807
2020 - 21	13820	12818	11978
2021 - 22	14291	13155	12206
2022 - 23	14668	13376	12268
2023 - 24	15080	13651	12351
2024 - 25	15427	13838	12411
2025 - 26	15810	14105	12588
2026 - 27	16266	14438	12854
2027 - 28	16845	14901	13152
2028 - 29	17268	15269	13301
2029 - 30	17701	15645	13452
2030 - 31	18192	15990	13649

Table G.2: Summer 10 % POE Maximum Demand - VIC

Year/MDS	**FC**	**MC**	**SC**
2010 -11	11304	11094	10833
2011 -12	11245	10978	10595
2012 -13	11610	11262	10889
2013 -14	11965	11535	11150
2014 -15	12243	11700	11234

Table G.2: Summer 10 % POE Maximum Demand - VIC Contd.

Year/MDS	FC	MC	SC
2015 -16	12509	11860	11305
2016 -17	12898	12131	11497
2017-18	13422	12584	11875
2018 -19	14103	13199	12389
2019 - 20	14586	13597	12732
2020 - 21	14866	13788	12885
2021 - 22	15379	14157	13136
2022 - 23	15853	14457	13259
2023 - 24	16419	14863	13448
2024 - 25	16825	15092	13536
2025 - 26	17202	15347	13696
2026 - 27	17668	15683	13963
2027 - 28	18229	16125	14232
2028 - 29	18722	16554	14421
2029 - 30	19227	16994	14612
2030 - 31	19787	17392	14846

Table G.3: Winter 50 % POE Maximum Demand - VIC

Year/MDS	FC	MC	SC
2011	8555	8415	8236
2012	8502	8328	8065
2013	8561	8341	8101
2014	8724	8463	8230
2015	8856	8529	8252
2016	9039	8632	8288
2017	9303	8813	8412
2018	9675	9135	8680
2019	10023	9444	8924
2020	10308	9674	9118
2021	10495	9800	9219
2022	10753	9965	9308
2023	11015	10113	9337
2024	11238	10242	9328
2025	11510	10395	9385
2026	11758	10561	9488
2027	12035	10755	9639
2028	12360	11007	9780
2029	12626	11239	9856
2030	12897	11476	9933
2031	13170	11657	10020

Table G.4: Winter 10 % POE Maximum Demand - VIC

Year/MDS	FC	MC	SC
2011	8692	8550	8368
2012	8649	8472	8204
2013	8714	8491	8246
2014	8877	8611	8374

Table G.4: Winter 10 % POE Maximum Demand - VIC Contd.

Year/MDS	FC	MC	SC
2015	9011	8678	8397
2016	9194	8781	8430
2017	9455	8957	8550
2018	9840	9291	8828
2019	10201	9611	9082
2020	10482	9837	9273
2021	10683	9975	9384
2022	10933	10132	9464
2023	11214	10296	9506
2024	11428	10415	9486
2025	11696	10563	9537
2026	11962	10744	9652
2027	12249	10946	9810
2028	12602	11223	9971
2029	12837	11427	10021
2030	13075	11635	10070
2031	13351	11818	10158

Appendix H

MAXIMUM DEMAND - SA

This appendix contains annual maximum demands (in MW) in FC, MC and SC MDS for South Australia. These consist of 10 % and 50% POE summer and winter MDs (as generated) in each MDS.

Table H.1: Summer 50 % POE Maximum Demand - SA

Year/MDS	FC	MC	SC
2010 -11	3378	3398	3266
2011 -12	3367	3392	3218
2012 -13	3375	3385	3251
2013 -14	3491	3465	3347
2014 -15	3567	3515	3400
2015 -16	3662	3596	3473
2016 -17	3805	3695	3535
2017-18	3920	3778	3560
2018 -19	4062	3913	3632
2019 - 20	4182	4025	3752
2020 - 21	4264	4089	3850
2021 - 22	4371	4155	3908
2022 - 23	4479	4219	3921
2023 - 24	4594	4298	3929
2024 - 25	4717	4378	3967
2025 - 26	4840	4464	4025
2026 - 27	4962	4557	4099
2027 - 28	5080	4661	4162
2028 - 29	5173	4757	4209
2029 - 30	5268	4856	4257
2030 - 31	5389	4945	4312

Table H.2: Summer 10 % POE Maximum Demand - SA

Year/MDS	FC	MC	SC
2010 -11	3624	3646	3503
2011 -12	3665	3692	3502
2012 -13	3644	3655	3510
2013 -14	3782	3755	3626
2014 -15	3890	3834	3708

Table H.2: Summer 10 % POE Maximum Demand - SA Contd.

Year/MDS	FC	MC	SC
2015 -16	3964	3892	3759
2016 -17	4121	4001	3828
2017-18	4294	4139	3900
2018 -19	4432	4269	3963
2019 - 20	4577	4405	4106
2020 - 21	4670	4478	4217
2021 - 22	4779	4543	4273
2022 - 23	4902	4617	4291
2023 - 24	5031	4707	4303
2024 - 25	5159	4788	4338
2025 - 26	5297	4886	4406
2026 - 27	5435	4992	4491
2027 - 28	5558	5100	4554
2028 - 29	5666	5211	4611
2029 - 30	5776	5324	4668
2030 - 31	5913	5426	4732

Table H.3: Winter 50 % POE Maximum Demand - SA

Year/MDS	FC	MC	SC
2011	2684	2706	2607
2012	2724	2753	2620
2013	2693	2712	2617
2014	2776	2772	2694
2015	2834	2815	2744
2016	2895	2863	2785
2017	2979	2913	2806
2018	3106	3015	2861
2019	3214	3117	2913
2020	3305	3202	3005
2021	3374	3256	3087
2022	3442	3295	3120
2023	3530	3347	3131
2024	3624	3413	3141
2025	3715	3471	3166
2026	3805	3533	3207
2027	3902	3608	3267
2028	3986	3682	3310
2029	4059	3758	3347
2030	4134	3836	3385
2031	4224	3904	3428

Table H.4: Winter 10 % POE Maximum Demand - SA

Year/MDS	FC	MC	SC
2011	2837	2860	2755
2012	2876	2907	2767
2013	2860	2881	2779
2014	2924	2920	2838

Table H.4: Winter 10 % POE Maximum Demand - SA Contd.

Year/MDS	**FC**	**MC**	**SC**
2015	2992	2972	2897
2016	3082	3049	2965
2017	3158	3088	2975
2018	3290	3193	3029
2019	3432	3328	3111
2020	3524	3415	3204
2021	3594	3469	3288
2022	3674	3516	3330
2023	3774	3579	3348
2024	3871	3646	3355
2025	3974	3714	3387
2026	4067	3776	3428
2027	4157	3843	3480
2028	4254	3930	3532
2029	4340	4019	3579
2030	4428	4109	3627
2031	4531	4187	3676

Appendix I

MAXIMUM DEMAND - TAS

This appendix contains annual maximum demands (in MW) in FC, MC and SC MDS for Tasmania. These consist of 10 % and 50% POE summer and winter MDs (as generated) in each MDS.

Table I.1: Summer 50 % POE Maximum Demand - TAS

Year/MDS	FC	MC	SC
2010 -11	1554	1509	1497
2011 -12	1573	1552	1488
2012 -13	1594	1556	1545
2013 -14	1616	1582	1609
2014 -15	1625	1591	1648
2015 -16	1635	1586	1662
2016 -17	1698	1595	1639
2017-18	1783	1640	1620
2018 -19	1853	1713	1634
2019 - 20	1924	1798	1751
2020 - 21	1980	1865	1869
2021 - 22	2025	1906	1927
2022 - 23	2064	1930	1914
2023 - 24	2110	1954	1876
2024 - 25	2178	1981	1856
2025 - 26	2249	2013	1866
2026 - 27	2310	2057	1915
2027 - 28	2355	2118	1991
2028 - 29	2405	2195	2083
2029 - 30	2456	2275	2179
2030 - 31	2517	2326	2221

Table I.2: Summer 10 % POE Maximum Demand - TAS

Year/MDS	FC	MC	SC
2010 -11	1580	1535	1523
2011 -12	1600	1579	1513
2012 -13	1621	1582	1571
2013 -14	1643	1609	1636
2014 -15	1654	1619	1676

Table I.2: Summer 10 % POE Maximum Demand - TAS Contd.

Year/MDS	FC	MC	SC
2015 -16	1663	1614	1691
2016 -17	1727	1623	1667
2017-18	1814	1668	1647
2018 -19	1885	1743	1662
2019 - 20	1957	1829	1781
2020 - 21	2014	1897	1902
2021 - 22	2060	1939	1961
2022 - 23	2100	1964	1948
2023 - 24	2147	1988	1909
2024 - 25	2217	2016	1889
2025 - 26	2289	2048	1899
2026 - 27	2351	2094	1949
2027 - 28	2397	2156	2026
2028 - 29	2448	2234	2120
2029 - 30	2501	2316	2218
2030 - 31	2563	2369	2262

Table I.3: Winter 50 % POE Maximum Demand - TAS

Year/MDS	FC	MC	SC
2011	2104	2048	2037
2012	2088	2068	1989
2013	2100	2059	2054
2014	2069	2037	2085
2015	2165	2136	2229
2016	2191	2141	2260
2017	2214	2094	2167
2018	2321	2149	2138
2019	2420	2252	2161
2020	2516	2367	2320
2021	2588	2455	2477
2022	2645	2507	2551
2023	2695	2537	2534
2024	2758	2571	2485
2025	2852	2612	2463
2026	2937	2647	2470
2027	3015	2703	2533
2028	3073	2782	2632
2029	3137	2882	2753
2030	3203	2986	2879
2031	3275	3048	2930

Table I.4: Winter 10 % POE Maximum Demand - TAS

Year/MDS	FC	MC	SC
2011	2130	2073	2062
2012	2114	2093	2014
2013	2126	2084	2079
2014	2095	2063	2111

Table I.4: Winter 10 % POE Maximum Demand - TAS Contd.

Year/MDS	**FC**	**MC**	**SC**
2015	2192	2162	2256
2016	2218	2167	2287
2017	2241	2120	2193
2018	2350	2176	2164
2019	2450	2280	2188
2020	2547	2396	2350
2021	2621	2486	2508
2022	2679	2538	2583
2023	2729	2570	2566
2024	2793	2604	2517
2025	2888	2645	2494
2026	2975	2681	2501
2027	3054	2738	2565
2028	3113	2818	2667
2029	3178	2920	2789
2030	3245	3025	2917
2031	3318	3088	2969

Appendix J

ANNUAL ENERGY PROJECTION

This appendix contains annual energy projections (in GWh) controlled by NEM dispatch process in FC, MC and SC MDS.

Table J.1: Annual Energy Projection

Year/MDS	FC	MC	SC
2011	205077	204420	200111
2012	209045	207654	204098
2013	215504	212413	209589
2014	221237	216107	213526
2015	227215	220225	216498
2016	234091	225145	219360
2017	241172	231377	223249
2018	248294	238483	227926
2019	255111	245066	233573
2020	261115	250098	237812
2021	266994	254030	240071
2022	273390	257763	241430
2023	279515	261591	242476
2024	286027	265499	244516
2025	292099	269827	247480
2026	299386	275522	252220
2027	307548	282547	256951
2028	315467	289837	260953
2029	323379	295903	264862
2030	323379	295903	264862

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