Collinsville solar thermal project: Energy economics and dispatch forecasting - Final report

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University of Queensland

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COLLINSVILLE SOLAR THERMAL PROJECT

ENERGY ECONOMICS AND DISPATCH FORECASTING

Final Report

The University of Queensland
Australia

Global Change Institute

Prepared for

RATCH-Australia Corporation

RATCH-Australia Corporation

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Preface

This combined Energy Economics and Dispatch Forecasting report is one of seven reports evaluating the feasibility of a hybrid gas-concentrated solar power (CSP) plant using Linear Fresnel Reflector (LFR) technology to replace the coal-fired power station at Collinsville, Queensland, Australia. Table 1 shows the seven reports and the affiliation of the lead authors.

Table 1: Collinsville feasibility study reports and their lead researcher groups and authors

Report	Affiliation of the lead author
Yield forecasting (Bell, Wild & Foster 2014b)	EEMG
*Dispatch forecasting (Bell, Wild & Foster 2014a)	EEMG
*Energy economics (Bell, Wild & Foster 2014a)	EEMG
Solar mirror cleaning requirements (Guan, Yu & Gurgenci 2014)	SMME
Optimisation of operational regime (Singh & Gurgenci 2014b)	SMME
Fossil fuel boiler integration (Singh & Gurgenci 2014a)	SMME
Power system stability assessment (Shah, Yan & Saha 2014a)	PESG
Yield analysis of a LFR based CSP by long-term historical data (Shah, Yan & Saha 2014b)	PESG

*Combined report

These reports are part of a collaborative research agreement between RATCH Australia and the University of Queensland (UQ) funded by the Australian Renewable Energy Agency (ARENA) and administered by the Global Change Institute (GCI) at UQ. Three groups from different schools undertook the research: Energy Economics and Management Group (EEMG) from the School of Economics, a group from the School of Mechanical and Mining Engineering (SMME) and the Power and Energy Systems Group (PESG) from the School of Information Technology and Electrical Engineering (ITEE).

EEMG are the lead authors for three of the reports. Table 2 shows the “Collinsville Solar Thermal - Research Matrix” that was supplied by GCI to the researchers at EEMG for their reports. We restructured the suggested content for the three reports in the matrix to provide a more logical presentation for the reader that required combining the Energy Economics and Dispatch Forecasting reports.

Table 2: Collinsville Solar Thermal - Research Matrix – EEMG's components

Yield Forecasting Modelling and analysis of the solar output in order that the financial feasibility of the plant may be determined using a long-term yield estimate together with the dispatch model and the modelled long-term spot price.
Dispatch Forecasting Analysis of the expected dispatch of the plant at various times of day and various months would lead to better prediction of the output of the plant and would improve the ability to negotiate a satisfactory PPA for the electricity produced. Run value dispatch models (using pricing forecast to get $ values out). Output will inform decision about which hours the plant should run.
Energy Economics Integration of the proposed system into the University of Queensland's Energy Economics Management Group's (EEMG) existing National Electricity Market (NEM) models to look at the interaction of the plant within the NEM to determine its effects on the power system considering the time of day and amount of power produced by the plant. Emphasis to be on future price forecasting.

This Energy economics and dispatch forecasting report uses the results from our 'Yield forecasting' report (Bell, Wild & Foster 2014b).

Justification for combining the Energy Economics and Dispatch Forecasting reports

The following paragraphs provide a detailed justification for combining the Energy Economics and Dispatch Forecasting reports. This justification can be skipped by most readers because the justification is most probably only of interest to ARENA and RATCH.

The matrix identifies improving the negotiation of a PPA as an important outcome of the project. This objective is paramount given the failure of many renewable energy projects stem from the failure to negotiate a suitable PPA. The negotiation of a PPA is required with a purchaser of the electricity before banks or other intermediaries will provide finance for the project. The financiers also require profit calculations for the lifetime of the plant before financial approval is given, so the calculations are both essential to finalise the start of a project and to aid in negotiating a PPA.

The revenue calculation requires both the prices and dispatch. However, the 'Energy Economics Report' is to present prices and the 'Dispatch Forecasting Report' is to present dispatch and PPA. Therefore, there would be duplication between the reports whichever report presents the calculations. This duplication is unnecessary in a combined report. In addition, the same EEMG 'National Electricity Market (NEM)' model produces both prices and dispatch simultaneously, so it is more logical to discuss EEMG's model and its outputs: prices and dispatch, in the same report.

Furthermore, there is the failure of logic of presentation in the three-report format. We calculated revenue from the prices and dispatch, so a logical presentation is to discuss the prices and dispatch first then introduce the revenue calculations. This is not feasible in the three-report format without duplication. Therefore, both clarity of exposition and removal of duplication arguments make amalgamation of the 'Energy Economics' and 'Dispatch Forecasting' reports sensible.

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Executive Summary

1 Introduction

This report primarily aims to provide both dispatch and wholesale spot price forecasts for the proposed hybrid gas-solar thermal plant at Collinsville, Queensland, Australia for its lifetime 2017-47. These forecasts are to facilitate Power Purchase Agreement (PPA) negotiations and to evaluate the proposed dispatch profile in Table 3. The solar thermal component of the plant uses Linear Fresnel Reflector (LFR) technology. The proposed profile maintains a 30 MW dispatch during the weekdays by topping up the yield from the LFR by dispatch from the gas generator and imitates a baseload function currently provided by coal generators. This report is the second of two reports and uses the findings of our first report on yield forecasting (Bell, Wild & Foster 2014b).

2 Literature review

The literature review discusses demand and supply forecasts, which we use to forecast wholesale spot prices with the Australian National Electricity Market (ANEM) model.

The review introduces the concept of gross demand to supplement the Australian Electricity Market Operator's (AEMO) "total demand". This gross demand concept helps to explain the permanent transformation of the demand in the National Electricity Market (NEM) region and the recent demand over forecasting by the AEMO. We also discuss factors causing the permanent transformation. The review also discusses the implications of the irregular ENSO cycle for demand and its role in over forecasting demand.

Forecasting supply requires assimilating the information in the *Electricity Statement of Opportunities* (ESO) (AEMO 2013a, 2014c). AEMO expects a reserve surplus across the NEM beyond 2023-24. Compounding this reserve surplus, there is a continuing decline in manufacturing, which is freeing up supply capacity elsewhere in the NEM. The combined effect of export LNG prices and declining total demand are hampering decisions to transform proposed gas generation investment into actual investment and hampering the role for gas as a bridging technology in the NEM. The review also estimates expected lower and upper bounds for domestic gas prices to determine the sensitivity of the NEM's wholesale spot prices and plant's revenue to gas prices.

The largest proposed investment in the NEM is from wind generation but the low demand to wind speed correlation induces wholesale spot price volatility. However, McKinsey Global Institute (MGI 2014) and Norris et al. (2014a) expect economically viable energy storage shortly beyond the planning horizon of the ESO in 2023-24. We expect that this viability will not only defer investment in generation and transmission but also accelerate the growth in off-market produced and consumed electricity within the NEM region.

2.1 Research questions

The report has the following overarching research questions:

> *What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?*

What are the wholesale spots prices on the NEM given the plant's dispatch profile?

The literature review refines the latter research question into five more specific research questions ready for the methodology:

- *What are the half-hourly wholesale spots prices for the plant's lifetime without gas as a bridging technology?*
  - *Assuming a reference gas price of between \$5.27/GJ to \$7.19/GJ for base-load gas generation (depending upon nodal location;) and*
  - *for peak-load gas generation of between \$6.59/GJ to \$8.99/GJ; and*
  - *given the plant's dispatch profile*
- *What are the half-hourly wholesale spots prices for the plant's lifetime with gas as a bridging technology?*
  - *Assuming some replacement of coal with gas generation*
- *How sensitive are wholesale spot prices to higher gas prices?*
  - *Assuming high gas prices are between \$7.79/GJ to \$9.71/GJ for base-load gas generation (depending upon nodal location); and*
  - *for peak-load gas generation of between \$9.74/GJ to \$12.14/GJ; and*
- *What is the plant's revenue for the reference gas prices?*
- *How sensitive is the plant's revenue to gas as a bridging technology?*
- *How sensitive is the plant's revenue to the higher gas prices?*
- *What is the levelised cost of energy for the proposed plant?*

3 Methodology

In the methodology section, we discuss the following items:

- dispatch forecasting for the proposed plant;
- supply capacity for the years 2014-47 for the NEM;
- demand forecasting using a Typical Meteorological Year (TMY); and
- wholesale spot prices calculation using ANEM, supply capacity and total demand
- define three scenarios to address the research questions:
  - reference gas prices;
  - gas as a bridging technology; and
  - high gas prices.

The TMY demand matches the solar thermal plant's TMY yield forecast that we developed in our previous report (Bell, Wild & Foster 2014b). Together, these forecasts help address the research questions.

4 Results

In the results section we will present the findings for each research question, including

- the TMY yield for the LFR and the dispatch of the gas generator given the proposed dispatch profile in Table 3;
- Average annual wholesale spot prices from 2017 to 2047 for the plant's node for:
  - Reference gas prices scenario from \$18/MWh to \$38/MWh
  - Gas as a bridging technology scenario from \$18/MWh to \$110/MWh

  - High gas price scenario from \$20/MWh to \$41/MWh
- The combined plants revenue without subsidy given the proposed profile:
  - Reference gas price scenario \$36 million
  - Gas as a bridging technology scenario \$52 million
  - High gas price scenario \$47 million

5 Discussion

In the discussion section, we analyse:

- reasons for the changes in the average annual spot prices for the three scenarios; and
- the frequency that the half-hourly spot price exceeds the Short Run Marginal Cost (SRMC) of the gas generator for the three scenarios for:
  - day of the week;
  - month of the year; and
  - time of the day.

If the wholesale spot price exceeds the SRMC, dispatch from the gas plant contributes towards profits. Otherwise, the dispatch contributes towards a loss. We find that for both reference and high gas price scenarios the proposed profile in Table 3 captures exceedances for the day of the week and the time of the day but causes the plant to run at a loss for several months of the year. Figure 14 shows that the proposed profile captures the exceedance by hour of the day and Figure 16 shows that only operating the gas component Monday to Friday is well justified. However, Figure 15 shows that operating the gas plant in April, May, September and October is contributing toward a loss. Months either side of these four months have a marginal number of exceedances. In the unlikely case of gas as a bridging scenario, extending the proposed profile to include the weekend and operating from 6 am to midnight would contribute to profits.

We offer an alternative strategy to the proposed profile because the proposed profile in the most likely scenarios proves loss making when considering the gas component's operation throughout the year. The gas-LFR plant imitating the based-load role of a coal generator takes advantage of the strengths of the gas and LFR component, that is, the flexibility of gas to compensate for the LFR's intermittency, and utilising the LFR's low SRMC. However, the high SRMC of the gas component in a baseload role loses the flexibility to respond to market conditions and contributes to loss instead of profit and to CO_2 production during periods of low demand.

The alternative profile retains the advantages of the proposed profile but allows the gas component freedom to exploit market conditions. Figure 17 introduces the perfect day's yield profile calculated from the maximum hourly yield from the years 2007-13. The gas generator tops up the actual LFR yield to the perfect day's yield profile to cover LFR intermittency. The residual capacity of the gas generator is free to meet demand when spot market prices exceed SRMC and price spikes during Value-of-Lost-Load (VOLL) events. The flexibility of the gas component may prove more advantageous as the penetration of intermittent renewable energy increases.

6 Conclusion

We find that the proposed plant is a useful addition to the NEM but the proposed profile is unsuitable because the gas component is loss making for four months of the year and producing CO_2 during periods of low demand. We recommend further research using the alternative perfect day's yield profile.

7 Further Research

We discuss further research compiled from recommendation elsewhere in the report.

8 Appendix A Australian National Electricity Market Model Network

This appendix provides diagrams of the generation and load serving entity nodes and the transmission lines that the ANEM model uses. There are 52 nodes and 68 transmission lines, which make the ANEM model realistic. In comparison, many other models of the NEM are highly aggregated.

9 Appendix B Australian National Electricity Market Model

This appendix describes the ANEM model in detail and provides additional information on the assumptions made about the change in the generation fleet in the NEM during the lifetime of the proposed plant.

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Tables

Equations

Abbreviations

ABS	Australian Bureau of Statistics
AC	Alternating Current
ACF	Annual Capacity Factor
AEMC	Australian Electricity Market Commission
AEMO	Australian Energy Market Operator
AGL	Australian Gas Limited
ANEM	Australian National Electricity Market Model (from EEMG)
ARENA	Australian Renewable Energy Agency
BRANZ	Building Research Advisory New Zealand
BREE	Bureau of Resources and Energy Economics
CCGT	Combined Cycle Gas Turbine
CER	Clean Energy Regulator
CSP	Concentrated Solar Power
DC OPF	Direct Current Optimal Power Flow
DNI	Direct Normal Irradiance
E3	Equipment Energy Efficiency
EEMG	Energy Economics and Management Group (at UQ)
ENSO	El Niño Southern Oscillation
ESO	Electricity Statement of Opportunities
GCI	Global Change Institute
GDP	Gross Domestic Product
GHG	Green House Gas
GJ	Gigajoule
IEA	International Energy Agency
ISO	Independent System Operator
ITEE	Information Technology and Electrical Engineering (at UQ)
LCOE	Levelised Cost of Energy

LFR	Linear Fresnel Reflector
LMP	Locational Marginal Price
LNG	Liquid Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
LSE	Load Serving Entity
MCE	Ministerial Council on Energy
MEPS	Minimum Energy Performance Standards
MGI	McKinsey Global Institute
MVA	Megavoltamperes
MW	Megawatt
MWh	Megawatt hour
NEFR	National Electricity Forecast Report
NEM	National Electricity Market
NFEE	National Framework for Energy Efficiency
NGF	National Generators Forum
NREL	US National Renewable Energy Laboratory
NSP	Network Service Provider
NSW	New South Wales
NPV	Net Present Value
OECD	Organisation for Economic Cooperation and Development
OCGT	Open Cycle Gas Turbine
PESG	Power and Energy Systems Group (at UQ)
PPA	Power Purchase Agreement
PV	Photovoltaic
QLD	Queensland
RAC	RATCH Australia Corporation
SA	South Australia

SAM	Systems Advisor Model (from NREL)
SWH	Solar Water Heater
SOI	Southern Oscillation Index
SRMC	Short Run Marginal Cost
LRMC	Long Run Marginal Cost
TAS	Tasmania
TMM	Typical Meteorological Month
TMY	Typical Meteorological Year
UQ	University of Queensland
VIC	Victoria
VO&M	Variable Operation and Maintenance
VOLL	Value-of-Lost-Load
WTG	Wind Turbine Generator

1 Introduction

The primary aim of this report is to help negotiate a Power Purchase Agreement (PPA) for the proposed hybrid gas-LFR plant at Collinsville, Queensland, Australia. The report's wider appeal is the techniques and methods used to model the NEM's demand and wholesale spot prices for the lifetime of the proposed plant.

To facilitate the PPA negotiations, this report produces the half-hourly dispatch of the plant's gas component and the associated half-hourly wholesale spot prices for the plant's node on National Electricity Market (NEM) given the yield from the plant's solar thermal component and a fixed total dispatch profile shown in Table 3. The total dispatch profile incorporates both gas and solar outputs and differs between weekdays and weekends.

Table 3: Proposed plant's total dispatch profile by hour of week

Time	Dispatch (MW)
Weekdays: 8am-10pm	30
Weekdays: 7am-8am	ramp from 0 to 30
Weekends	entire yield of the solar thermal component

The half-hourly yield profile for the solar thermal component of the plant is determined in our previous report (Bell, Wild & Foster 2014b). Three profiles are utilised to help to negotiate a PPA: solar thermal yield, gas dispatch and wholesale market spot price.

The executive summary provides an outline of the report.

2 Literature review

2.1 Introduction

This literature review helps us to develop the research question and inform the methodology to address the research question. This report uses two research questions to express the report's research requirements shown in Table 2.

What are the wholesale spots prices on the NEM given the plant's dispatch profile?

What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?

The literature review informs the development of forecasts for the National Electricity Market (NEM) for the 30 year lifetime of the proposed new solar thermal plant from 1 April 2017 to 31 March 2047 (RAC 2013).

Section 1 discusses demand forecasting. Section 2 discusses supply forecasting. Section 3 discusses dispatch and wholesale spot price forecasting while developing supporting research questions to investigate the interaction of the proposed plant with the NEM. Section 3 also introduces the Australian National Electricity Market (ANEM) Model that this report uses to calculate the dispatch and wholesale spot prices from the demand and supply forecasts in Sections 2 and 3.

2.2 Forecasting demand in the NEM for the lifetime of the proposed plant

This section discusses forecasting demand for the lifetime of the proposed plant.

There has been an increase in demand for electricity for over two decades. However, more recently, the Australian Electricity Market Operator (AEMO) has produced a number of demand forecasts that have over projected demand and have missed the general declining demand for electricity. This section focuses on reasons for AEMO's over-forecasting to help inform this report's demand forecasting.

There are many countervailing trends in the demand for electricity. For instance, there is uneven population growth across Australia, which will affect demand unevenly. The growth in the uptake of air conditioners is nearing a plateau, which will reduce the rate of increase in electricity demand. The price for electricity has increased rapidly over the last 10 years, which may see people become sensitive to price, so a price elasticity of demand starts to slow the rate of increase in demand. There are education campaigns to make people aware of their electricity use, which will reduce the rate of increase. Additionally, there is the ongoing shift in the economy from manufacturing to services, which will reduce demand because manufacturing is the most energy intensive sector.

Section 1 discusses the short and long-term drivers for demand. Sections 2 to 6 discuss structural changes to electricity demand that cause a permanent decrease in total demand. Section 7 discusses the ENSO cycle that causes temporary changes in total demand. Section 8 discusses the AEMO's over-forecasting of electricity demand.

2.2.1 Short-run and long-run drivers for electricity demand

Yates and Mendis (2009, p. 111) consider short-run drivers for demand due to weather, for instance in the short-run people can turn on fans or air conditions to meet changes in weather conditions. Yates and Mendis (2009, p. 111) list the following short-run electricity demand drivers:

- weather – air temperature, wind speed, air humidity and radiation;
- indoor environmental factors – indoor air temperature, wind speed and humidity;
- time of the day;
- day of the week;
- holidays;
- seasons;
- durations of extreme heat days;
- urban heat island effects;
- utilisation of appliances;
- person's financial position; and
- personal factors – clothing, physical activity and acclimatisation.

This report uses demand profiles from the years 2007-12, which incorporate all these short-run drivers for demand. We create a typical meteorological year (TMY) demand profile using the same twelve typical meteorological months (TMMs) derived in our yield report (Bell, Wild & Foster 2014b). This process ensures consistency between the reports, so both demand profile and yield profiles have consistent weather conditions.

Yates and Mendis (2009, p. 112) consider the following long-run drivers for demand:

- climate change;
- population growth, composition and geographic distribution;
- real price of electricity;
- the price of electricity relative to the price of gas;
- economic growth;
- real income and employment status;
- interest rates;
- renewal of building stock;
- households and floor space per capita;
- previous years consumption; and
- commercial and industrial electricity use.

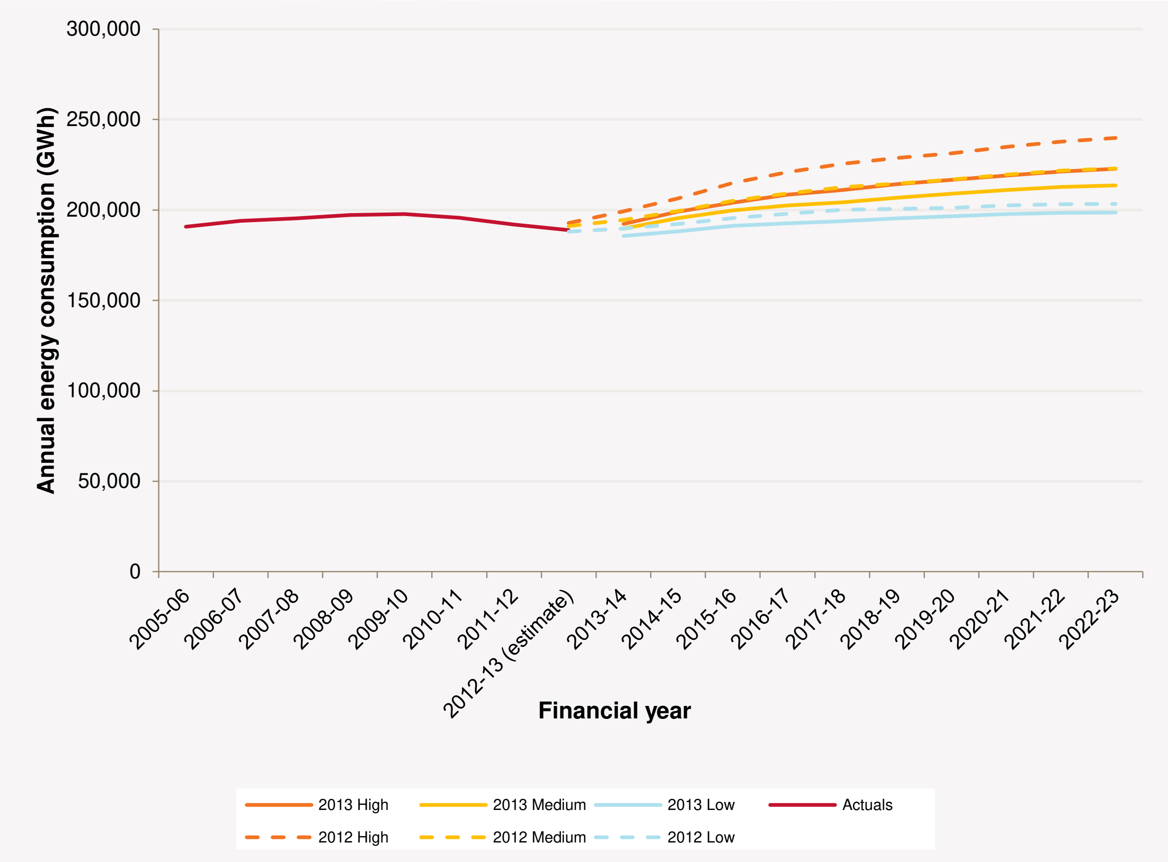
The AEMO's long-term forecasts incorporate these changes. Therefore, we could use the AEMO's forecasts to provide a growth rate for the TMY demand profile. However, the AEMO forecasts present two problems: consistently over-forecasting total demand in recent years and failure to cover the entire lifetime time of the proposed plant. Additionally, in the long-run people can install solar PV, solar water heaters and more energy efficient appliances and build more energy efficient housing. These have the effect of transforming the shape of the demand profile. Norris et al. (2014a) discuss the transformative effect of new technology changing the well-established accurate long-term predictions of electricity demand into disarray.

The next section discusses extending the definition of demand to account for these changes and the subsequent adjustment of the shape of the TMY demand profile.

2.2.2 Permanent transformation of demand: technological innovation redefining demand

Bell, Wild and Foster (2013) investigates the transformative effect of non-scheduled solar PV and wind turbine generation (WTG) on total electricity demand. The motivation for our study is a series of forecasts by the AEMO for increases in total demand but there is a continuing reduction in total demand see Figure 1.

Figure 1: 2013 NEFR annual NEM energy forecast



(Source: AEMO 2013a)

A number of factors contribute to these poor predictions, including: the Australian economy's continued switch from industrial to service sector, improvements in energy efficiency, the promotion of energy conservation, and mild weather induced by the La Niña phase of the ENSO cycle reducing the requirement for air conditioning. Section 2.2.7 discusses the ENSO cycle in more detail. Additionally, there is growing non-scheduled generation that is meeting electricity demand.

However, the AEMO's "Total demand" definition fails to account for non-scheduled generation. AEMO (2012, sec. 3.1.2) defines the "Total Demand" in the following way.

> *"Total Demand" is the underlying forecast demand at the Regional Reference Node (RRN) that is met by local scheduled and semi-scheduled generation and interconnector imports after excluding the demand of local scheduled loads and that allocated to interconnector losses.*
>
> *"Total Demand" is used for the regional price calculations in Dispatch, Pre-dispatch and Five-minute Pre-dispatch 5MPD, and to determine dispatch targets for generating units.*

Semi-scheduled wind farms are included in "Total Demand" but non-scheduled wind farms are excluded.

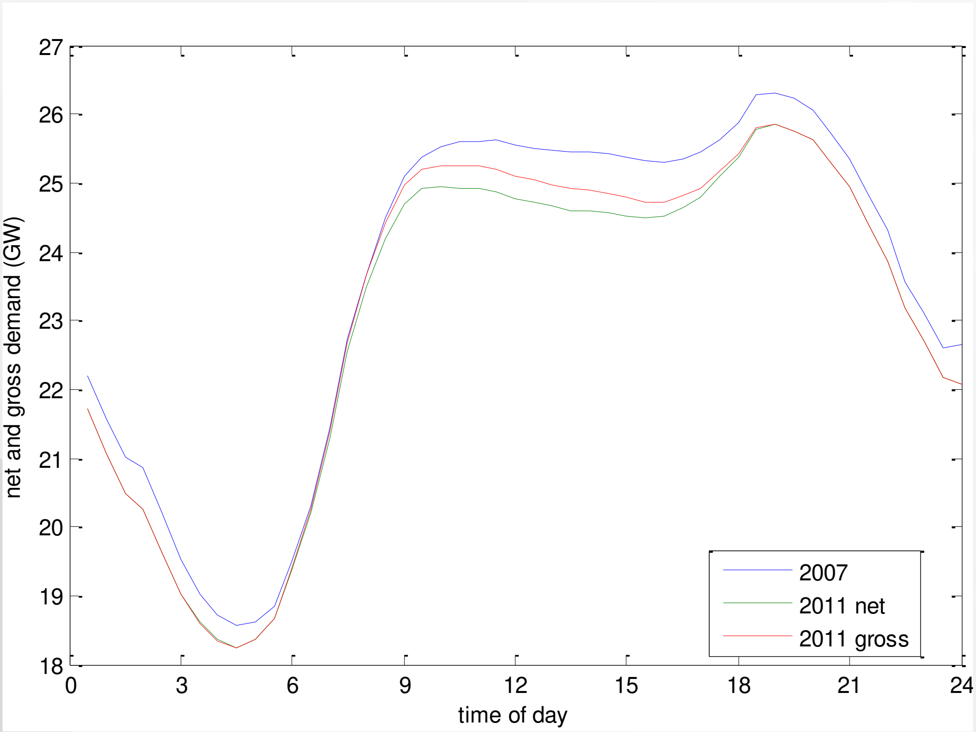
Bell, Wild and Foster (2013) introduce the concept of gross demand to incorporate non-scheduled generation. Equation 1 defines the term gross demand used in this report and relates the term to the AEMO's definition of "total" demand. Bell, Wild and Foster (2013) use the term "net demand" to describe AEMO's "total demand".

Equation 1: Demand - gross, scheduled and non-scheduled

gross demand = total demand + non-scheduled demand (this report)
gross demand = net demand + non-scheduled demand (Bell 2013)

In Figure 2, Bell, Wild and Foster (2013) compare the daily average net and gross demand for 2011 with 2007 The gross and net demand in 2007 is similar because the quantity of non-scheduled generation is relatively small, hence only one line is necessary to represent both. Figure 2 shows that the inclusion of non-scheduled solar PV and WTG accounts for a good portion of the decrease in net demand. This observation both helps explain the poor long-term forecasting performance of the electricity industry and requires the modelling of gross demand to consider the transformative effect on the net demand profile over time. This report grosses up the net demand TMY derived from the years 2007-12 for their respective levels of non-scheduled generation before calibrating the TMY demand profile to a consistent December 2013 level of non-schedule generation.

Figure 2: Comparing daily gross and net demand for 2007 & 2011



(Source: Bell 2013)

Equation 1 could be extended to include solar hot water heating in the definition of gross demand because this extension would help explain the decrease in net demand from 2007 to 2011 in the early hours of the morning shown in Figure 2. The solar hot water heaters displaced electric hot water heaters that traditionally used the off peak electricity during the early hours of the morning. This concept of gross demand could also incorporate energy efficiency. Section 7.3 in further research discusses incorporating the effect of solar hot water heating and energy efficiency on demand.

The McKinsey Global Institute (MGI 2014) expects the cost of solar PV installations to continue to decrease. Further installation will further depress the midday depression in “total demand” (net demand) in Figure 2. However, MGI (2013) and Norris et al. (2014a) expect battery storage to become economically viable in 2025, perhaps even earlier given sudden innovations. This timing is well within the lifetime of the proposed plant. Battery storage in conjunction with non-scheduled generation allows further growth in gross demand with little or no growth in “total demand”. Furthermore, the time shifting feature of battery storage is likely to moderate both the midday depression and the evening peak in total demand shown in Figure 2.

There are two consequences of the economic viability of battery storage for the proposed plant: no growth in total demand post 2025 and a transformation of the relative profitability of the LFR and gas components of the plant. The environment prior to battery storage provides relatively higher profitability for the gas component than the LFR and vice versa.

The AEMO (2014d) expects the capacity of the current generation fleet sufficient to meet any increase in total demand until after 2023, see Table 4, which is when battery storage is expected to allow growth in gross demand without an increase in total demand. The only exception is Queensland, which may have a reserve deficit in 2020-21. This is just short of the period when MGI (2013) expect battery storage to induce no growth in total demand that makes any new scheduled generation a very marginal proposition.

Table 4: Regional reserve deficit timings

	Queensland	NSW	Victoria	SA	Tasmania
Reserve deficit timings	2020-21	Beyond 2022-23	Beyond 2022-23	Beyond 2022-23	Beyond 2022-23

(Source: AEMO 2014d)

At least three factors could account for the AEMO projecting shorter reserve deficit timing for Queensland than the rest of the NEM: population growth, the production of liquefied natural gas (LNG) and other mining activity. Consistent with the AEMO’s projection, Table 5 shows the most likely percent growth in population across the NEM from 2006 to 2030 where the ABS(2008) expects Queensland to have a relatively high expected population growth compared to the rest of the NEM.

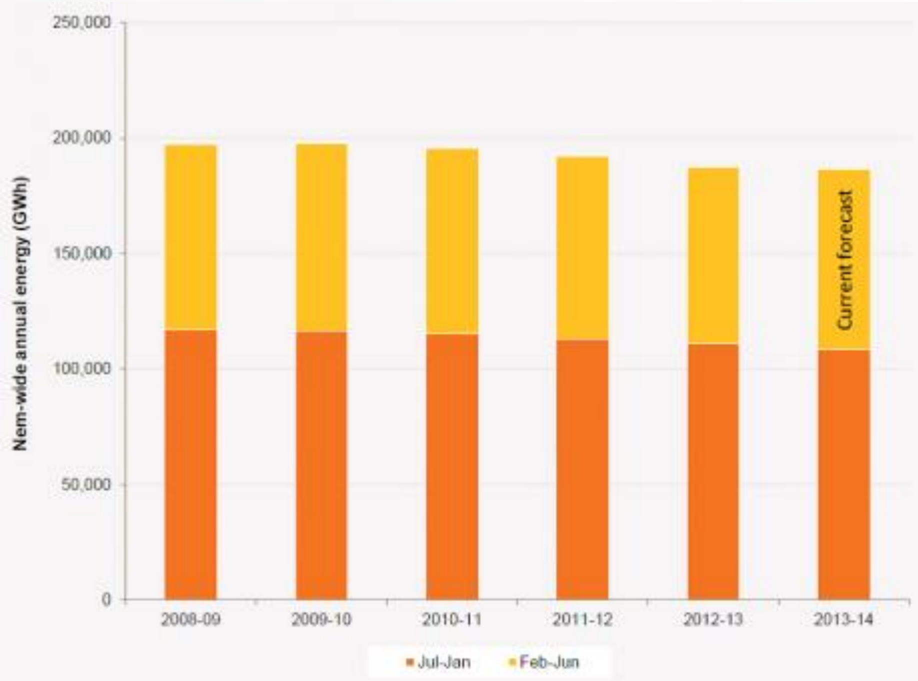
Table 5: Projected population growth from 2006 to 2030 across the NEM

Series B	Qld	NSW	Vic	SA	Tas	ACT	NEM
State	57%	27%	36%	24%	14%	29%	36%
Capital city	57%	32%	41%	25%	22%		38%
Balance of state	57%	20%	20%	21%	8%		32%

(Source: ABS 2008)

However, Figure 2, in a quarterly update (AEMO 2014d) of the Electricity Statement of Opportunities (ESO) (AEMO 2013a), shows the demand across the NEM continues to decrease. This literature review discusses reasons for the poor forecast further. For instance, Section 2.2.5 discusses energy efficiency and the switch to high density living that will reduce "total demand" per capita. Additionally, Section 2.2.3 discusses the production of liquefied natural gas in Queensland, the resources bubble and associated decline in manufacturing that will also reduce "total demand" per capita.

Figure 3: Six-year comparison of energy consumption



(AEMO 2014d)

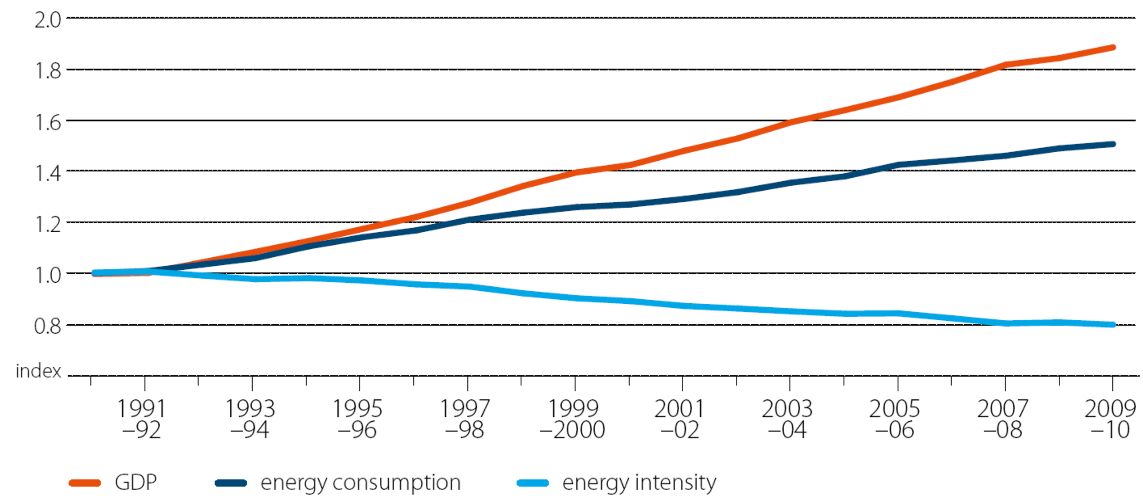
2.2.3 Permanent transformation of demand: manufacturing decline

Figure 4 shows that growth in energy consumption has remained below the growth in Gross Domestic Product (GDP) and energy-intensity has been declining. Energy-intensity is the ratio of energy used to activity in the Australian economy. Ball et al. (2011, p. 8) discuss how declining energy-intensity is a worldwide phenomenon.

Shultz and Petchey (2011, p. 5) consider the decline in energy-intensity is due to two factors:

- improving energy efficiency associated with technological advancement; and
- shifting industrial structure toward less energy-intensive sectors.

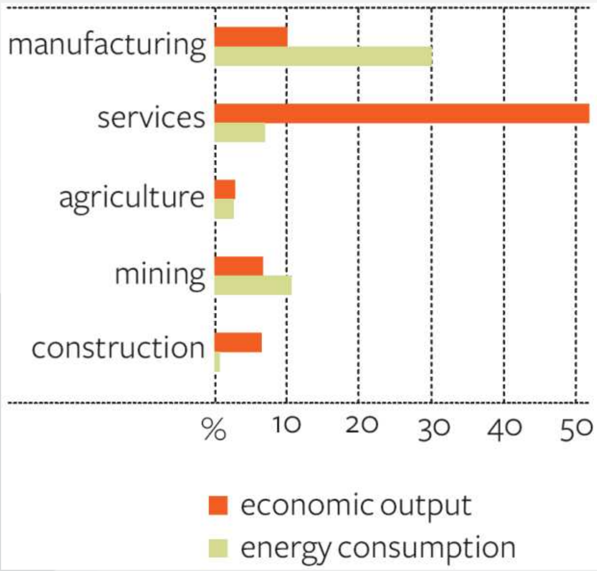
Figure 4: Intensity of Australian energy consumption



(Source: Schultz & Petchey 2011, p. 5)

The improvement in energy efficiency is likely to continue. Figure 5 compares the percentage share of economic output and of energy use for different industries. Manufacturing is the most energy intensive industry and the service industry is one of the least intensive industries. Mining is less energy intensive than manufacturing. Therefore, the increase in the size of both service and mining industries and decrease in the size of the manufacturing industry accounts for some of the decline in energy-intensity.

Figure 5 Shares of energy consumption and economic output 2005-06



(Source: Sandu & Syed 2008, p. 4)

There is a temporary increase in electricity demand from increased construction activity in Queensland to establish the infrastructure ensuing from the resources bubble and more specifically, to make the gas trains to liquefy natural gas (LNG) for export.

However, the resources bubble via the exchange rate mechanism accelerates the decline in manufacturing. The bubble causes Australia's exchange rate to appreciate. This appreciation makes Australia's manufactured exports relatively more expensive to buyers overseas and makes manufactured imports relatively less expensive to buyers in the domestic market. In addition, the gas price increases ensuing from the export of LNG will further accelerate the decline of the manufacturing sector and, in turn, reduce "total" demand for electricity.

The latest major manufacturing closures include:

- car manufacturing in SA, NSW and VIC
- Alcoa's smelter and roll mills in VIC and NSW

These manufacturing industries are unlikely to return after the collapse of the resources bubble because there are on-going moves toward more trade liberalisation. The consequence is a persistent reduction in "total demand". The reduction in "total demand" caused by the manufacturing decline affects the NEM unevenly with NSW and VIC having the largest declines in absolute terms.

Sections 2.2.3 and 2.3.2 discuss further the consequences of the resources bubble and LNG export for the NEM and the proposed plant.

2.2.4 Permanent transformation of demand: smart meters

This section discusses how smart meters providing customers with dynamic pricing can help customers reduce demand for electricity at peak times and increase public engagement in energy conservation.

Smart meters allow retailers to collect high frequency data automatically on customers' electricity usage and customers to monitor their own use of electricity. Smith and Hargroves (2007) discusses the introduction of smart meters, the ensuing public engagement and the substantial reduction in peak demand being achieved. Currently in Australia, the requirement to meet peak demand drives transmission and distribution investment decisions. This peak demand is usually between 3 pm and 6 pm in most 'Organisation for Economic Cooperation and Development' (OECD) countries. Georgia Power and Gulf Power in Florida, USA, have installed smart meters resulting in Georgia Power's large customers reducing electricity demand by 20-30 per cent during peak times and Gulf Power achieving a 41 per cent reduction in load during peak times. Zoi (2005) reports on California's experience of tackling the growing demand for peak summer power using a deployment of smart meters with a voluntary option for real time metering that uses lower tariffs during off peak times and higher tariffs during peak times with a 'critical peak price' reserved for short periods when the electricity system is really stressed. A key finding was a 12-35 per cent reduction in energy consumption during peak periods. Moreover, most Californians have lower electricity bills and 90 per cent of participants support the use of dynamic rates throughout the state.

Australia is slow in deploying smart meters, and Queensland is particularly slow, but the deployment across the NEM within the lifetime of the proposed plant is a reasonable expectation. Norris et al. (2014b) provide a cost-benefit justification for an Australian wide rollout of a smart grid.

2.2.5 Permanent transformation of demand: energy efficiency

Improvements in energy efficiency are an ongoing process and expected to reduce "total" demand in the NEM. However, the state based approach to energy efficiency has hampered improvements. Nevertheless, during the lifetime of the plant more effective energy efficiency policy and deployment is expected.

Hepworth (2011) reports how AGL and Origin Energy called for a national scheme rather than state based schemes because compliance across the different states' legislations is costly. However the National Framework for Energy Efficiency (NFEE 2007) instituted by the Ministerial Council on Energy (MCE) claims significant progress. But in a submission to the NFEE (2007) consultation paper for stage 2, the National Generators Forum (NGF 2007) comments on the progress since stage 1 of the NFEE: *"Progress in improving the efficiency of residential and commercial buildings can best be described as slow and uncoordinated, with a confusion of very mixed requirements at the various state levels. … Activities in areas of trade and professional training and accreditation, finance sector and government have been largely invisible from a public perspective"*. The NGF (2007) states that the proposals for stage 2 are modest and lack coordination and national consistency. Therefore, there is disagreement between the MCE and participants in the NEM over coordination in the NEM.

The star rating of appliances by Equipment Energy Efficiency (E3 2011) is an example of a campaign that is visible and easy to understand, which is moot with some success and addresses information asymmetry. As discussed, the introduction of smart meters and flexible pricing has engaged customers in other countries. This public engagement by smart meters can provoke a much wider interest in the conservation of electricity to include energy efficiency. Both Origin Energy (2007) and NGF (2007) acknowledge that the MEPS established for refrigerators and freezers, electric water heaters and air conditioners are effective and support the expansion of MEPS to include other appliances. An expansion of MEPS will further constrain growth in "total demand".

In another submission to the consultation paper, Origin Energy (2007) calls for the NFEE to focus on non-price barriers to energy efficiency that the price signal from a carbon price is unable to address. Origin Energy considers that the following items are suitable for direct action to remove non-price barriers:

- education/information campaigns;
- minimum Energy Performance Standards (MEPS);
- phasing out electric hot water systems;
- incandescent light bulb phase out; and
- building standards.

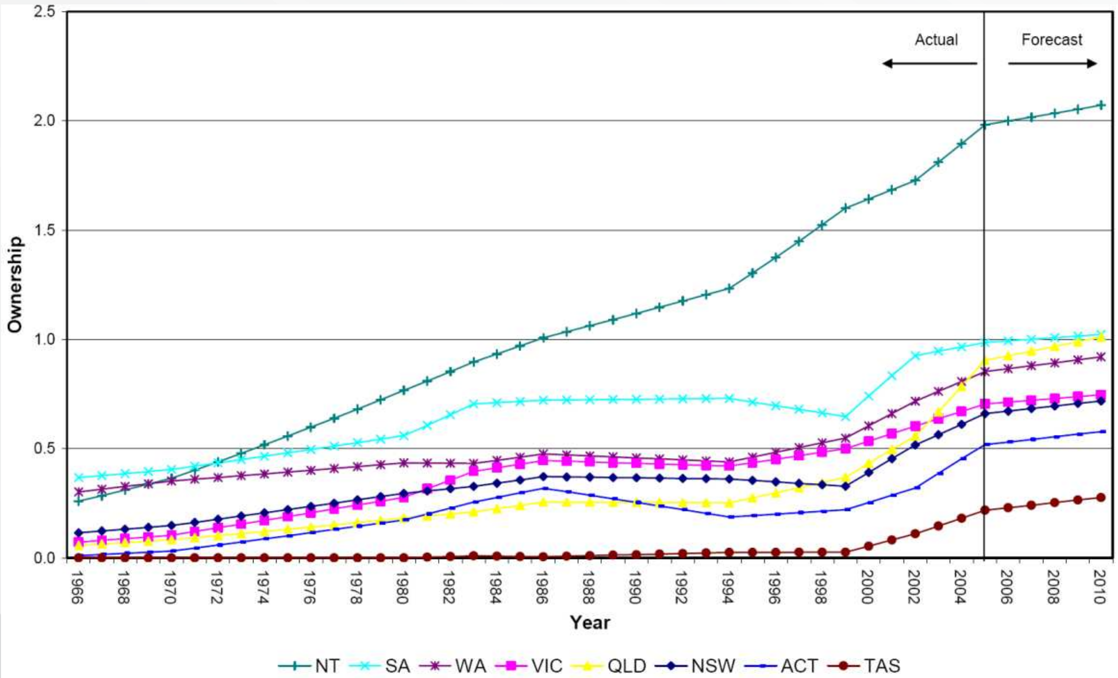
Stevens (2008, p. 28) identifies the need for raising public awareness of electricity demand and shaping public opinion to combat climate change but Origin Energy (2007) considers public education/information campaigns are considerably underfunded. Since 2008, there have been campaigns to improve peoples' awareness of the relation between climate change and electricity use. We expect this to continue during the lifetime of the proposed plant and permanently affect people's behaviour.

NGF (2007) states that water heating accounts for 30% of household electricity and 6% of total stationary energy use. Section 2.2.2 discusses how the installation of solar hot water systems maintains gross demand but permanently reduces "total" demand.

Both Origin Energy (2007) and NGF (2007) express concern about the phase out of incandescent light bulbs, being in favour of the phase out but better consultation prior to the phase out may have prevented some adverse and unintended consequences. Such as, the poor light rendition and high failure rate of substandard imported compact fluorescent lights (CFL), which caused some people to adopt halogen down lights that have higher energy use than incandescent light bulbs. However, the phasing out of incandescent bulbs has permanently reduced "total" demand.

The MEPS will reduce the amount of energy new air conditioners use, thereby reducing demand for electricity. However, Figure 6 shows increases in ownership of air conditioners across all states, which will increase demand for electricity. There was a rapid growth in air conditioner ownership from 2000 to 2005 but from 2006, there was an expected slowing in growth. The NT shows a considerably different trajectory to the other states but lies outside the NEM region. In summary, MEPS will constrain the growth in electricity demand from air conditioners.

Figure 6: National Ownership of Air Conditioners by State



(Source: NAEEEC 2006, p. 9)

The changes in building standards have engendered an improvement in new housing energy efficiency. Yates and Mendis (2009, p. 121) discuss how increased urban salinity and ground movement damage induced by climate change will accelerate building stock renewal, leading to a long-run reduction in demand for electricity. However, the projected growth in the number of households exceeds the projected growth in population, which means fewer people sharing a household and increasing electricity demand above population growth. Table 6 shows the projected growth in the number of households across the NEM from 2006 to 2030. Table 7 shows the projected growth in the number of households above the projected growth in population. Table 7 is the difference between Table 6 and Table 5.

Table 6: Uneven projected household growth from 2006 to 2030 across the NEM

Series II	QLD	NSW	VIC	SA	TAS	ACT	NEM
State	68%	37%	44%	31%	22%	38%	45%
Capital city	66%	40%	50%	31%	28%		46%
Balance of state	70%	32%	31%	32%	18%		43%

(Source: ABS 2010)

Table 7: Projected household growth above population growth from 2006 to 2030

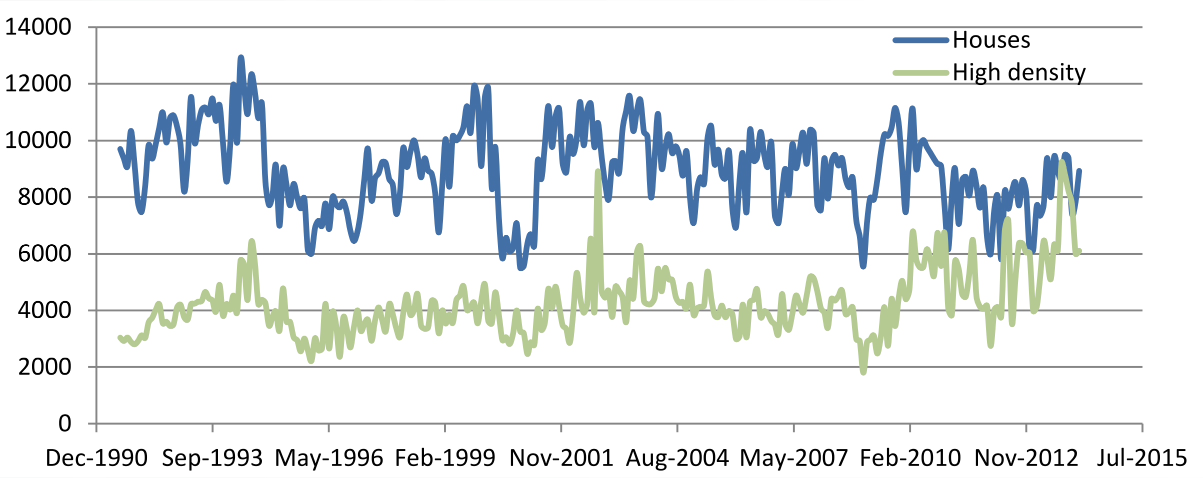
Series II - Series B	QLD	NSW	VIC	SA	TAS	ACT	NEM
State	11%	10%	8%	7%	8%	9%	9%
Capital city	9%	8%	9%	6%	6%		8%
Balance of state	13%	12%	11%	11%	10%		11%

Series I, II and III household projections use the assumptions of the Series B population projection in Table 5. The household projection assumptions in Table 6 are those for Series II of the ABS (2010). ABS (2010) considers Series II the most likely growth scenario where Series I and III represent lower and higher growth scenarios, respectively.

While the number of people per house decreases, Building Research Advisory New Zealand (BRANZ Limited 2007, pp. 28-9) discusses how there is an increase in the size of the average house in Australia where the new standard house has four bedrooms and two bathrooms. The increases in size of house will increase demand for electricity. While house size has become larger, the section size has become smaller, which increases the heat island effect, that is, the reduction in greenery around a suburb to moderate temperature swings. The heat island effect will also increase the demand for electricity. Nevertheless, the increase in the number of swimming pools acts to moderate the heat island effect.

However, since BRANZ Limited (2007, pp. 28-9) made their observations, there has been a distinct switch from individual houses to high-density living. Figure 7 shows the number of private residential approvals and compares house with high-density approval numbers. This switch to high-density living will act to reduce the average size of housing stock and moderate growth in total demand.

Figure 7: Private residential approvals



(Source: ABS 2014)

2.2.6 Permanent transformation of demand: price awareness

Australia still enjoys relatively low electricity prices by international standards but the commodity boom has driven prices higher for fossil fuels, which has in turn driven electricity prices higher (Garnaut 2008, pp. 469-70). At low electricity prices people are insensitive to price rises but at higher prices, people become much more sensitive to price increases to the extent that people decrease their use of electricity. The higher price example means that the price elasticity of demand for electricity has increased or is more elastic. The price elasticity of demand is the percentage increase or decrease in quantity demanded in relation to the percentage increase or decrease in price. The higher prices for electricity could see a higher elasticity of demand operating, which would moderate further increases in demand for electricity.

In the past, the cost of electricity was very low. Therefore, it never attracted much attention and people considered it “small change”. However, once an awareness of electricity use is developed, a demand hysteresis effect takes hold, so even if prices decrease the awareness of electricity use remains. This demand hysteresis produces a permanent modification of behaviour. Additionally, the other permanent transformations of demand discussed in the previous sections act to solidify demand hysteresis.

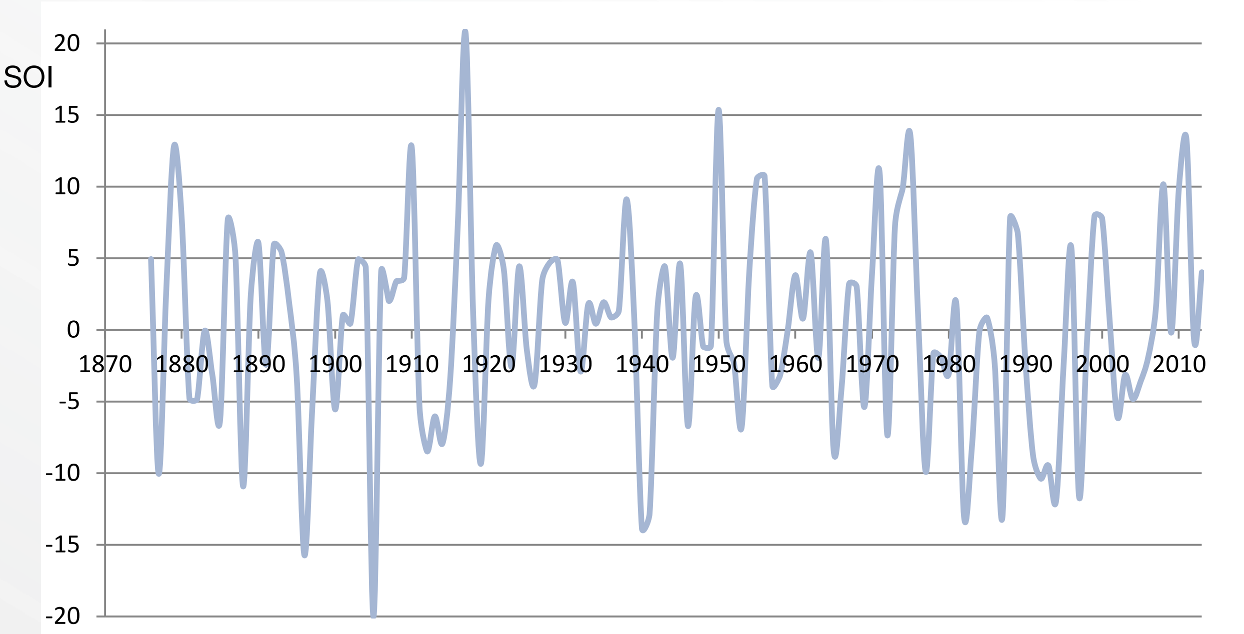
2.2.7 Irregular cyclical transformation of demand: ENSO

We have already discussed the ENSO cycle in detail in our previous report regarding plant yield (Bell, Wild & Foster 2014b). However, we discuss the ENSO again but give a purely demand side interpretation to inform the poor forecasting performance of the electricity industry. In the ENSO cycle, the *El Niño* phase relative to the *La Niña* phase increases solar intensity, temperature and pressure and reduces humidity. The overall *El Niño* effect is to increase both solar yield and electricity demand.

Figure 8 shows the mean annual southern oscillation index (SOI) for 1875-2013 where a positive SOI indicates a La Niña (BoM 2014b) bias and the negative SOI indicates an El Niño (BoM 2014a) bias.

The recent demand forecasts have overestimated demand during the *La Niña* bias period since 2007. In contrast, the prior period 1976 to 2007 has a strong *El Niño* bias. Forecasters who assume a continuing *El Niño* bias would over estimate demand.

Figure 8: Mean annual SOI 1875-2013



(Source: BoM 2014c)

2.2.8 Over-forecasting bias and NSP profit correlation

NSPs' capital expenditure determines their profits, which encourages them to build more infrastructures. If peak demand increases, the NSPs are legally obliged to build more infrastructure to accommodate the demand and the NSPs profit from accommodating the demand. This remuneration process encourages NSP to provide demand forecasts that indicate increases in demand. The AEMO previously relied on the NSPs demand forecasts but the NSPs continual over forecasting of demand called into question their reliability. The AEMO now commissions independent forecasts but they are still over-forecasting "total" demand.

2.2.9 Demand Summary

This section introduced the concept of gross demand to inform the discussion of the numerous structural changes to demand that are permanently reducing the AEMO's "total" demand. The irregular ENSO cycle contrasts with the numerous permanent structural changes and may enter a high demand phase for a while before returning to a low demand phase.

The reserve deficit timing for Queensland 2020-21 (AEMO 2013a) has two main drivers: Queensland population growth and the resources bubble. In particular, there is the construction in developing gas trains and new coalmines and their supporting infrastructure. However, both the recent shift to high-density living and energy efficiency improvements will mute demand growth from the first driver. For the second driver, the higher export linked price for gas and appreciated exchange rate induced by the resources bubble will accelerate the decline of Australian manufacturing and consequently reduce NEM wide “total demand”.

This report assumes the current AEMO forecasts lack the consistent over-forecasting bias correlated to NSP profit motives but the massive permanent structural changes in demand makes demand forecasts based on previous trends fraught with problems, so this report assumes continued growth in gross demand but no growth in the AEMO’s “total” demand.

2.3 Forecasting supply in the NEM for the lifetime of the proposed plant

This section discusses forecasting supply or generation capacity of the NEM for the lifetime of the proposed plant. There are four major factors influencing investment decision for new generation: “total” demand, climate change policy, fossil fuel prices and the decreasing costs of renewable generation. This section also discusses delivery of supply via the network shown in Section 8.

Table 4 discusses the regional reserve deficit timings where AEMO (2013a) expects surplus capacity in the NEM beyond 2022-23. This is the period when battery storage is expected to become economically viable, which will in effect create further surplus generation because storage enables the continual utilisation of the cheapest forms of generation during off peak periods and the use of arbitrage to sell during peak periods. This process will initially compete directly with the more expensive forms of generation such as peak-load gas generation, so making future investments in peak-load gas generation risky.

2.3.1 Reserve deficit in Queensland and manufacturing decline

The exception to the NEM’s surplus capacity beyond 2022-2023 is Queensland that has a reserve deficit timing of 2019-20 for 159 MW (AEMO 2013a). However, the August 2014 Electrical Statement of Opportunities (AEMO 2014c) shows that Queensland’s 2019-20 projected reserve deficit has evaporated. AEMO now projects a generation reserve adequacy to beyond 2023-24 for all states in the NEM. This continued over forecasting is consistent with the predictions in our draft report.

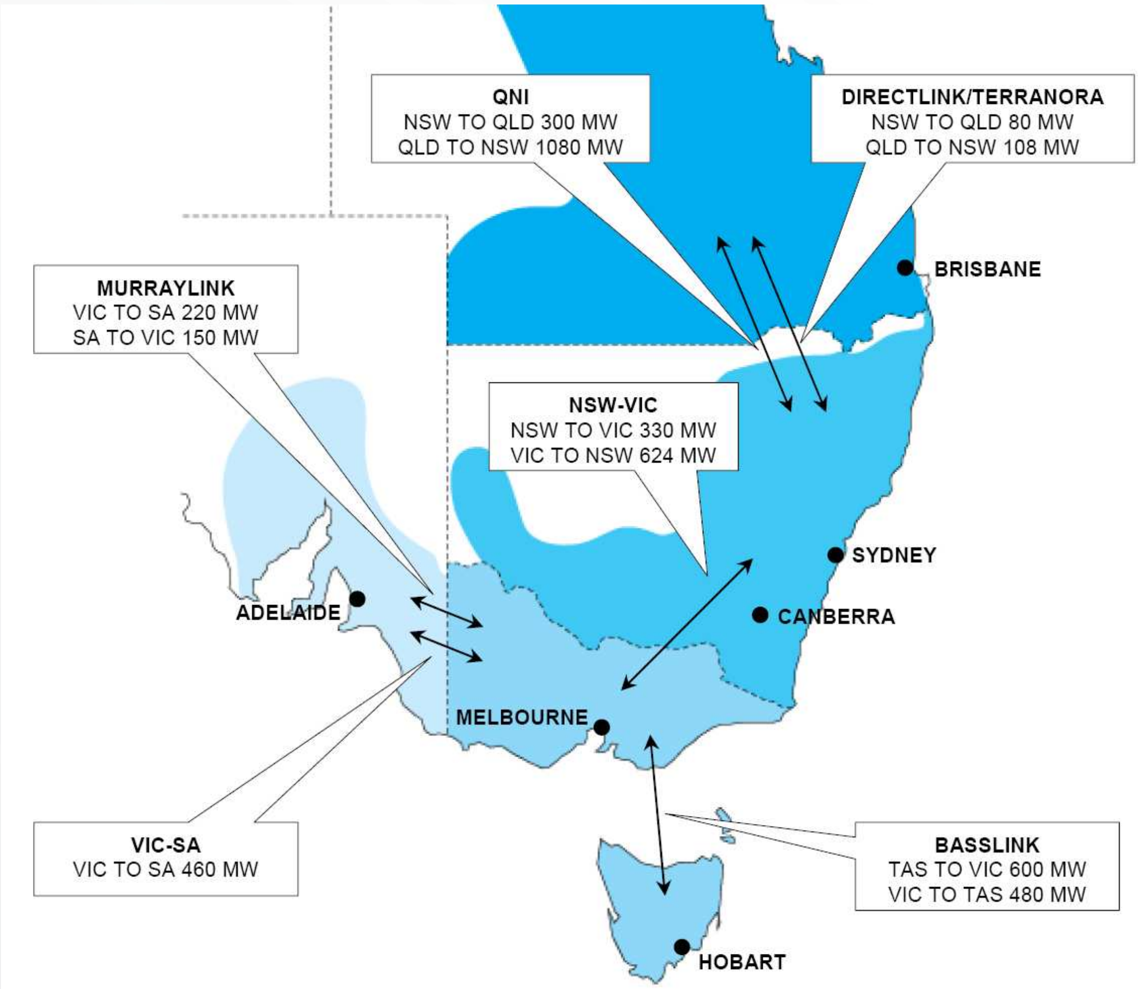
Nevertheless, even if the previous reserve timing still held, the lifetime of a plant built to meet the reserve timing would fall within the period of economically viable storage, which would create a great deal of uncertainty for the plants revenue stream.

Additionally, major manufacturing closures elsewhere in the NEM frees-up supply for export to Queensland. These major closures include:

- car manufacturing in SA, NSW and VIC
- Alcoa’s smelter and roll mills in VIC and NSW

However, Queensland is currently a net exporter of electricity to NSW and the interconnector constraints in Figure 9 reflect this role. Whether there is sufficient free capacity to import electricity to cover the reserve deficit of 159 MW, is unknown. However, economically viable storage would make this constraint issue immaterial. Section 2.3.4 discusses transmission investment.

Figure 9: Interconnectors on the NEM



(Source: Tamblyn 2008, p. 7)

2.3.2 LNG export prices hampering gas generation's potential as a bridging technology

Gas could replace coal as a "bridging technology" to reduce GHG emissions over the next few decades because gas only produces about half of the GHG emissions of coal (IEA 2011, pp. 18-22). However, the feasibility of gas as a bridging technology comes under question for two reasons:

- the proposed removal of the carbon price; and
- liquefaction of natural gas for the export

The proposed removal of a carbon price exacerbates investment uncertainty for gas generation because coal generators become relatively more economical than gas generators without a carbon price.

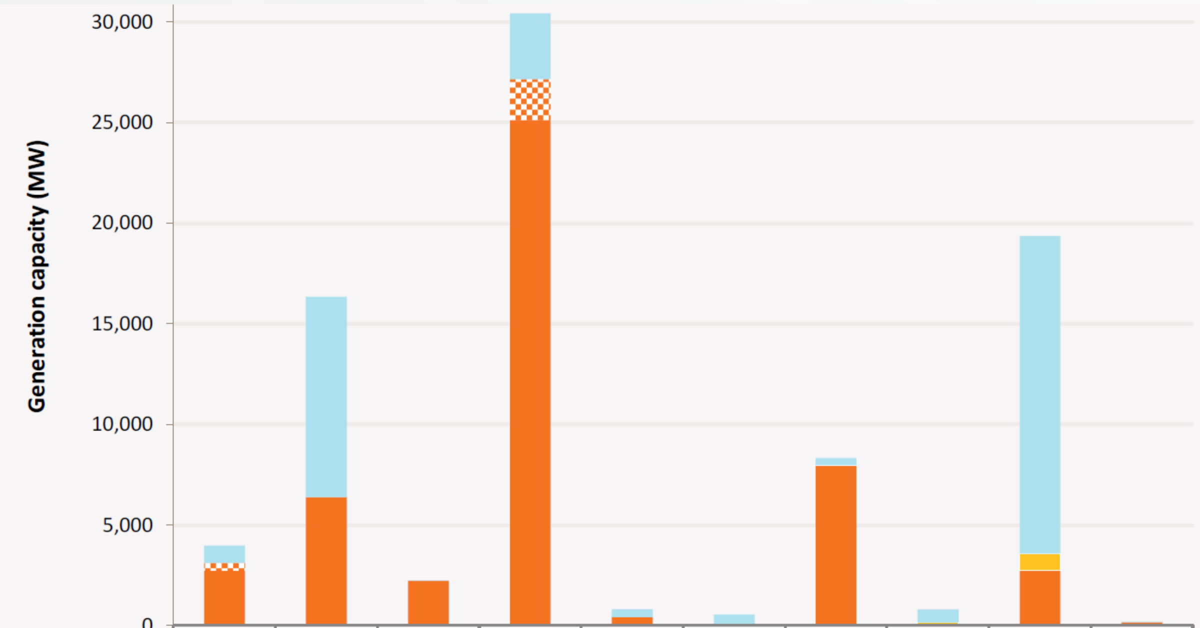
Section 2.3.2 discusses the liquefaction of natural gas for the export. This export of LNG creates an international linkage for gas prices in the NEM. Therefore, the traditional domestically determined price of $3-4/GJ could rise to an internationally determined price potentially lying in the range of $8.00/GJ to $10.00/GJ for base-load gas generation with an additional add-on rate of up to 25% for peak-load gas generation. Figure 10 shows the existing and proposed generator projects by generation type. The feasibility of the proposed gas generation projects based on historical gas prices will most probably prove infeasible with the newly international determined price for gas.

Figure 10 shows a pattern consistent with the sudden change in gas prices and uncertainty surrounding a carbon price affecting the feasibility of new gas-fired power generation, namely:

- a large number of proposed OCGT projects but no committed projects for CCGT, OCGT and other gas; and
- the withdrawal of existing generation.

The withdrawal is the 385MW Swanbank E Gas Power Station which will cease operation for up to three years from 1 October 2014 and return to service before the projected timing of reserve deficits in Queensland (AEMO 2014d).

Figure 10: NEM existing and proposed projects by generation type (MW)



	Combined Cycle Gas Turbine	Open Cycle Gas Turbine	Gas other	Coal	Biomass	Geothermal	Water	Solar	Wind	Other
Proposed	860	9,955	15	3,270	387	550	337	639	15,799	10
Committed	-	-	-	-	-	-	1	146	834	-
Existing (Withdrawn)	385	-	-	2,015	-	-	-	-	-	-
Existing	2,726	6,384	2,226	25,144	419	-	7,987	2	2,742	172

(Source: AEMO 2014d)

However, from a global climate change perspective it is immaterial whether gas is burnt in Australia or overseas because either case will provide “bridging technology”. In fact selling gas overseas may prove a better global climate change adaptation because Australia has more economically viable renewable energy resources than many Asian countries, which relatively reduces Australia’s need for gas as a bridging technology.

2.3.3 WTG: Low demand to wind speed correlation inducing price volatility

Figure 10 shows both the largest proposed generation and committed generation is from WTG. This raises three issues:

- Uncertainty over and the potential removal of the Large Renewable Energy Target (LRET) and future uncertainty over a carbon price inducing investment uncertainty;
- demand and WTG supply timing mismatch; and
- wholesale spot price volatility.

Simply absorbing the entire 15,799 MW of proposed and 834 MW of committed WTG needs careful consideration because there is a high correlation of demand between states and a high correlation of wind speed between states but little correlation between demand and wind speed between states, see Table 8.

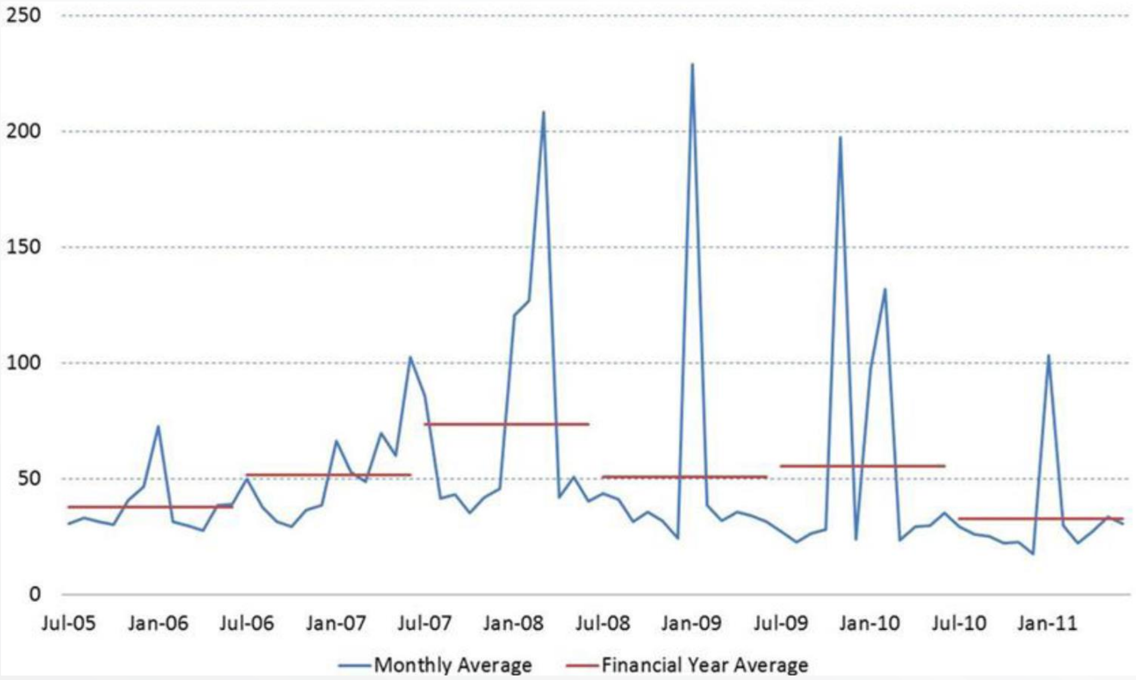
Table 8: Correlation of wind speed and demand

		Demand					Wind speed			
		NSW	QLD	SA	TAS	VIC	NSW	SA	TAS	VIC
Demand	NSW	1								
	QLD	0.83	1							
	SA	0.81	0.67	1						
	TAS	0.72	0.54	0.58	1					
	VIC	0.89	0.75	0.85	0.78	1				
Wind Speed	NSW	0.08	0.11	0.05	0.1	0.07	1			
	SA	-0.16	-0.08	-0.07	-0.15	-0.16	0.34	1		
	TAS	-0.06	0.04	-0.06	-0.04	-0.04	0.31	0.24	1	
	VIC	-0.08	-0.05	-0.06	0	-0.05	0.44	0.64	0.47	1

(Source: Bannister & Wallace 2011, p. 15)

A consequence of this demand and WTG supply mismatch are volatile wholesale spot prices. Wholesale spot prices are sensitive to the addition of such a large penetration of WTG whose marginal cost is nearly zero. This adversely affects the profitability of existing plant and affects the investment decisions for new plant. For instance, the state with Australia's largest penetration of WTG, South Australia, has experienced both increased volatility and reduced average wholesale spot prices. The AMEC chairman (Pierce 2011) confirms this reduction in the average spot price for electricity in SA, see Figure 11.

Figure 11: Average wholesale spot price in South Australia per MWh



(Source: Pierce 2011, p. 7)

However, the AMEC chairperson also discusses the increase in volatility in spot price in Table 8 where there have been increases in half-hours with negative spot prices and increases in half-hours with spot prices above $5,000 and $300 per MWh. The increase in negative spot prices continues but the increase in high positive spot prices saw a downturn in 2010. Therefore, the increasing penetration of WTG provides economic benefit to electricity users. Table 6: South Australia's wholesale spot prices

Table 9: South Australia's wholesale spot prices

Year	Number of half-hour prices in South Australia			
	Above $5,000/MWh	Above $300/MWh	Below $0/MWh	Below -$300/MWh
2006	1	62	1	0
2007	3	78	10	2
2008	52	78	51	3
2009	50	97	93	8
2010	24	58	139	18

(Source: Pierce 2011, p. 8)

The large baseload capacity in SA relative to demand and the limited ability to export surplus electricity to VIC combine to exacerbate the effect of the large penetration of WTG in SA on the wholesale spot price when windy conditions can occur during periods of low demand and baseload capacity is unable to adequately: ramp-down or shut-down to accommodate WTG. Wholesale spot price volatility solutions include either increasing

- the thermal capacity of the interconnectors from SA to VIC; or

- the utilisation of fast ramping, start-up and shut-down capacity such as CCGT and OCGT gas plant in SA instead of the more traditional base-load coal and gas thermal plant.

However, the previous section discusses the current adverse investment climate for OCGT investment, which makes new investment unlikely.

Nevertheless, AEMO and ElectraNet (AEMO & ElectraNet 2013) identified the need to increase the thermal capacity of the SA to VIC interconnector in July 2016. AEMO's and ElectraNets' (AEMO & ElectraNet 2013) decision to invest in expanding the SA-VIC interconnector are net market benefit through significant reductions in generation dispatch costs over the longer term. This allows the export from SA to VIC, more generation from WTG and thermal generation in SA when low demand and windy conditions arise in SA. This results in cheaper electricity for VIC, helps address the negative spot prices in SA, and makes use of faster ramping generation in VIC rather than any correlation between SA's wind's and VIC's demand.

Further to system stability and wholesale spot price volatility, Parkinson (2011) claims that there are successful large installations in a number of countries where variability has not posed a major problem. For instance Jones (2011, p. 91) discusses the East German company 50Hertz that has 37% of electricity supplied by WTG. However, 50Hertz can sell and send surplus electricity to Poland, Czech Republic, Austria, Denmark or the former West Germany, which would reduce the likelihood of negative prices.

Nevertheless, the transmission grid in Europe is more of dense mesh structure. In contrast, the NEM's transmission grid is more a long string stretching nearly the entire east coast of Australia. The mesh structure is better suited to absorbing intermittent generation. As discussed above, the solution to SA's high WTG penetration problems was improving the interconnectedness between SA with VIC. Making the NEM's transmission grid more mesh like or increasing thermal capacity of the interconnectors could extend this solution.

However, installing the entire proposed WTG in Figure 10 would take the NEM's penetration of WTG far above 37% for the company 50Hertz, assuming no increase from other forms of generation. The percentage of WTG within the European grid is much smaller than 37%. Absorbing all the proposed WTG within the NEM potentially poses unknown stability problems. There are at least three solutions:

- increase the diversity of renewable generation;
- increase distributed generation on net surplus demand nodes; and
- energy storage.

The proposed plant at Collinsville is part of this drive for diversity in renewable energy that will help system stability.

Placing distributed generation on nodes of the grid where there is net deficit generation or net demand surplus, that is, more demand than generation. Many of the proposed wind farms are to go into such areas, especially in NSW.

The arbitrage opportunities for energy storage are particularly good from WTG with both extreme negative and positive wholesale spot prices shown in Figure 11. Energy storage also provides a means to defer transmission network investment induced by large penetration of WTG. However, the separate ownership of generation and networks presents an obstacle to energy storage owners' ability to capture the full economic benefits of energy storage deployment. This separation of ownership will slightly delay energy storage deployment sometime after it becomes economically advantageous to the NEM (MGI 2013).

2.3.4 Energy storage deferring transmission infrastructure investment

Appendix A presents the NEM's transmission network that the ANEM model uses to address the research questions in this report. This section justifies the simplifying assumption that the transmission topology stays the same for the lifetime of the proposed plant.

We assume the topology of the transmission network in Appendix A stays the same for the lifetime of the proposed plant for four reasons:

- Reserve capacity
- Energy storage
- Over-forecasting demand and gold-plating
- Real time measurement

The August 2014 Electricity Statement of Opportunities (AEMO 2014c) regional reserve deficit timings show the existing supply sufficient until after 2023-24 at which time energy storage becomes economically viable to enable investment deferment in network infrastructure.

Compounding this excess capacity, Section 2.2.8 discusses the over-forecasting of demand by NSP, which lead to building network infrastructure in excess of actual demand or gold plating. Finally, there is the switch from normal to real-time rating of the thermal capacity of transmission lines that will allow better use of the existing infrastructure. See Transmission Network Service Providers (TNSP 2009, p. 4) for details.

However, we acknowledge that the installation of further WGT may require expanding the capacity of the transmission lines for the participants in the NEM to increase their net benefit from WGT until energy storage becomes economical viable.

2.3.5 Supply Summary

Uncertainty surrounding generation investment includes falling total demand, changing climate change policy and increasing fossil fuel prices. Additionally, there is the decreasing costs of renewable generation promoting a wait and see attitude.

Appendix B discusses the known closures and mothballing of generation plant and future deployment of WGT and transmission grid investments but beyond this time, we assume that no further investment will occur to meet "Total demand" for the lifetime of the proposed plant. We base these assumptions on the permanent structural changes in total demand discussed in Section 2 and the advent of economically viable energy storage within the next 10 years allowing investment deferment in both transmission and generation.

The recent moves by the current Federal Government to either remove or significantly water-down the LRET that supports deployment of WTG, is unpopular in Australia and runs contrary to the increasing penetration of WTG internationally. Therefore, we assume increases in WTG in the arising research questions. Additionally, there is the remote possibility of gas in a bridging technology role where gas-fired generators simple replace some of the decommissioned coal-fired generators. Therefore, the research questions examine wholesale market prices with and without gas in a bridging role.

2.4 Forecasting wholesale spot prices for the lifetime of the proposed plant using the ANEM model

The ANEM model determines the dispatch and wholesale spot prices from the interaction of the NEM's demand and supply discussed in Sections 2.2 and 2.3. Appendix B, in Section 9, discusses the ANEM model in detail and Appendix A, in Section 8, shows the network structure used by the ANEM model. The following description provides a simplified computer input-output overview of the ANEM model.

The inputs of the ANEM model are:

- half hourly electricity "total demand" for 52 nodes in the NEM;
- parameter and constraint values for 68 transmission lines and 316 generators, which ignores de-commissioned plant over the period 2007-2014;
- carbon price;
- fossil fuel prices; and
- network topology of nodes, transmission lines and generators.

The outputs of the ANEM model are:

- wholesale spot price at each node (half hourly),
- energy generate by each generator (half hourly),
- energy dispatched by each generator (half hourly),
- power transmission flow on each transmission line (half hourly), and
- carbon dioxide emissions for each generator (daily).

Collinsville is situated on node number 3 called *'North'* in Figure 19 in Appendix A. Section 2.2.1 briefly describes the preparation of "total demand" using a typical meteorological year (TMY) selected from the years 2007-12. Section 3.2 discussed the data preparation in more detail.

2.4.1 The effect of the plant's proposed dispatch profile on wholesale spot prices in the NEM

The ANEM model helps study the interaction of the proposed plant with the NEM. However, the 30 MW output of the plant is tiny relative to 6,400 MW, the average total demand in Queensland for the proposed operating time (AEMO 2014a), and so is unlikely to affect wholesale spot prices. Locational marginal prices (LMP) are the wholesale spot prices for the proposed plant's node. If LMPs are insensitive to the dispatch of the plant, the plant lacks market power. Consequently, the plant is a pure price taker. Therefore, we can optimise its dispatch independently of its interactions with the NEM. Section 7.2 in further research discusses investigating the sensitivity of the wholesale spot prices to the dispatch of the proposed plant.

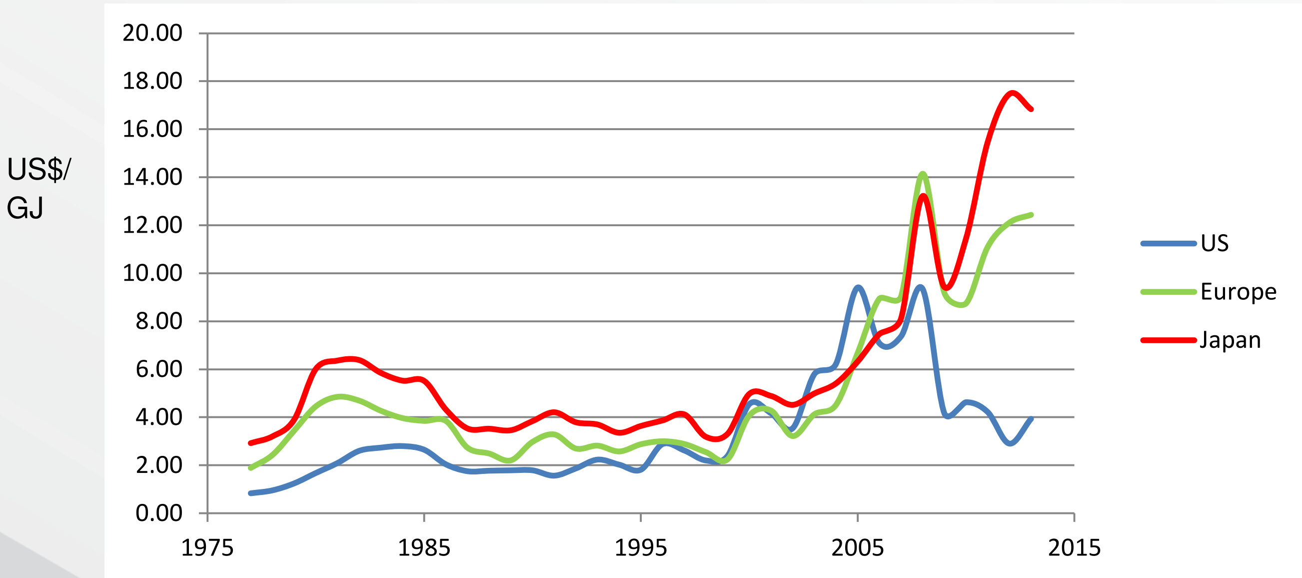
2.4.2 The effect of gas prices on wholesale spot prices

The profit of the plant's LFR component is largely subject to the weather and wholesale spot prices and since its marginal costs are nearly zero, dispatching its entire yield is profit maximising. In comparison, the gas component's supply is from a stranded asset whose supply is \$5/GJ, so independent of what happens with international gas prices. This gives the gas component an advantage compared with other gas generators whose gas prices would be subject to international prices and their ability to secure long-term gas supply contracts.

However, the profit of the proposed plant is indirectly subject to the market price of gas because the price of gas and coal largely determine the wholesale spot price of electricity. Nevertheless, an increase in gas prices relative to coal would produce a substitution from gas to coal generation, which would moderate increases in electricity prices. The sensitivity of the plant's profits to changes in gas prices requires investigation. Such a sensitivity study requires a range of possible future gas prices. Hence, we investigate gas prices.

Currently, the pricing of gas on the east coast of Australia is going through a dramatic transformation because liquefied natural gas (LNG) exports link the once isolated domestic market with the rest of the world. The AEMC (2013) discusses how this linkage will determine the east coast's market price for gas and that price is unlikely to return back to the historic levels of $3-4/GJ. Figure 12 compares Japan's LNG and US's and Europe natural gas prices in nominal US$ per gigajoule.

Figure 12: Comparing Japan's LNG and Europe's and US's natural gas prices



(Source: World Bank 2014)

Figure 12 can provide some indication of the range of future gas prices in eastern Australia but factors affecting the price in the US, Europe and Japan require considering. In the US, there are restrictions on the export of gas and there is a surplus of gas in the domestic market. Therefore, the current low price of gas in the US is of little guidance in estimating the future cost of gas in Australia but if the US reduced the export restriction, the price of gas in Japan is likely to decline. The closure of nuclear plants in Japan and Germany after the Fukushima accident has caused price increase in both Japan and Europe but more sharply in Japan.

Figure 12 shows the price of LNG in Japan. The Wood, Carter and Mullerworth (2013) estimates of the cost to convert natural gas to LNG and transport from Australia to Asia is about $5 to $6 per gigajoule. Therefore, the "export parity" price would be about $11/GJ. This parity price contrasts sharply with the recent domestic prices of $3-4/GJ.

BREE (2013) discusses seven contracts for gas settling between $7-8/GJ and one contract, the latest, settling between $8-9/GJ. In a high growth scenario, BREE (2013) estimates a gas price above $10/GJ by 2023. BREE (2013) uses LNG netback pricing in export parity calculations, that is, *the LNG Free On Board (FOB) export price less the costs of liquefaction and transportation.*

There is the possibility that countries may take substantial action over climate change during the lifetime of the plant. This would engender a larger switch from coal to gas because gas generation can act as a bridging technology. Additionally, China may simply want to address its air pollution problem. This would also engender a switch from coal to gas. Both cases would put upward pressure on LNG prices. There is also the current spike in LNG prices induced by closure of their nuclear plants in both Japan and Germany. However, putting downward pressure on prices are the new processes that enable access to new deposits of gas, whose supply has yet to develop fully, and the US has a surplus supply of gas that the US is preparing for export.

However, the above analysis of the World Bank (2014) and BREE (2013) data only provides a single gas price for the NEM region but there are many gas prices across the NEM region and we use the ANEM model in this report to calculate electricity prices that can use regionally based gas prices. Therefore, we use regionally based gas prices calculated by a gas price model called ATESHGAH (Wagner 2004; Wagner, Molyneaux & Foster 2014). This model considers the effects of LNG exports on domestic gas prices in the NEM and the results are generally in agreement with the World Bank (2014) and (BREE 2013). These regionally based gas prices allow us to address the research questions realistically. Consequently, the research questions express the gas price as a range to reflect their regional distribution.

The following research questions address the sensitivity of the plant to gas prices.

- How sensitive are wholesale spot prices to a gas price change from a reference gas price of between $5.27/GJ to $7.19/GJ to a high gas price of between $7.79/GJ to $9.71/GJ for base-load gas generation (depending upon nodal location) with a 25% add-on rate for peak-load gas generation?
- How sensitive is the plant's revenue to these changes in gas prices?

Section 3 discusses how the ANEM model addresses these research questions.

2.5 Conclusion

The literature review has both established the research questions and provided direction for the methodology to address these questions.

2.5.1 Research questions

The report has the following overarching research questions:

> *What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?*
>
> *What are the wholesale spots prices on the NEM given the plant's dispatch profile?*

The literature review has refined the latter research question into four more specific research questions ready for the methodology:

- *What are the half-hourly wholesale spots prices for the plant's lifetime without gas as a bridging technology?*
    - *Assuming a reference gas price of between \$5.27/GJ to \$7.19/GJ for base-load gas generation (depending upon nodal location;) and*
    - *for peak-load gas generation of between \$6.59/GJ to \$8.99/GJ; and*
    - *given the plant's dispatch profile*
- *What are the half-hourly wholesale spots prices for the plant's lifetime with gas as a bridging technology?*
    - *Assuming some replacement of coal with gas generation*
- *How sensitive are wholesale spot prices to higher gas prices?*
    - *Assuming high gas prices are between \$7.79/GJ to \$9.71/GJ for base-load gas generation (depending upon nodal location); and*
    - *for peak-load gas generation of between \$9.74/GJ to \$12.14/GJ; and*
- *What is the plant's revenue for these reference gas prices?*
- *How sensitive is the plant's revenue to gas as a bridging technology?*
- *How sensitive is the plant's revenue to the higher gas prices?*
- *What is the levelised cost of energy for the proposed plant?*

3 Methodology

This chapter operationalises the research questions arising from the literature review. Section 2.4.2 discusses the estimation of the expected lower and upper bounds for domestic gas prices to determine a sensitivity of the NEM's wholesale spot prices and plant's revenue to gas prices. Five operationalised research questions form the main section headings in this methodology chapter:

- *What is the expected TMY dispatch of the proposed plant given the plant's dispatch profile for hours of the week and expected TMY yield of the LFR?*
- *What are the half-hourly wholesale spots prices for the plant's lifetime without gas as a bridging technology?*
    - *Assuming a reference gas price of between $5.27/GJ to $7.19/GJ for base-load gas generation (depending upon nodal location;) and*
    - *for peak-load gas generation of between $6.59/GJ to $8.99/GJ; and*
    - *given the plant's dispatch profile*
- *What are the half-hourly wholesale spots prices for the plant's lifetime with gas as a bridging technology?*
    - *Assuming some replacement of coal with gas generation*
- *How sensitive are wholesale spot prices to higher gas prices?*
    - *Assuming high gas prices are between $7.79/GJ to $9.71/GJ for base-load gas generation (depending upon nodal location); and*
    - *for peak-load gas generation of between $9.74/GJ to $12.14/GJ; and*
- *What is the plant's revenue for these reference gas prices?*
- *How sensitive is the plant's revenue to these higher gas prices?*
- *What is the levelised cost of energy for the proposed plant?*

3.1 What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?

We calculate the half-hourly dispatch of the proposed plant for a TMY and present the dispatch as three components:

- Gross yield from the LFR
- The dispatch from the gas generator
- The parasitic load

We derive the TMMs for the TMY and the gross yield in our previous report on yield (Bell, Wild & Foster 2014b). We selected the TMMs from the years 2007-13. Based on the yield projections, RAC decided to use the entire yield from the LFR. Therefore, no spillage is required and we can simple report the gross yield for the LFR.

We calculate the TMY dispatch of the gas generator from the difference between the LFR yield and the requirement to keep total dispatch at a minimum of 30 MW during the higher demand periods during the weekdays. Table 3 specifies in detail the combined gas-LFR dispatch by hour of week. The dispatch of the gas generators allows us to calculate the gas usage. We assume a 36.6% energy efficiency rate for the gas generator to convert gas energy into electrical energy based on Parson Brinckerhoff (2013). We assume the price for the plant's gas supply is $5.00/GJ in 2014 indexed by an inflation rate of 2.5% thereafter. The plant's gas supply is a stranded asset. Therefore, the plant's gas supply is immune from the gas price changes investigated in the gas price sensitivity analysis. The fuel price, energy conversion rate and associated heat rate, together with assumed values of Variable Operation and Maintenance Costs (VO&M - $0.98/MWh sent-out), auxiliary load (4.00%) and emissions intensity (0.551 tC02/MWh) produced a Short Run Marginal Cost (SRMC) of $56.1208/MWh.

We developed the TMY parasitic load in our previous report (Bell, Wild & Foster 2014b). We treat the gross yield from the LFR and the parasitic load separately because the yield from the LFR may be subject to additional support.

3.2 What are the half-hourly wholesale spots prices for the plant's lifetime without gas as a bridging technology?

We make the following assumptions:

- a reference gas price of between $5.27/GJ to $7.19/GJ for base-load gas generation (depending upon nodal location)
- for peak-load gas generation of between $6.59/GJ to $8.99/GJ
- given the plant's dispatch profile
- the WTG penetration increases during the lifetime of the plant
    - 2017's WTG capacity equals 2013's capacity
    - 2018-22's WTG capacity doubles 2013's capacity
    - 2023-47's WTG capacity triples 2013's capacity
- an inflation rate of 2.5% and indexed gas prices for inflation
    - The base year for the indexation is 2014
    - The gas prices in the research questions refer to 2014 gas prices

The proposed gas-LFR plant is on the NEM's "North" node in Figure 19, that is, node 3. The following discussion refers to the wholesale spot prices for the North Node.

The ANEM model forecasts wholesale spot prices for the lifetime of the proposed plant from electricity demand and electricity supply forecasts. Sections 2.2 and 2.3 in the literature review discuss demand and supply, respectively. Appendix B discusses the ANEM methodology in detail and Appendix A presents the ANEM's topology of the transmission lines, nodes, generators and load serving entities.

However, the market definitions of demand and supply differs between the ANEM model and AEMO (2012, sec. 3.1.2) in one respect. The ANEM model includes large non-scheduled generation when calculating the "market" wholesale spot price whereas the AEMO's total [market] demand excludes large non-scheduled generation. Section 2.2.2 discusses AEMO's "total demand" in more detail. Therefore, the AEMO's total market demand requires grossing up by the non-scheduled generation. Sections 3.2.1.1 and 3.2.1.2 discuss grossing-up AEMO's "total demand" with large non-scheduled WTG and other large non-scheduled generation, respectively.

Section 2.3 establishes the most likely change in supply scenario as an increase in WTG capacity. Therefore, during the lifecycle of the proposed plant we assume an increase in

WTG. Additionally, Section 2.3 establishes the unlikeliness of increases in gas generation capacity.

Section 2.4.2 presents the case for a lower bound and upper bound for gas prices to help establish the limits for the sensitivity of electricity wholesale spot prices to gas prices. This section's methodology is for the baseline case that uses a reference gas price of between \$5.27/GJ to \$7.19/GJ for base-load gas generation (depending upon nodal location) with a 25% add-on rate for peak-load gas generation producing gas prices of between \$6.59/GJ to \$8.99/GJ. The next section provides the methodology to investigate the sensitivity of spot prices to an increase in gas prices.

Subsections 1 and 2 respectively discuss the methodology for the demand and supply forecasts in more detail.

3.2.1 Developing a TMY of market demand in the NEM for the lifetime of the proposed plant

This section discusses the methodology to produce the TMY total demand profile for the NEM from the years 2007-2012. This methodology uses a four-step process to develop a TMY normalised total demand profile.

- Grossing-up total demand with large non-scheduled WGT
- Grossing-up total demand with other large non-scheduled generation
- Load shaving the proposed plant's dispatch from the total demand at node 3
- Add the parasitic load to node 3
- Developing a TMY total demand profile using the proposed plant's TMMs

3.2.1.1 Grossing-up total demand with large non-scheduled WGT

The first step involves grossing-up for the AEMO's half-hourly demand for the NEM's 50 demand nodes from 2007 to 2012 for the non-scheduled WGT. Equation 2 describes the relationship amongst AEMO's total market demand and ANEM's market.

Equation 2: Grossing-up total demand 2007-12

$$d_g(t, n) = d_t(t, n) + w(t, n) + o(t, n)$$

Where:

d_g = gross demand (MW)
t = time (half hourly)
n = node
d_t = total demand (MW)
w = large non-scheduled WTG (MW)
o = other larger non-schedule generation (MW)

We calculate the power from large non-scheduled WGT using AEMO (2014f) five-minute non-scheduled generation output data by wind farm for the year 2013. The year 2013 includes the Macarthur and Musselroe wind farms commissioned in late 2012 and 2013, respectively. We averaged the five-minute data across six intervals to produce half-hourly output by wind farm. We aggregated this half-hourly data across the non-scheduled generators located on the same node to produce half-hourly data by node. Table 10 shows the large non-scheduled wind farms included in this report. Appendix A provides diagrams of the node locations.

Table 10: Large non-scheduled wind farms included in modelling

Wind Farm	*Node Location*	*Capacity MW*
Capital	Canberra	140.7
Cullerin Range	Canberra	30.0
Yambuk	South West, VIC	30.0
Portland	South West, VIC	102.0
Waubra	Regional, VIC	192.0
Challium Hills	Regional, VIC	52.5
Canundra	South East, SA	46.0
Lake Bonney 1	South East, SA	80.5
Starfish Hill	Adelaide	34.5
Wattle Point	Mid-North, SA	90.8
Mount Millar	Eyre Peninsula	70.0
Cathedral Rock	Eyre Peninsula	66.0
Woolnorth	Burnie, TAS	139.8
	Total	*1,074.8*

(Source: AEMO 2014f)

Table 11 shows the large WGT non-scheduled wind farms excluded from modelling in this report because AEMO lacks data on these wind farms as they lack a *Supervisory Control and Data Acquisition* (SCADA) connection with the AEMO system. However, the contribution from these wind farms is 3.0 per cent of total wind capacity, so ameliorating any concerns about their omission.

Table 11: Large non-scheduled wind farms excluded from modelling

Wind Farm	*Node Location*	*Capacity MW*
Windy Hill	Far North, QLD	12.0
Crookwell	Marulan, NSW	4.8
Blayney	Mt Piper, NSW	9.9
Toora	Morwell, VIC	21.0
Wonthaggi	Morwell, VIC	12.0
Codrington	South West, VIC	18.2
Hepburn	Regional, VIC	4.1
	Total	*82.0*
	% of total wind capacity	*3.01%*

Table 12 shows the semi-scheduled wind farms included in this report but we exclude semi-scheduled wind from the grossing-up process in this section because semi-scheduled wind farms are included in AEMO's definition of total [market] demand discussed in Section 2.2.2 and shown in Equation 1. However, this section presents Table 12 to enable comparison with the non-scheduled wind farms in Table 10 and Table 11. The large wind generation modelling in this report comprises thirteen non-scheduled and fourteen semi-scheduled wind farms with a combined capacity of 2,639.9 MW, which represents 96.99 per cent of total installed capacity of operational wind farms in the NEM at the end of 2013. Section 3.2.2 discusses further semi-scheduled generation.

Table 12: Large semi-scheduled wind farms included in modelling

Wind Farm	*Nodal Location*	*Capacity MW*
Gunnings Range	Canberra	46.5
Woodlawn	Canberra	48.3
Oaklands Hill	South West, VIC	67.2
Macarthur	South West, VIC	420.0
Lake Bonney 2	South East, SA	159.0
Lake Bonney 3	South East, SA	39.0
Snowtown 1	Mid-North, SA	98.7
Hallett 1	Mid-North, SA	94.5
Hallett 2	Mid-North, SA	71.4
Clements Gap	Mid-North, SA	56.7
Waterloo	Mid-North, SA	111.0
North Brown Hill	Mid-North, SA	132.3
The Bluff	Mid-North, SA	52.5
Musselroe	Hadspen, TAS	168.0
	Total	*1,565.1*
	Combined Total	*2,721.9*

(Source: AEMO 2014e)

3.2.1.2 Grossing-up total demand with other large non-scheduled generation

We also applied the same procedures outlined in Section 3.2.1.1 to gross-up nodal based total demand by the output from non-scheduled generation sourced from generation other than wind generation. Table 13 lists the other large non-scheduled generation and their nodal location. The other generation include hydro, bagasse (e.g. electricity production from sugar cane mills) and diesel generation.

There are two major rationales for including this output in the nodal based grossing-up of total demand. First, a number of non-scheduled hydro and diesel generators included in Table 13 are included in the ANEM model as generators. These generators include Butlers Gorge, Clover, Cluny, Paloona, Repulse, Rowallan and Angaston power stations – see Appendix A. Second, the additional incremental nodal demand associated with other non-scheduled generation listed in Table 13 but not directly included in the ANEM model can be easily accommodated by the generation included in the model, as their output and contribution to nodal demand in the grossing up operation are not large in magnitude. This corresponds to the output of Broken Hill, Invicta Mill, Pioneer Mill, Rubicon, Warragamba, Rocky Point and Callide A power stations.

To ensure that our treatment of non-scheduled generation matches between the outputs sourced from both WTG and other sources of generation, we have used the output from the generation listed in Table 13 for calendar year 2013. This matches the approach adopted in relation to the treatment of the output of non-scheduled WTG listed in Table 10. This will ensure that the non-scheduled components used to gross-up total demand are consistent across different types of non-scheduled generation listed in Tables 10 and Table 13. As with the case of non-scheduled wind generation, five-minute production data associated with the generators listed in Table 13 was also sourced from AEMO (2014f) , which provides five-minute generation output data by generator for the years 2007-13.

Table 13: Other large non-scheduled generation

Name	*Node Location*	*Generation Type*
Butlers Gorge	Tarraleah TAS	Hydro
Clover	Dederang VIC	Hydro
Cluny	Liapootah TAS	Hydro
Broken Hill GT 1	Tumut NSW	Diesel
Broken Hill GT 2	Tumut NSW	Diesel
Invicta Mill	Ross QLD	Sugar Cane (Bagasse)
Paloona	Sheffield TAS	Hydro
Pioneer Mill	Ross QLD	Sugar Cane (Bagasse)
Repulse	Liapootah TAS	Hydro
Rowallan	Sheffield TAS	Hydro
Rubicon	Melbourne	Hydro
Warragamba	Sydney	Hydro
Rocky Point	Moreton South QLD	Biomass (Bagasse/Wood Chips)
Callide A	Central West QLD	Coal
Angaston 1	Mid-North SA	Diesel
Angaston 2	Mid-North SA	Diesel

(Source: AEMO 2014f)

3.2.1.3 Load shaving the proposed plant's dispatch from the total demand at node 3

In this step, we load shave the proposed plant's gross dispatch from node 3 of the total market demand profile derived in the above step. Section 3.1 discusses the methodology to calculate the plant's gross dispatch.

3.2.1.4 Add the parasitic load to node 3

In this step, we add the proposed plant's parasitic load to node 3 of the total market demand profile derived in the above step. Section 3.1 also discusses the methodology to calculate the plant's parasitic load.

3.2.1.5 Developing TMY normalised total demand profile using proposed plant's TMY

Developing the TMY for total demand involves selecting the 12 typical meteorological months (TMMs) from the years 2007-12 of the normalised total demand. We determined these 12 TMMs in our yield report (Bell, Wild & Foster 2014b) to represent the typical yield from the proposed plant's LFR. This method provides consistency between the reports and maintains focus on the dispatch of the proposed plant. Therefore, this report's TMY represents typical yield rather than the typical demand.

3.2.2 Forecasting supply for the lifetime of the proposed plant

This report uses latest *Electricity Statement of Opportunities* (ESO) (AEMO 2013a, 2014c) to provide a forecast of supply. After the time horizon of the ESO, we assume energy storage to play a significant role in determining AEMO's "total demand" both by deferring investment in generation and transmission (MGI 2013; Norris et al. 2014a). Additionally, energy storage plays a significant role in allowing growth in "gross demand" without growth in "total demand", that is, electricity produced and consumed within the NEM region but outside the market. Section 2 discusses in more detail.

As discussed above, we incorporate both semi-scheduled and large non-scheduled wind generation operational over the period 2007 to 2013 in the ANEM model as generators. However, in the ANEM model, we aggregate the output of the wind farms by node calculated by summing the output of all non-scheduled and semi-scheduled wind farms located within a particular node. Thus, we are not modelling the individual wind farms themselves but are aggregating their output within a node to derive an aggregated nodal based wind generation source. Moreover, we are restricting attention to those nodes that contain operating wind farms. We exclude assessment of the impact of proposed wind farms located at nodes that do not contain operational wind farms such as Armidale, Marulan, Wellington and Yass nodes in NSW.

We assume default bids of $10,000/MWh for non-dispatched wind generation. $10,000/MWh is the Value-of-Lost-Load (VOLL). The ANEM model over writes the default bid when the output of the wind generation source exceeds 10MW at any node. We calculate output value by summing the half-hourly output traces associated with both non-scheduled and semi-scheduled wind farms located in each node. These half-hourly output traces are averages of five-minute data contained in AEMO (2014e, 2014f).

When the default setting is overridden, the nodal based wind ‘entities’ are dispatched according to short run marginal cost coefficients calculated from averages of equivalent cost coefficients of all wind farms located in the node. These coefficient values lie in the range of $3.39/MWh to $4.69/MWh, thus representing some of the cheapest sources of generation when dispatched.

3.3 What are the half-hourly wholesale spots prices for the plant’s lifetime with gas as a bridging technology?

- Assuming some replacement of coal with gas generation

In this question, we make the same assumptions as in the previous research question but assume replacement of old coal-fired plant with Combined Cycle Gas Turbine (CCGT) plant for the period 2025-47. Appendix B discusses the replacements in detail.

3.4 How sensitive are wholesale spot prices to higher gas prices?

This research question investigates the sensitivity of wholesale spot prices to an increase in gas prices from the reference gas prices to prices in the range of $7.79/GJ to $9.71/GJ. These prices are for base-load gas generation but add an extra 25% for peak-load gas generation. Research Question 2, in Section 3.2, calculates the wholesale spot prices for the reference gas prices. We use Research Question 2’s methodology to calculate the wholesale spot prices for the higher gas prices. Then we perform the sensitivity analysis.

In this high gas price scenario, we assume that gas plays no role as a bridging technology.

3.5 What is the plant’s revenue for the reference gas prices?

This research question calculates the plant’s revenue using the dispatch calculated in research question 1 and the wholesale spot prices in research question 2. We make the following assumptions:

- 11% discount factor in the net present value calculations

- Net present valuation in 2014
- 30 year plant lifetime from 1 April 2017 to 31 March 2047

3.6 How sensitive is the plant's revenue to gas as bridging technology?

This research question uses the dispatch and wholesale spot prices from the previous research questions to evaluate the effect of the replacement of older vintage coal-fired plant with base-load CCGT plant on revenue.

3.7 How sensitive is the plant's revenue to higher gas prices?

This research question also uses the dispatch and wholesale spot prices from Research Question 5 to evaluate the effect of a gas price increase on revenue.

3.8 What is the Levelised Cost of Energy?

In this section, we develop the methodology to calculate the levelised cost of energy for the proposed plant to determine strike prices for power purchases agreements (PPA) to meet the dispatch profile in Table 3. The section also produces both preliminary calculations for use in Section 4.8.

The wholesale market profit (WMP) in Equation 3 is the difference between wholesale market revenue (TR) and total variable cost (TVC) in Equation 4 and Equation 5: Variable cost, respectively. Note that in relation to wholesale market operations, the restriction of cost to total variable cost reflects the use of this concept to underpin supply offers by generators and price determination in the power flow solution employed in the wholesale market modelling used in this report.

Equation 3: Wholesale market profit

$$WMP_t = TR_t - TVC_t$$

Equation 4: Total revenue

$$TR = \sum_{t=1}^{N} P_t \times Y_t$$

Equation 5: Variable cost

$$TVC = \sum_{t=1}^{N} \alpha \times Y_t + \beta \times Y_t^2,$$

where P_t is the nodal price confronting the generator at time t, Y_t is the production from the generator at time t, α is a $\left(\frac{\$}{MWh}\right)$ linear coefficient and β is a $\left(\frac{\$}{MW^2h}\right)$ quadratic coefficient of generator's total variable cost function defined in Wild, Bell and Foster (2012b app. A). Note further that we escalate both α and β by the rate of inflation over the lifetime of the generation asset.

3.8.1 Total variable costs

In this report, total variable costs [measured in terms of $(\$/h)$] (TVC_t) for a generator is defined as the sum of fuel cost $(FUELCOST_t)$ and variable (O&M) expenses $(VOMC_t)$. We ignore any variable carbon costs in this report.

Equation 6: Total variable costs

$$\begin{aligned} TVC_t &= FUELCOST_t + VOMC_t \\ &= fuelprice * (\kappa + \varphi * Y_t + \zeta * Y_t^2) + om_v * Y_t \\ &= (fuelprice * \kappa) + [(fuelprice * \varphi) + om_v] * Y_t + (fuelprice * \zeta) * Y_t^2 \\ &= \gamma + \alpha * Y_t + \beta * Y_t^2, \end{aligned}$$

Where

- Y_t is generator output produced in $MW's$;
- κ is the intercept term of the heat rate function measured in terms of (GJ/h);
- φ is the linear term of the heat rate function measured in terms of (GJ/MWh);
- ζ is the quadratic term of the heat rate function measured in terms of (GJ/MW^2h).
- $fuelprice$ is the price of fuel and is measured in terms of $(\$/GJ)$;
- om_v is a constant parameter measured in terms of $(\$/MWh)$ that captures the incremental cost of generation associated with operation and maintenance costs that are a direct function of generation;
- $\gamma = (fuelprice * \kappa) = \left(\left(\left(\frac{\$}{GJ}\right) \times \left(\frac{GJ}{h}\right)\right)\right) = \left(\frac{\$}{h}\right)$;
- $\alpha = [(fuelprice * \varphi) + om_v] = \left[\left(\frac{\$}{GJ} \times \frac{GJ}{MWh}\right) + \frac{\$}{MWh}\right] = \left(\frac{\$}{MWh}\right)$; and
- $\beta = (fuelprice * \zeta) =. \left[\left(\frac{\$}{GJ} \times \frac{GJ}{MW^2h}\right)\right] = \left(\frac{\$}{MW^2h}\right)$.

Performing the following multiplications $\alpha * Y_t = \left(\frac{\$}{MWh} \times MW\right) = \left(\frac{\$}{h}\right)$ and $\beta * Y_t^2 = \left(\frac{\$}{MW^2h} \times MW^2\right) = \left(\frac{\$}{h}\right)$, establishes that $FUELCOST_t$, $VOMC_t$ and TVC_t are all measured in terms of $\left(\frac{\$}{h}\right)$.

Equation 7 derives the Short Run Marginal Cost (SRMC) from Equation 6. SRMC units are $/MWh.

Equation 7: Short run marginal cost

$$SRMC = \left(\frac{\partial TVC_t}{\partial Y_t} \right) = \alpha + 2 * \beta * Y_t = \left[\left(\frac{\$}{MWh} \right) + \left(2 \times \frac{\$}{MW^2 h} \times MW \right) \right] = \left(\frac{\$}{MWh} \right),$$

Where

$\alpha = 56.1208$ and $\beta = 0.0175$ for the gas component; and

$\alpha = 1.0208$ and $\beta = 0.0$ for the solar component.

We have assumed that $\gamma = 0$ in the case of the gas component, with this component assumed to be included within the Fixed Operational and Maintenance (FOMC) costs defined below. In the case of the solar component, $fuelprice = 0$ implying that $\gamma = \beta = 0$ and $\alpha = om_v$ with $TVC_t = om_v * Y_t$ and $SRMC = \alpha = om_v$.

Note that Equation 6 directly matches the functional form of equation (5) in Sun and Tesfatsion (2007b, p. 12). For further details on the derivation of variable costs, see Wild, Bell and Foster (2012b, app. A).

3.8.2 Fixed costs

Over the medium to long term, generators need to cover fixed operating costs while also making contributions to debt servicing and producing acceptable returns to shareholders. The convention has been to express the fixed cost 'charges' as a per kilowatt (kW) capacity charge across some period of time, typically a year. Specifically, fixed costs are counted against a generator's installed capacity – generators with zero units do not incur fixed costs. The fixed cost components include Fixed Operation and Maintenance costs (FOMC) and amortised capital cost ($CAPEX_{am}$). In this section, we calculate the capacity factor adjusted total fixed costs per half-hour for the proposed plant shown in Equation 8.

Equation 8: Capacity factor adjusted amortised total fixed costs per half-hour

$$\begin{aligned} Fixed\_Costs\_adj^{hh} &= FOMC\_adj^{hh} + CapCost\_adj^{hh} \\ &= \$1004.21 + \$3624.73 \\ &= \$4,628.94/hh \end{aligned}$$

The numbers expressed in Equation 8 relate to the value of the $FOMC\_adj^{hh}$ component without any adjustment for inflation and which would be applicable to the initial year of operation of the generation plant. Over future years of the plant's operation, the item $FOMC\_adj^{hh}$ *would escalate at the assumed rate of inflation, thereby also inflating the value of* $Fixed\_Costs\_adj^{hh}$ *over these years.* Sections 3.8.2.1and 3.8.2.2 calculate the half-hourly capacity adjusted FOMC and CAPEX, respectively.

3.8.2.1 Annual Fixed Operation and Maintenance Costs

Annual fixed operation and maintenance costs (FOMC) are pro-rated against the installed kilowatt capacity of the generator where the *MW* installed capacity is defined as the maximum installed capacity multiplied by the number of units and then converted to a *kW* basis as shown in Equation 9 where the FOMC units are $(\$/kW/year)$ or $(\$/kWy)$ (Stoft 2002). Equation 9 assumes the generator has total annual FOMC of *$9.53 million* and installed capacity of *30 MW*.

Equation 9: Annual fixed operations and maintenance costs per kW

FOM = $9.53 m / 30 MW = $317.67 /kWy

In order to determine the *$/hh* cost, we determine the 'capacity augmented' *$/y* value using the following formula.

Equation 10: Annual fixed operation and maintenance cost

$$FOMC = 30000kW \times FOM = \left(\frac{30000 \times \$317.67}{y}\right) = \frac{\$9530000}{y}.$$

Then to derive the half-hourly based $\left(\frac{\$}{hh}\right)$ cost, we apply

Equation 11: Fixed operation and maintenance cost per half-hour

$$FOMC^{hh} = FOMC \times \frac{y}{17520hh} = \frac{\$9530000}{y} \times \frac{y}{17520hh} = \frac{\$9530000}{17520hh} = \frac{\$543.95}{hh}.$$

Equation 12 adjusts the half-hourly FOMC in Equation 11 by a calculated whole plant capacity factor of 0.5417.

Equation 12: Capacity factor adjusted fixed operation and maintenance cost per half-hour

$$FOMC\_adj_i^{hh} = \frac{\$543.95}{hh} \times \frac{1}{0.5417} = \frac{\$1004.21}{hh}.$$

This half-hourly dollar figure must be covered during the operational hours of the plant within a representative year. We also assume that $FOMC^{hh}$ is escalated by the rate of inflation over the lifetime of the generation plant.

3.8.2.2 Amortized Capital Costs

The allocation to cover fixed cost associated with the initial capital outlay can also be calculated. Suppose that generator initial capital outlay was *$285.9 million*. Equation 13 expresses the 'overnight' capital cost pro-rated against installed capacity producing a valuation in terms of *$/kW.*

Equation 13: Capital cost per kW

CapCost = $285.9 million / 30,000 kW = 9,529.90/kW

However, the overnight cost of capacity represented in Equation 13 does not correspond to an equivalent *$/kWy* unless we assume that the lifespan of the asset is one year and a discount rate of zero percent (Stoft 2002, p. 35). We need to amortize this cost factor in order to express it in terms of *$/kWy*. Equation 14 calculates the 'amortized' annual capital cost per kW assuming the 40-year lifetime of the proposed plant and a discount rate of 11.93% as the weighted average cost of capital (WACC).

Equation 14: Amortised annual capital cost per kW

$$CapCost^{a} = \frac{(r \times CapCost)}{1-\frac{1}{\left(1+\frac{r}{17520}\right)^{(n\times 17520)}}} = \frac{(0.1193 * 9529.90)}{1-\frac{1}{\left(1+\frac{0.1193}{17520}\right)^{(700800)}}} = \frac{1136.92}{1-\frac{1}{(1.0000063)^{(700800)}}}$$

$$= \frac{1136.92}{1-0.012278} = \frac{1136.92}{0.9877} = \$1146.62 / kWy,$$

where $r = WACC = 0.1193$ and $n = 40$.

Equation 15 converts the amortised annual capital cost per kW in Equation 14 into the amortised annual capital cost per annum.

Equation 15: Amortised annual capital costs

$$CC = 30000kW \times CapCost^{a} = \left(\frac{30000 \times \$1146.62}{y}\right) = \frac{\$34398647.6}{y}.$$

Then to derive the $\left(\frac{\$}{hh}\right)$ cost, we apply

Equation 16: Amortised capital cost per half hour

$$CapCost^{hh} = CC \times \frac{y}{17520hh} = \frac{\$34398647.6}{y} \times \frac{y}{17520hh} = \frac{\$34398647.6}{17520hh} = \frac{\$1963.39}{hh}.$$

To derive the capacity factor adjusted $CapCost\_adj_{i}^{hh}$, we divide Equation 16 by the capacity factor, that is

Equation 17: Capacity factor adjusted amortised capital cost per half-hour

$$CapCost\_adj^{hh} = \frac{\$1963.39}{hh} \times \frac{1}{0.5417} = \frac{\$3624.73}{hh}.$$

3.8.2.3 Indexation for inflation differences

The $FOMC\_adj^{hh}$ cost component is indexed for inflation but $CapCost\_adj^{hh}$ is not because this fixed cost item has been amortised over the assumed lifespan of the generation project. Equation 8 shows the capacity factor adjusted total fixed costs per operational half-hour calculated by adding the $FOMC\_adj^{hh}$ and $CapCost\_adj^{hh}$ to give operational fixed costs $\left(Fixed\_\cos t^{hh}\right)$ of *$4,628.94/hh*. The $CapCost\_adj^{hh}$ component relative to the escalating $FOMC\_adj^{hh}$ component is much larger in magnitude. Therefore, the rate of increases in the capacity factor adjusted total fixed costs per operational half-hour in Equation 8 is significantly less than the assumed rate of inflation.

3.8.3 Power Purchase Agreement Revenue Streams

Equation 18 and Equation 19 show the power purchases agreements (PPA) revenue streams available to the gas and solar component of the proposed plant, respectively. Each attracting an unsubsidised 'black' and subsidised 'green' PPA strike price, respectively.

Equation 18: PPA revenue for the gas component

$$PP\mathrm{Re}v_{GAS} = \sum_{t=1}^{N} PPA\_\mathrm{Pr}ice_{GAS} \times Y_t^{gas}$$

Where

$PPA\_\mathrm{Pr}ice_{GAS}$ = PPA black component (unsubsidised)

Y_t^{gas} = output from the gas component at time *t*

Equation 19: PPA revenue for the solar component

$$PP\mathrm{Re}v_{SOLAR} = \sum_{t=1}^{N} PPA\_\mathrm{Pr}ice_{SOLAR} \times Y_t^{solar}$$

Where

$PPA\_\mathrm{Pr}ice_{SOLAR}$ = PPA green component (including renewable subsidy)

Y_t^{solar} = output from the solar component at time *t*

3.8.4 Half-hourly Operating Cash Flow

The key operating metric is the plant's half-hourly cash flow associated with wholesale market operations, PPA revenue and incurred fixed costs pro-rated to a capacity factor adjusted half-hourly basis that reflects the operational dispatch of the plant according to the dispatch profile outlined in Table 3 and the TYM based solar output. Note that we do not incorporate depreciation costs within this measure.

Equation 20 shows the total half-hourly PPA revenue from both the gas and solar components shown in Equation 18 and Equation 19, respectively.

Equation 20: Half-hourly PPA revenue from both the gas and solar components

$$PPA\_REV_t = PPA\mathrm{Re}v_{GAS,t} + PPA\mathrm{Re}v_{SOLAR,t}.$$

Equation 21 calculates the operating cash flow as the sum of the wholesale market profit (WMP) and PPA revenue (PPA_REV) less operational fixed costs from Equation 3, Equation 20 and Equation 8, respectively.

Equation 21: Half-hourly Operating cash flow (OCF)

$$OCF_t = WMP_t + PPA\_REV_t - Fixed\_Costs\_adj_t^{hh}.$$

Note that the calculation of wholesale market costs and PPA revenue is linked to the output of the gas and solar components of the plant respectively while wholesale market revenue and pro-rated fixed costs are based upon the output and fixed costs of the whole plant.

Of course, if either of these components is not dispatched during the half-hourly dispatch interval, the wholesale market revenue and costs as well as the PPA revenue associated with that component will be zero but the full capacity factor adjusted half-hourly pro-rated fixed cost will be incurred as long as some dispatch of the plant occurs. If the plant is not dispatched, then no wholesale market cash flow, PPA revenue or pro-rated fixed costs will be earned or incurred by the plant.

Equation 22 shows the annual operating cash flow that aggregates the half-hourly operating cash flows in Equation 21 to produce an annual figure.

Equation 22: Annual operating cash flow (AOCF)

$$AOCF = \sum_{t=1}^{N} OCF_t.$$

Collating the projected annual cash flow outcomes for each year over the lifetime of the project enables one to perform NPV analysis to assess the financial feasibility of the project given the initial capital outlay associated with the construction of the generation plant – e.g. its 'overnight' capital cost. Moreover, this analysis can also be used to assess what gas and solar PPA strike prices might be required given the dispatch profile outlined in Table 3 and TMY based yield of the LFR to ensure the financial feasibility of the project. In this context, project feasibility is linked to achieving a positive NPV for the project and is calculated in excel using the formula in Equation 23.

Equation 23: Net Present Value of annual operating Cash flows less CAPEX

$$NPV^{calc} = -Capex + NPV\left(AOCF_1, AOCF_2, ..., AOCF_n\right),$$

where $Capex$ is the overnight capital cost of the project (in $m) and $AOCF_j$ is the projected annual cash flow of the generator in year $'j'$ calculated from Equation 22 for all years over the lifetime of the plant, i.e. $j = 1,...,n,$ where we have assumed that $n = 40$ years.

Note that in the above calculations we have incorporated information contained in RATCH's May 2014 'Assumptions Register' document (RAC 2014) relating to the capital cost of the project (e.g. $Capex$ in $m), FOMC ($m, p.a.). We have also incorporated the latest technical parameters relating to fuel costs (in $/GJ), Variable Operation and Maintenance (VOMC) costs (in $/MWh), auxiliary load (in % terms) as well as heat rate data needed to calculate the SRMC of the hybrid plant according to Equation 7: Short run marginal cost. Additionally, we assumed a WACC of 11.93% and a generation plant lifetime of 40 years.

3.9 Conclusion

In this section, we have operationalised the research questions arising from the literature review in Section 2. We are ready to apply the methodology to calculate the results, which we present in the next section.

4 Results

This chapter presents the results from running the simulations described in the methodology to address the research questions arising from the literature review. Section 2.4.2 discusses the estimation of the expected lower and upper bounds for domestic gas prices to determine a sensitivity of the NEM's wholesale spot prices and plant's revenue to gas prices. Five research questions form the main section headings in this results chapter:

- *What is the expected TMY dispatch of the proposed plant given the plant's dispatch profile for hours of the week and expected TMY yield of the LFR?*
- *What are the half-hourly wholesale spots prices for the plant's lifetime without gas as a bridging technology?*
    - *Assuming a reference gas price of between $5.27/GJ to $7.19/GJ for base-load gas generation (depending upon nodal location;) and*
    - *for peak-load gas generation of between $6.59/GJ to $8.99/GJ; and*
    - *given the plant's dispatch profile*
- *What are the half-hourly wholesale spots prices for the plant's lifetime with gas as a bridging technology?*
    - *Assuming some replacement of coal with gas generation*
- *How sensitive are wholesale spot prices to higher gas prices?*
    - *Assuming high gas prices are between $7.79/GJ to $9.71/GJ for base-load gas generation (depending upon nodal location); and*
    - *for peak-load gas generation of between $9.74/GJ to $12.14/GJ; and*
- *What is the plant's revenue for these reference gas prices?*
- *How sensitive is the plant's revenue to gas as a bridging technology?*
- *How sensitive is the plant's revenue to higher gas prices?*
- *What is the levelised cost of energy for the proposed plant?*

4.1 What is the expected TMY dispatch of the proposed plant given the plant's dispatch profile for hours of the week and expected TMY yield of the LFR?

Table 14 shows the TMMs we selected for the TMY for the years 2007-13 in our previous report (Bell, Wild & Foster 2014b). Table 14 also shows the gross average daily energy of the LFR's TMMs. The hourly yield results from SAM (2014) provide the basis for the calculations in Table 14. We also discuss in our previous report (Bell, Wild & Foster 2014b sec. 7.8) why the yield in Table 14 fails to follow an expected smooth annual cycle.

Table 14: Years for the Typical Meteorological Months and Average daily Energy

Month	TMM's year	Energy (MWh)
Jan	2008	57.5
Feb	2011	64.3
Mar	2008	69.9
Apr	2012	96.7
May	2012	66.6
Jun	2010	64.6
Jul	2008	68.2
Aug	2008	109.0
Sep	2008	125.6
Oct	2007	165.3
Nov	2011	117.9
Dec	2008	116.2
Monthly Ave		93.5

(Source: Bell, Wild & Foster 2014b tbl. 18)

We interpolate hourly LFR yield results from SAM (2014) to provide half-hourly data. Table 15 shows the average daily output from the LFR and gas generators and their combined output based on half-hourly data. There is a monthly average rounding error in Table 15 due to interpolating the hourly results from Table 14. Table 3 shows the proposed plant's dispatch profile by hour of the week.

Table 15: The daily average energy from the LFR, gas and combined plant

Month	LRF (MWh)	Gas (MWh)	Combined (MWh)	Parasitic (MWh)
Jan	57.5	297.6	355.1	5.4
Feb	64.3	276.4	340.7	5.5
Mar	69.9	261.1	331.0	5.4
Apr	96.7	254.6	351.3	5.7
May	66.6	294.3	360.9	5.1
Jun	64.6	293.1	357.6	5.1
Jul	68.2	289.7	358.0	5.0
Aug	109.0	239.2	348.2	5.4
Sep	125.6	263.6	389.2	5.9
Oct	165.3	228.8	394.1	6.6
Nov	117.9	248.5	366.4	6.1
Dec	116.2	247.6	363.8	6.6
Monthly Ave	93.6	266.1	359.8	5.7

When forming a TMY from TMMs, the proportions of the days of the week become unbalanced within the TMY. This effect could bias calculations based on projections using the TMY. For instance, RATCH only intends running the proposed plant's gas generator during the weekdays. Consequently, if the TMY has a bias toward weekdays rather than weekend days, the analysis in the following research questions will over report gas usage.

Table 16 shows the TMY's number of days by day of the week and by month. The average number of a particular day of the week for a year is 52 after rounding 52.14285714 (=365/7).

Table 16 shows a yearly bias of over reporting Mondays, Tuesdays and Wednesdays by one, four and three days respectively and underreporting Thursdays, Fridays, Saturdays and Sundays by one, three, two and one day respectively. The more important issue for the plant's gas consumption is that weekdays are over reported 3 days per year and weekend underreported 3 days. Therefore, the projections based on this distribution may over report the plant's gas consumption by 0.9%.

Table 16: TMY's monthly distribution of the days of the week

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Bias
Sun	4	4	5	5	4	4	4	5	4	4	4	4	51	-1
Mon	4	4	5	5	4	4	4	4	5	5	4	5	53	1
Tue	5	4	4	4	5	5	5	4	5	5	5	5	56	4
Wed	5	4	4	4	5	5	5	4	4	5	5	5	55	3
Thu	5	4	4	4	5	4	5	4	4	4	4	4	51	-1
Fri	4	4	4	4	4	4	4	5	4	4	4	4	49	-3
Sat	4	4	5	4	4	4	4	5	4	4	4	4	50	-2
Total	31	28	31	30	31	30	31	31	30	31	30	31	365	

Table 17 shows the annual GWh production levels and annual capacity factors of the solar, gas and combined (e.g. whole) plant for the demand profile in Table 3. The GWh annual production level for the solar component of the hybrid plant of 34.17 GWh shown in Table 17 is significantly less than the latest annual production figure for this component assumed by RATCH, which is 55.76 GWh. In contrast, the annual GWh production level for the gas component of the hybrid plant in Table 17 is 97.14 GWh. This result, in turn, is significantly more than the equivalent latest annual production level assumed by RATCH of 75.33 GWh. Contributing to the divergence in results is the disparity between the DNI readings from Allen (2013) terrestrially based instruments and those DNI values the BoM (2013) calculates from satellite imagery. Our study uses Allen's (2013) terrestrially measured DNI data and the other studies use satellite derived DNI data. In our previous report (Bell, Wild & Foster 2014b), we found a ratio of 0.767 between the DNI data from Allen (2013) and from BoM (2013). This disparity in DNI would contribute to the difference between the yields. This DNI disparity needs investigating. In our previous report, we discuss using the Rockhampton weather station one-minute solar data from BoM (2012) in a comparative study to investigate yield based on satellite and terrestrial based DNI data.

Table 17: Annual GWh Production and Capacity Factors associated with the given dispatch profile

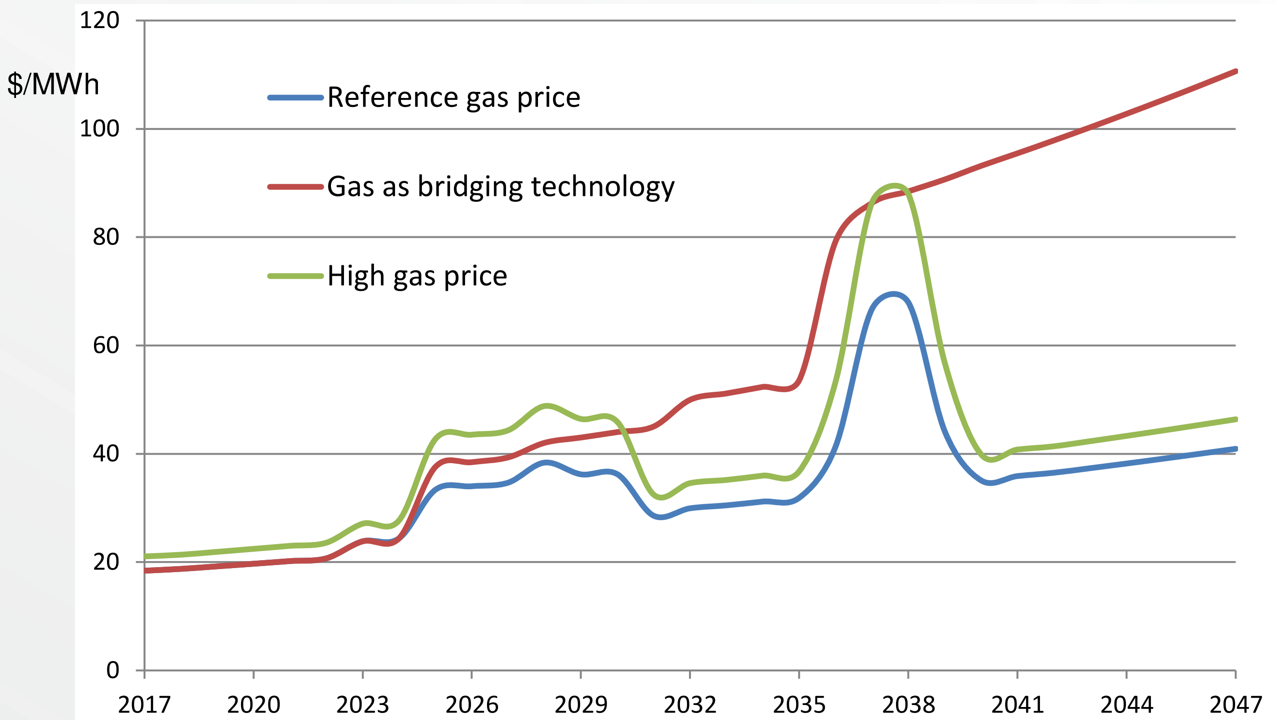
Estimated Capacity factor	Solar	Gas	Combined
Annual production GWh	34.17	97.14	131.32
Annual production MWh	34,173	97,143	131,316
Max Capacity	30	30	30
Number of hours in a year	8760	8760	8760
Total Potential Annual production	262,800	262,800	262,800
Annual Capacity factor	0.1300	0.3696	0.4997

4.2 What are the half-hourly wholesale spots prices for the plant's lifetime without gas as a bridging technology?

Figure 13 shows the annual average wholesale spot prices for the proposed plant calculated by the ANEM model described in Sections 3.2, 3.3 and 3.4 for 3 scenarios:

- Reference gas prices
- Gas as a bridging technology
- High gas prices

Figure 13: Annual average wholesale spot prices for three scenarios on Collinsville's node



This section discusses the "reference gas price" research question and the following two sections discuss "gas as a bridging technology" and "high gas price" research questions.

The reference gas price shows a number of distinct changes in electricity prices and a gradual increase. The 2.5% inflation rate built into the ANEM model can explain the gradual increase in wholesale spot market prices. The shutdown or start-up of plant can explain the distinct changes. Section 5.2 provides detailed reasons for the shape of the "reference gas price" line in Figure 13.

4.3 What are the half-hourly wholesale spots prices for the plant's lifetime with gas as a bridging technology?

Figure 13 shows the annual average spot market prices for "gas as a bridging technology" where CCGT generators gradually replace coal-fired generators as they retire. This replacement process only starts in 2025. Hence, the "reference gas price" and "gas as a bridging technology" lines are coincident until 2024 before they diverge in 2025. The replacement process is cumulative producing a permanent rise in electricity prices. The "gas as a bridging technology" option induces an average wholesale electricity spot market price increase of $33.33/MWh over the period 2025-2047 or 86% above the "reference gas price" scenario. Section 5.3 provides detailed reasons for the shape of the “gas as a bridging technology” line in Figure 13.

4.4 How sensitive are wholesale spot prices to higher gas prices?

The sensitivity of wholesale market spot prices to a high gas price is an average increase of $6.76/MWh over the “reference gas price” for the period 2014-47 or a percentage increase of 20%. Section 5.4 provides detailed reasons for the shape of the “high gas price” line relative to the “reference gas price” line in Figure 13.

4.5 What is the plant’s revenue for the reference gas prices?

Table 18 shows the proposed plants lifetime revenue NPV based on the year 2017 with a discount factor of 0.11 and assuming the dispatch profile in Table 3. The Short Run Marginal Cost (SRMC) of the plant’s gas component was calculated to be $56.1208/MWh in 2014-dollar terms, and Figure 13 shows that the average wholesale spot price is seldom above this SRMC value. This calls into question the short-run profitability of the gas component. Given the dispatch profile in Table 3, the total variable cost of the gas component’s NPV based on the year 2017 with a discount factor of 0.11 and indexing the $56.1208/MWh for inflation at 2.5% per annum is $68,266,743. Section 5.10 discusses using a different gas dispatch profiles to improve the profitability of the plant.

Table 18: NPV Revenue for the three scenarios using 0.11 discount factor and 2017 base year

	Reference gas price	Gas as Bridging technology	High gas price
LFR	$8,981,638	$12,890,293	$11,311,368
Gas	$27,460,708	$39,543,077	$35,392,121
Total Revenue	$36,442,346	$52,433,370	$46,703,488
LFR Parasitic load	$499,341	$686,704	$609,424

The LFR revenue in Table 18 excludes any subsidies.

4.6 How sensitive is the plant’s revenue to gas as bridging technology?

Table 19 shows the sensitivity of the plant’s “reference gas price” revenue to two scenarios “gas as a bridging technology” and “high gas price”. The “gas as a bridging technology” scenario relative to the “reference gas price” shows an increase in revenue by a factor of 1.44 for the LFR, gas and total revenues.

Table 19: Sensitivity of the plant's revenue to alternative scenarios

	Reference gas price	Gas as Bridging technology	High gas price
LFR	1.00	1.44	1.26
Gas	1.00	1.44	1.29
Total Revenue	1.00	1.44	1.28
LFR Parasitic load	1.00	1.38	1.22

4.7 How sensitive is the plant’s revenue to higher gas prices?

Table 19 shows that the sensitivity of the plant’s “reference gas price” revenue to “high gas price” is an increase in revenue by a factor of 1.26, 1.29 and 1.28 for the LFR, gas and total revenues, respectively.

4.8 What is the Levelised Cost of Energy?

This section calculates and compares the Levelised Cost of Energy (LCOE) under two scenarios: using the LFR yield forecasts in our previous report (Bell, Wild & Foster 2014b) with a capacity factor of 0.13 and inflating this LFR yield to match the capacity factor of 0.2122 reported in RAC (2014).

4.8.1 LCOE based on the yield forecast report

This section presents the results from applying the methodology described in Section 3.8.

We calculated capacity factors of 0.5417, 0.4538 and 0.2489 by counting the number of half hours in the TMY during which production were greater than zero for the combined plant, the gas and the solar components, respectively and dividing by 17520 half-hours, that is, the total number of half hours in the TMY. Section 3.8 uses these capacity factors to calculate the adjusted half-hourly $CapCost\_adj_i^{hh}$ and $FOMC\_adj_i^{hh}$.

Table 20 compares the capacity factors between RATCH and those listed in Table 17 and those calculated in the previous paragraph. Note that these numbers exceed the capacity factors of 0.4997, 0.3696 and 0.1300 outlined in Table 17 that were based on the aggregate GWh production levels of all three components determined from the dispatch profile in Table 3 and the solar yield of the LFR associated with the TMY. Moreover, assuming the expected GWh production levels cited in RAC (2014) produces equivalent capacity factors of 0.4988, 0.2866 and 0.2122 for whole plant, gas and solar components. Note that these latter values are below the dispatch based figures used in the analysis for whole plant (of 0.5417) and gas (0.4538) and for the solar component (of 0.2489). Table 20 lists these three sets of results.

Table 20: Comparing capacity factors between this report and RAC (2014)

	combined	gas	solar
Table 17 in section 4.1	0.4997	0.3696	0.1300
This section	0.5417	0.4538	0.2489
RAC (2014)	0.4988	0.2866	0.2122

For the ‘Reference gas price’ scenario, the annual wholesale market profits were only secured in years 2037-2038. In all other years, wholesale market losses were experienced under this scenario. The ‘High gas price’ scenario secured annual wholesale market profitability over the years 2025 to 2030 and 2036 to 2039. In the case of the ‘Gas as bridging technology’ scenario, annual wholesale market profits were experienced over years 2028 to 2047.

The wide experience of wholesale market losses would predominately be attributable to the dispatch of the gas component of the hybrid plant during dispatch intervals where the spot price was below the plant’s SRMC. This would be the converse of the situation outlined in the last rows of Table 28, Table 31 and Table 34 that shows the percentage of time in each year whereby spot prices exceeded the SRMC of the gas component, pointing to profitability. In Sections 5.5, 5.6 and 5.7 temporary increases in the percentage exceedance rates were observed for the ‘Reference gas price’ and ‘High gas price’ scenarios in Table 28 and Table 34 while a permanent increase was observed in the case of the ’Gas as bridging technology’ scenario (in Table 31). One explanation offered for this behaviour was temporary increases in average spot prices associated with the withdrawal of capacity from Gladstone, Tarong and Callide B power stations in the refurbishment scenarios, and the replacement of Gladstone, Tarong and Callide B power stations with more costly CCGT alternatives in the case of the CCGT replacement scenario. To gauge the nature of the uplift in spot prices, Table 21 lists the volume weighted average prices for selected years for all three scenarios identified above. It should be noted that the volume weighting is done using the demand at node 3 as the volume measure and the nodal spot price as the price measure.

Table 21: Volume weighted average prices for node 3 for selected years and scenario

Scenario	2030	2035	2036	2037	2038	2039	2040
Reference gas price	38.30	32.89	43.22	71.99	73.22	46.10	36.13
High gas price	49.14	38.29	56.54	93.50	95.11	60.12	41.44
Gas as bridging technology	45.61	55.51	81.17	88.03	90.22	92.46	95.01

In Table 21, the results for year 2030 are listed because this year was the last year associated with the refurbishment of Gladstone power station. It is clear that this produced a slight up-lift in average prices in the case of the ‘Reference gas price’ and ‘High gas price’ scenarios relative to the average prices recorded in year 2035. In the case of the ‘Gas as bridging technology” scenario, the uplift in spot price is permanently locked in as seen with the continued rise in the average price in 2035 over year 2030. The noticeable increase in average prices in years 2037-2038, in the case of the first two scenarios, and from 2036 onwards in the case of the third scenario, maps out an approximate price range for average price levels consistent with strong wholesale market profitability of between \$72.0/MWh and \$95.1/MWh, in volume weighted terms. However, given the wholesale market profitability of the two latter scenarios in 2030, average prices in the range of \$45.6/MWh to \$49.1/MWh in volume-weighted terms were clearly sufficient to secure wholesale market profitability in 2030, albeit, much less strongly than in 2037-2038. Clearly, the average prices beyond 2038 remain at these levels in the case of the third (‘Gas as bridging technology‘) scenario ensuring continued wholesale market profitability. However, the average prices fall back to levels existing prior to 2030 in the first two (‘Reference gas price’ and ‘High gas price’), scenarios, producing a move back into wholesale market losses.

Thus, in the case of all three scenarios considered, overall profitability and financial feasibility of the project hinges crucially upon the ability to get PPA strike prices that would earn enough revenue to offset sustained wholesale market losses as well as adequately covering the fixed costs liable to be paid over the lifetime of the project. This aspect is investigated in Table 22, which documents the NPV of the project for various PPA ‘gas’ and ‘solar’ strike prices. Table 22 traces out the NPV values for a general configuration of gas and solar PPA strike prices applicable to output from the gas and solar components of the hybrid plant, respectively. These strike prices are listed in columns 1 and 2.

Table 22: NPV Analysis for Various PPA Strike Prices Combinations by Scenario

PPA		NPV		
Gas ($/MWh)	Solar ($/MWh)	Reference gas price ($m)	High gas price ($m)	Gas as a bridging technology ($m)
100	160	-$387.7	-$367.5	-$365.6
120	180	-$331.6	-$311.4	-$309.5
150	210	-$247.5	-$227.3	-$225.4
180	240	-$163.4	-$143.2	-$141.3
200	260	-$107.4	-$87.1	-$85.3
230	290	-$23.3	-$3.0	-$1.2
230	300	-$16.0	$4.3	$6.1
240	300	$4.7	$25.0	$26.9
250	310	$32.7	$53.0	$54.9

It is evident from Table 22 that PPA prices in the range of $240/MWh and $300/MWh would be needed to ensure financial feasibility of the project. This outcome depends crucially on the dispatch profile listed in Table 3, the TMY yield of the LFR, cost and other technical assumptions employed in the modelling and prices obtained from simulations of the ANEM market under all three scenarios considered. Note that in Table 22, the cells in columns 3 to 5 consistent with obtaining a positive NPV results are shaded in light grey shading.

Given the capacity factor of 0.4538 used in this analysis for the gas component of the hybrid plant in this section, this produces a levelised cost of energy for this component of around $222/MWh. Note that this is below the comparable levelised costs associated with the other two capacity factors mentioned above – namely of $316/MWh for a capacity factor of 0.2866 and $259/MWh for a capacity factor of 0.3696 listed in Table 17. In Table 23, we assume that the PPA strike price for the gas component is set to its levelised cost of $222/MWh and now investigate what PPA strike price would be needed for the solar component to ensure financial viability of the project.

Table 23 also documents the NPV of the project for a fixed PPA ‘gas’ strike price and various ‘solar’ strike prices. The results in Table 23 indicate that the strike price depends upon the scenario adopted. For all three scenarios, a PPA ‘solar’ price of around $350/MWh is needed to ensure financial feasibility under all three scenarios. If attention is restricted to the ‘High gas price’ scenario, a PPA ‘solar’ strike price of around $320/MWh would secure financial viability of the project under this particular scenario. If we focus upon the ‘Gas as bridging technology‘ scenario, a PPA ‘solar’ strike price of around $320/MWh would also secure financial viability.

Table 23: Sweet spot analysis assuming PPA strike price for gas equals levelised cost of gas component

PPA		NPV		
Gas ($/MWh)	Solar ($/MWh)	Reference gas price ($m)	High gas price ($m)	Gas as a bridging technology ($m)
222	310	-$25.3	-$5.0	-$3.2
222	320	-$18.0	$2.3	$4.1
222	330	-$10.7	$9.6	$11.4
222	340	-$3.4	$16.8	$18.7
222	350	$3.9	$24.1	$26.0
222	360	$11.2	$31.4	$33.3

From the NPV analysis reported in Table 23, the project would be feasible with a PPA strike price for gas of $222/MWh and PPA strike prices set to the levelised costs of the solar component associated with the two other capacity factor values listed in Table 20. For example, assuming a capacity factor for the solar component of 0.2122 would produce a levelised cost of approximately $402/MWh for the solar component, well above the limits listed in Table 23. Similarly, if we use the much lower value in Table 17 (of 0.1300), this would produce a levelised cost of energy for the solar component of the hybrid plant of $656/MWh, a significant rise on the $402/MWh value mentioned immediately above. Note, however, that for a capacity factor for the solar component of 0.2489 listed in Table 20, this produces a levelised cost of $343/MWh for the solar component. However, according to the results listed in Table 23, the project would be marginal under the ‘Reference gas price’ scenario although it would be feasible under both the ‘High gas price’ and ‘Gas as a bridging technology’ scenarios, assuming a PPA gas strike price of $222/MWh.

4.8.2 LCOE based on an inflated LFR yield

In this section, we construct a LFR profile with a capacity factor of 21.2% by inflating the LFR profiles in the previous section that has a capacity factor of 13.0%. This helps assess how sensitive the PPA strike price is to the LFR capacity factor. This upward scaling employs the patterns of the original LFR profile determined for the project but re-maps upwards the output by a constant amount to achieve the desired higher annual capacity factor outcome. As such, periods where no solar output occurred continue to hold for the modified LFR profile and we have set a maximum MW capacity limit for the LFR plant to 36.06 MW, which was the maximum half-hourly value recorded in relation to the original LFR profile. To achieve a capacity factor of 21.2 per cent, it was necessary to scale the output of the original LFR profile by a factor of 1.995. In aggregate production terms, with this scaling, the annual capacity factors of the solar, gas ‘top-up’ components and whole of plant were 0.2120, 0.3278 and 0.5398, respectively.

We reproduce the results listed in Table 22 in Table 24 for the new LFR solar profile to assess how the PPA strike prices might be changed with expanded output from the LFR plant, assuming that the wholesale spot prices from ANEM model runs, which underpin the results in Table 22 continue to hold.

Table 24: Inflated yield NPV Analysis for Various PPA Strike Prices Combinations by Scenario

PPA		NPV		
Gas ($/MWh)	Solar ($/MWh)	Reference gas price ($m)	High gas price ($m)	Gas as a bridging technology ($m)
100	160	-$321.1	-$300.1	-$297.3
120	180	-$260.5	-$239.5	-$236.8
150	210	-$169.6	-$148.7	-$145.9
180	240	-$78.8	-$57.8	-$55.1
200	260	-$18.2	$2.7	$5.5
200	275	-$0.4	$20.6	$23.4
205	270	$2.9	$23.8	$26.6
205	280	$14.8	$35.7	$38.5

A comparison of Table 24 and Table 22 indicates that the PPA strike prices required to achieve financial viability have now fallen from $240/MWh and $300/MWh under the original LFR profile to a range between $200/MWh and $205/MWh for the gas component and between $260/MWh and $270/MWh for the solar component. This amounts to reductions of $35/MWh to $40/MWh for the gas component and between $30/MWh and $40/MWh for the solar component. The financial viable scenarios are shaded light grey in Table 24.

Finally, in the previous subsection we identified that average prices in the range of $45.6/MWh to $49.1/MWh seemed to be necessary to achieve overall wholesale market profitability, whilst, higher average prices of $72.0/MWh to $95.1/MWh seemed to be necessary to ensure strong wholesale market profitability. In the latter context, this is linked to the ability of the higher average prices to cover the more expensive SRMC of the gas component of the hybrid plant. However, for financial viability, it is also necessary to earn enough revenue from both PPA and wholesale market revenue streams to cover fixed costs, including the amortised capital cost of the plant. In the analysis above, we have varied the PPA strike prices in order to determine financial viability given the outcomes from ANEM wholesale market simulations. However, in RAC (2014), PPA strike prices for output from the gas and solar components of the hybrid plant of $120/MWh and $180/MWh, respectively, were assumed.

A question remains about what average wholesale prices would be needed, given the assumed technical parameters, PPA strike prices and solar and gas output profiles, to ensure financial viability of the hybrid plant under the current assumed operating regime outlined in Table 3. To address this issue, NPV analysis was performed assuming the GWh production levels for the gas and LFR components of the hybrid plant with escalation of variable and fixed operational costs and PPA revenue streams according to the inflation escalation rate adopted more generally in the modelling. Recall that the gas and solar PPA strike prices were assumed to be $120/MWh and $180/MWh, respectively. Moreover, wholesale market revenue is calculated by simply multiplying the annual GWh production totals of the whole plant by an assumed average price and then escalating this over the lifetime of the plant on a year-on-year basis at the assumed inflation escalation rate. Thus, this analysis is quite general and aggregated in character and we lose the spot price impacts associated with the nuisances of the three different gas price scenarios incorporated in the ANEM modelling. In Table 25 and Table 26 below, the average prices considered are listed in column 1 while the NPV results are listed in column 2. A positive NPV shaded light grey indicates the financial viability of the project.

The results for the original LFR profile are documented in Table 25 and show that, given the assumed PPA strike prices, an average price of at least $145/MWh is needed to secure a positive NPV value and financial viability of the project.

Table 25: Original yield NPV Analysis for Various Average Price Levels

Price ($/MWh)	NPV ($m)
30	-321.1
50	-265.0
70	-208.9
90	-152.9
110	-96.8
130	-40.7
140	-12.7
145	1.3
150	15.3

The results for the inflated LFR profile associated with an annual capacity factor of 21.2 per cent are documented in Table 26. Note that under this inflated LFR profile, the aggregate GWh production levels associated with the gas and solar components are 86.1 and 55.7 GWh, respectively. We also use the whole of plant capacity factor of 0.5398 associated with the modified LFR profile mentioned above to calculate values of $3,637.14 and $1,007.65 for $CapCost\_adj^{hh}$ and $FOMC\_adj^{hh}$ respectively, (see Equation 6, Equation 12 and Equation 17). The results in Table 26 indicate that an average price of $112/MWh or higher would be needed to secure financial viability, given the assumed PPA strike prices

Table 26: Inflated yield NPV Analysis for Various Average Price Levels

Price ($/MWh)	NPV ($m)
30	-248.2
50	-187.6
70	-127.0
90	-66.5
100	-36.2
110	-5.9
112	0.15
120	24.4
140	84.9

Comparison of the results in Table 25 and Table 26 indicate that the impact of greater output from the LFR component is to reduce the average price needed to ensure financial viability from $145/MWh to $112/MWh, an average price reduction of $33/MWh.

To gauge how the average price requirements identified in Table 25 and Table 26 compare with average prices arising in the NEM, Table 27 contains a list of volume-weighted average prices, state demand and the percentage of time that half-hourly spot prices equal or exceed the $112/MWh and $145/MWh limits identified in Table 25 and Table 26, respectively. Note that the price and demand concept employed in the volume-weighted average price calculation are the half hourly price and demand data available in AEMO (2014b) for the 'QLD1' (i.e. Queensland) market for years 2010, 2011, 2012, 2013 and up to the end of October 2014. Note further that the prices have been adjusted to more closely reflect North Queensland prices by multiplying the state half-hourly prices by the Marginal Loss factor of 1.0307 assumed in RAC (2014) for the 2015-2016 time interval.

Table 27: Price and Demand trends in Queensland 2010-14

	2010	2011	2012	2013	2014*
Weighted average price ($/MWh)	28.92	39.18	45.38	73.99	50.50
Demand (GWh)	52,324	51,107	51,181	49,964	N.A.
% >= $112/MWh	0.27	0.92	1.22	4.13	0.82
% >= $145/MWh	0.19	0.71	0.85	2.81	0.57

From Table 27, year-on-year volume-weighted average prices have tended to climb in magnitude from $28.92/MWh to $73.99/MWh before falling somewhat in 2014 to $50.50/MWh. The sizable increase in 2013 and 2014 relative to earlier years would reflect, in part, the carbon price introduction in July 2012 and subsequent repealed in July 2014. Furthermore, with the removal of the carbon price in July 2014, average prices are likely to trend lower for the remainder of 2014 relative to the average prices levels associated with 2014 and 2013, in particular, in Table 27. Against this backdrop, total demand also clearly declined in 2011 relative to 2010 and then increased marginally in 2012 before falling more significantly in 2013. Thus, increases in demand were not the driving force behind the observed increase in volume-weighted average prices in 2013 as seen in Table 27.

Examination of the last two rows of Table 27 contain the percentage of time that the half-hourly state prices equal or exceed $112/MWh and $145/MWh, the average price limits associated with financial viability of the project for the 'modified' and 'original' TMY LFR output profiles. Clearly, in 2010 and 2011, the percentage results indicate that the half-hourly state prices equalled or exceeded these two limits less than one per cent of the time during these two years. The percentage increased slightly in 2012 to between 0.8 and 1.2 per cent before increasing further in 2013 to between 2.8 and 4.1 per cent of the time in 2013. This increase, once again, occurs over the same period of time when the carbon price was operating, and mirrors qualitatively, the observed increase in volume-weighted average prices over this same period. Given the reduction in annual demand in 2013, these two outcomes most probably reflect increased volatility and uncertainty over the bidding strategy adopted by market participants during this time, together with some permanent and temporary withdrawal of capacity associated with the closure or temporary mothballing of some coal-fired generation plant. It is notable that the 'exceedance' results in the last two rows of Table 27 for 2014 are less than one per cent and more closely match the results for years 2010 and 2011.

More generally, it is clear that the volume-weighted average prices are well below the $112/MWh and $145/MWh limits established in Table 25 and Table 26 for financial viability of the project given the assumed PPA strike prices in RAC (2014). Moreover, the observed spot prices over 2010-2014 do not exceed these price limits very often. Thus, financial viability of the project would most likely require higher PPA strike prices than assumed in RAC (2014) to promote the required price uplift than is likely to be forthcoming from wholesale market operations alone, especially under current conditions of reduced demand and oversupply of generation capacity.

5 Discussion

This discussion section provides a wider context to the results presented in Section 4. Sections 5.2 to 5.4 provide reasons for the wholesale spot prices for the lifetime of the proposed plant, that is, 2014-47. Figure 13 shows these prices. Sections 5.5 to 5.8 analyse how often the wholesale spot price exceeds the gas plant's Short Run Marginal Cost (SRMC). This analysis helps to evaluate the suitability of the proposed dispatch profile in Table 3 to maximise the short-run profit for the gas plant. We analyse the exceedance by hour, by month and by day of the week, finding some months provide major losses for the gas plant when using the proposed profile. Therefore, in Section 5.10, we discuss an alternative approach to the proposed dispatch profile.

The research questions form the main section headings in this discussion chapter with two additional sections for the comparative analysis of the three scenarios and a discussion of an alternative approach to the proposed profile.

5.1 What is the expected dispatch of the proposed plant's gas component given the plant's dispatch profile and expected LFR yield?

Section 4.1 presents the monthly LFR yield and the gas generator top-up to maintain the dispatch profile in Table 3. However, Sections 5.5 to 5.8 scrutinise this profile with a view to improving on the proposed profile. Section 5.10 suggests an alternative profile.

5.2 What are the half-hourly wholesale spots prices for the plant's lifetime without gas as a bridging technology?

We provide reasons for the shape of the "reference gas price" scenario in Figure 13.

The first point to note in Figure 13 and across all three scenarios is that there is no noticeable reduction in average prices at node 3 associated with a merit order effect attributable to the increased penetration of wind generation in the years 2018 and 2023, perhaps except for a very slight 'wobble' in 2024. This outcome is consistent with what we would expect given the very considerable distance between node 3 and the nearest node containing operational wind generation considered in the modelling, which is the Canberra node (node 25) in New South Wales.

In Figure 13, in the case of the reference gas price and coal refurbishment scenario, we see two temporary increases in average spot prices, occurring between 2025 and 2030 and between 2036 and 2039, with a particularly noticeable increase between 2037 and 2038. These temporary increases in average spot prices at node 3 reflect the temporary withdrawal of capacity associated with the refurbishment of Gladstone power station over the years 2025-30 and of Tarong power station over the years 2036-39, together with the refurbishment of Callide B power station over the years 2037-38.

Recall that the refurbishment programme involves the temporary closure of one unit of each of these power stations over these intervals: one unit (280 MW) of Gladstone power station over 2025-30; one unit of Tarong power station (350 MW) over 2036-39; one unit of Callide B (350 MW) over 2037-38. Importantly, for years 2037 and 2038, the combined Tarong/Callide B capacity withdrawals amounts to 700 MW during each of these particular years while the Tarong power station capacity withdrawals amount to capacity withdrawals of 350 MW during years 2036 and 2039. It is evident that the average price rises identified in Figure 13 are closely related to these periods of temporary capacity withdrawal. More specifically, the largest temporary spikes in average prices at node 3 also coincide with the largest capacity withdrawal linked to the withdrawal of one unit from both Tarong and Callide B power stations. The magnitude of the average price increase reflects two particular factors. The first is the size of the capacity withdrawal occurring over the years 2037 and 2038 of 700 MW. Second, the location of Callide B, in particular, is quite close in proximity to node 3, being in the neighbouring node Central West Queensland (node 4). Thus, it is likely, given both the size and location of the two power stations experiencing capacity withdrawals over the years 2037 and 2038 that the increased dispatch of the more expensive gas or hydro generation would eventuate to compensate for the loss of this withdrawn capacity. This would produce higher spot electricity prices in years 2037 and 2038 relative to other years when this withdrawn capacity was available to meet demand.

Apart from the temporary increases in average spot prices associated with temporary withdrawal of capacity for refurbishment purposes, in the other years, average spot prices at node 3 tend to increase with the assumed rate of inflation of 2.5% per annum. As such, the price rises are clearly of a temporary nature as can be discerned from Figure 13.

5.3 What are the half-hourly wholesale spots prices for the plant's lifetime with gas as a bridging technology?

We provide detailed reasons for the shape of the "gas as a bridging technology" line in Figure 13. This is the scenario where CCGT replaces coal-fired generators as they retire.

The increase in average nodal prices relates to the complete replacement of coal-fired plant at the start dates of the refurbishment programme – namely, 2025 for Gladstone power station, 2036 for Tarong power station and 2037 for Callide B power station. Note from inspection of Figure 13 that the initial increase in average nodal price in 2025 falls between the price increases associated with the reference and high gas price scenarios with coal-plant refurbishment scenarios. The reason the prices are lower than those obtained from the high gas price scenario is that gas plant has a higher marginal cost structure under this latter scenario than under the gas as a bridging technology scenario. To the extent that gas plant is the marginal price-setting generator under both scenarios, then the higher marginal cost structure under the high gas price, coal-plant refurbishment scenario will produce higher spot prices under nodal pricing. A key difference, however, is that Gladstone is now permanently replaced with a CCGT plant of roughly equivalent MW capacity but with a significantly higher SRMC that permanently flows through into higher average spot prices post 2030. This situation can be contrast with the other two coal refurbishment scenarios, which revert to pre-2025 average price levels following the refurbishment of Gladstone power station. That is, the increase in the average spot price now becomes permanent and not temporary as in the case of the coal refurbishment scenarios outlined in Figure 13.

The increase in average nodal price observed during years 2036 and 2037 is higher than in the coal-refurbishment scenario, particularly in 2036, although marginally below the average price level associated with the high gas price scenario in 2037. This occurs because we assumed that the complete power stations at Tarong in 2036 and Callide B in 2037 were replaced by CCGT plant of similar capacity and did not involve the phased-in commissioning of successive units over the periods 2036-39 and 2037-38, respectively, as in the case of the coal-refurbishment scenario. The permanency of the replacements at these particular years are seen by the sustained and sharp rise in average nodal price in Figure 13 over the years 2036-37 followed by increases at broadly the assumed rate of inflation of 2.5% per annum after the replacement has occurred. Thus, the replacement process is cumulative producing a sustained permanent rise in electricity prices.

The “gas as a bridging technology” option induces an average wholesale electricity spot market prices increase of $35.32/MWh over the period 2025-2047 or 105%. The rapid rise in electricity prices from 2035 onwards might seem to produces a compelling reason to avoid “gas as a bridging technology” and move directly to alternative sources of electricity generation. However, currently these alternative sources of generation would still need significant additional subsidy support possibly via an expanded RET target and significantly higher LGC prices than currently exist to ensure that the projects are also financially viable. Moreover, the use of a carbon pricing mechanism to promote fuel switching from coal to gas would also lead to similar if not higher average spot price levels than were observed in Figure 13 in relation to the “gas as a bridging technology” scenario. Moreover, these other technologies might not be able to be easily or reliably implemented at an appropriate scale that would significantly replace coal generation plant.

5.4 How sensitive are wholesale spot prices to higher gas prices?

We provide detailed reasons for the shape of the “high gas price” scenario relative to the “reference gas price” scenario in Figure 13.

The trends identified in Section 5.2 in relation to the reference gas price/coal plant refurbishment scenario also continue to hold for the current case involving the high gas price/coal plant refurbishment scenario. Assessment of Figure 13 clearly shows that the average price paths of both of these scenarios closely follow each other in qualitative terms. The ‘uplift’ in the trajectory of the high gas price scenario above the trajectory associated with the reference gas price scenario can be attributed to the lift in variable costs and spot electricity prices associated with the higher gas prices that are prevalent in the higher gas price scenario when compared with the reference gas price scenario.

As such, the key conclusions once again is that noticeable increases in average spot prices at node 3 are temporary in nature and are associated with the temporary withdrawals of capacity associated with the refurbishment of Gladstone, Tarong and Callide B power stations discussed in Section 5.2. The higher gas prices ensure that the average prices are higher than in the case of the reference gas price scenario addressed in Section 5.2. Finally, apart from the temporary increases discussed above, averages prices in other years tend to escalate at their assumed rate of inflation of 2.5% per annum over the years 2014-47.

5.5 What is the plant's revenue for the reference gas prices?

In Section 4.5, we find that the total variable costs of the gas component of the proposed plant exceed its revenue given the proposed dispatch profile in Table 3. In this section, we investigate wholesale spot prices for the years 2017-47 to find a more profitable dispatch profile for the plant given the "reference gas price" scenario. Table 28 shows the day of the week count of the number of half hours that the wholesale spot prices exceed the SRMC of the gas plant for the reference prices gas scenario. The percentage number of exceedances indicates that operating the plant Monday through Friday is the most profitable period to operate.

Table 28: By day of the week - count of half-hourly wholesale spot price exceedance of short run marginal cost for reference gas price

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Sunday	24	24	24	24	24	24	24	24	47	47	47	49	47	47	24	24	24
Monday	177	177	177	177	177	177	173	173	305	305	305	343	310	301	175	187	183
Tuesday	158	152	152	152	152	152	148	148	319	319	319	352	324	305	152	189	181
Wednesday	139	138	137	137	137	137	135	135	291	291	291	334	305	269	138	162	151
Thursday	143	141	141	141	141	141	135	135	270	270	270	298	278	251	138	159	157
Friday	85	84	84	84	84	84	83	83	197	197	197	223	208	187	84	96	94
Saturday	27	27	27	27	27	27	27	27	53	53	53	59	54	51	27	27	27
Total	753	743	742	742	742	742	725	725	1,482	1,482	1,482	1,658	1,526	1,411	738	844	817
Percent	4%	4%	4%	4%	4%	4%	4%	4%	8%	8%	8%	9%	9%	8%	4%	5%	5%

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Total	%
Sunday	24	24	49	116	116	49	24	24	24	24	24	24	24	24	1,118	3%
Monday	183	183	366	681	681	366	177	177	173	173	173	173	173	173	7,674	22%
Tuesday	181	181	363	675	675	363	154	154	150	150	150	150	150	150	7,320	21%
Wednesday	151	151	355	676	676	355	139	139	136	136	136	136	136	136	6,785	19%
Thursday	157	157	347	643	643	347	141	141	136	136	136	136	136	136	6,601	19%
Friday	94	94	252	491	491	252	85	85	83	83	83	83	83	83	4,496	13%
Saturday	27	27	56	112	112	56	27	27	27	27	27	27	27	27	1,226	3%
Total	817	817	1,788	3,394	3,394	1,788	747	747	729	729	729	729	729	729	35,220	100%
Percent	5%	5%	10%	19%	19%	10%	4%	4%	4%	4%	4%	4%	4%	4%	6%	

The final row of the table expresses the number of exceedances as a percentage of the total number of half hours in each year, that is, 17,520. Inspection of this row indicates temporary increases in 'profitability' from 4 per cent in 2024 to a range between 8 and 9 per cent over the 2025 to 2030 period before declining to 4 per cent in 2031. This percentage value then climbs from 5 per cent in 2035 to 10 per cent in 2036 and then further to 19 per cent in years 2037 and 2038, before declining to 4 per cent over years 2040 to 2047. Clearly, these temporary increases in the profitability of the gas component of the hybrid plant accompany the periods of temporary increase in average spot prices associated with the refurbishment of Gladstone, Tarong and Callide B power stations, as discussed in Section 5.2.

Table 29 shows the monthly count of the number of half-hours that the wholesale spot prices exceed the SRMC of the gas plant for the reference prices gas scenario. The percentage number of exceedances indicates that operating the plant November to February and July and August are the most profitable periods to operate.

Table 29: By month - count of half-hourly wholesale spot price exceedance of SRMC for reference gas price

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Jan	124	122	121	121	121	121	117	117	226	226	226	257	233	207	121	154	148
Feb	215	212	212	212	212	212	208	208	351	351	351	391	363	323	211	236	234
Mar	0	0	0	0	0	0	0	0	73	73	73	86	78	56	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	5	5	5	5	5	5	5	5	39	39	39	39	39	39	5	5	5
Jul	75	75	75	75	75	75	75	75	160	160	160	160	160	160	75	75	75
Aug	47	47	47	47	47	47	44	44	130	130	130	132	131	128	46	47	47
Sep	3	3	3	3	3	3	2	2	6	6	6	7	6	6	3	3	3
Oct	0	0	0	0	0	0	0	0	3	3	3	42	6	3	0	0	0
Nov	45	41	41	41	41	41	36	36	118	118	118	156	134	113	39	65	54
Dec	239	238	238	238	238	238	238	238	376	376	376	387	376	376	238	259	251
Total	753	743	742	742	742	742	725	725	1,482	1,482	1,482	1,658	1,526	1,411	738	844	817

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	total	%
Jan	148	148	271	417	417	271	124	124	119	119	119	119	119	119	5,396	15%
Feb	234	234	384	530	530	384	213	213	209	209	209	209	209	209	8,478	24%
Mar	0	0	126	285	285	126	0	0	0	0	0	0	0	0	1,261	4%
Apr	0	0	1	8	8	1	0	0	0	0	0	0	0	0	19	0%
May	0	0	1	69	69	1	0	0	0	0	0	0	0	0	140	0%
Jun	5	5	66	284	284	66	5	5	5	5	5	5	5	5	1,039	3%
Jul	75	75	199	418	418	199	75	75	75	75	75	75	75	75	3,769	11%
Aug	47	47	159	331	331	159	46	46	45	45	45	45	45	45	2,727	8%
Sep	3	3	8	79	79	8	3	3	2	2	2	2	2	2	266	1%
Oct	0	0	20	102	102	20	0	0	0	0	0	0	0	0	304	1%
Nov	54	54	160	324	324	160	42	42	36	36	36	36	36	36	2,613	7%
Dec	251	251	393	547	547	393	239	239	238	238	238	238	238	238	9,208	26%
Total	817	817	1,788	3,394	3,394	1,788	747	747	729	729	729	729	729	729	35,220	100%

Table 30 shows the count of the number of half-hours by hour that the wholesale spot prices exceed the SRMC of the gas plant for the reference prices gas scenario. The percentage number of exceedances indicates that operating the plant between 7 am and 10 pm will capture 99% of the exceedances.

Table 30: By hour - count of half-hourly wholesale spot price exceedance of SRMC for reference gas price

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
12 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 AM	7	7	7	7	7	7	4	4	15	15	15	16	16	13	6	7	7
8 AM	19	19	19	19	19	19	19	19	53	53	53	61	53	51	19	19	19
9 AM	13	12	12	12	12	12	12	12	77	77	77	93	79	73	12	21	18
10 AM	32	31	30	30	30	30	28	28	89	89	89	107	91	85	32	43	39
11 AM	50	48	48	48	48	48	48	48	100	100	100	120	104	94	48	63	59
12 PM	62	60	60	60	60	60	60	60	118	118	118	138	124	108	60	75	69
1 PM	70	70	70	70	70	70	69	69	132	132	132	149	137	123	70	86	82
2 PM	88	87	87	87	87	87	85	85	139	139	139	155	141	131	86	100	98
3 PM	88	88	88	88	88	88	86	86	130	130	130	143	137	122	86	97	95
4 PM	85	84	84	84	84	84	81	81	128	128	128	139	133	121	84	88	88
5 PM	79	78	78	78	78	78	76	76	112	112	112	127	113	107	77	80	79
6 PM	59	58	58	58	58	58	56	56	133	133	133	140	136	132	57	61	61
7 PM	51	51	51	51	51	51	51	51	128	128	128	138	134	126	51	54	53
8 PM	37	37	37	37	37	37	37	37	91	91	91	95	91	89	37	37	37
9 PM	12	12	12	12	12	12	12	12	36	36	36	36	36	35	12	12	12
10 PM	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11 PM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	753	743	742	742	742	742	725	725	1,482	1,482	1,482	1,658	1,526	1,411	738	844	817

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Total	%
12 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
1 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
2 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
3 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
4 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
5 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
6 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
7 AM	7	7	24	58	58	24	6	6	5	5	5	5	5	5	380	1%
8 AM	19	19	69	185	185	69	19	19	19	19	19	19	19	19	1,231	3%
9 AM	18	18	98	244	244	98	14	14	12	12	12	12	12	12	1,444	4%
10 AM	39	39	110	237	237	110	33	33	30	30	30	30	30	30	1,921	5%
11 AM	59	59	126	218	218	126	48	48	48	48	48	48	48	48	2,364	7%
12 PM	69	69	142	217	217	142	61	61	60	60	60	60	60	60	2,748	8%
1 PM	82	82	154	223	223	154	70	70	69	69	69	69	69	69	3,073	9%
2 PM	98	98	159	229	229	159	88	88	85	85	85	85	85	85	3,479	10%
3 PM	95	95	152	225	225	152	87	87	86	86	86	86	86	86	3,404	10%
4 PM	88	88	148	220	220	148	84	84	81	81	81	81	81	81	3,270	9%
5 PM	79	79	134	280	280	134	78	78	77	77	77	77	77	77	3,144	9%
6 PM	61	61	163	348	348	163	58	58	56	56	56	56	56	56	3,043	9%
7 PM	53	53	153	335	335	153	51	51	51	51	51	51	51	51	2,838	8%
8 PM	37	37	111	235	235	111	37	37	37	37	37	37	37	37	2,017	6%
9 PM	12	12	42	112	112	42	12	12	12	12	12	12	12	12	775	2%
10 PM	1	1	3	27	27	3	1	1	1	1	1	1	1	1	87	0%
11 PM	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0%
Total	817	817	1,788	3,394	3,394	1,788	747	747	729	729	729	729	729	729	35,220	100%

5.6 How sensitive is the plant's revenue to gas as bridging technology

In Section 4.5, we find that the total variable cost of the gas component of the proposed plant exceed its revenue given the proposed dispatch profile in Table 3. In this section, we investigate wholesale spot prices for the years 2017-47 to find a more profitable dispatch profile for the plant given the "gas as a bridging technology" scenario. Table 31 shows the day of the week count of the number of half hours that the wholesale spot prices exceed the SRMC of the gas plant for the reference prices gas scenario. The number of exceedances indicates that operating the plant Monday through Friday still is the most profitable period to operate but the operating during the weekends becomes worthwhile considering operating. Note again that the final row of the table expresses the number of exceedances as a percentage of the total number of half hours in each year.

Table 31: By day of the week - count of half-hourly wholesale spot price exceedance of SRMC for gas as bridging technology

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Sunday	24	24	24	24	24	24	24	24	191	191	191	210	210	210	210	303	303
Monday	177	177	177	177	177	177	173	173	902	902	902	998	998	998	998	1,144	1,144
Tuesday	158	152	152	152	152	152	148	148	905	905	905	981	981	981	981	1,221	1,221
Wednesday	139	138	137	137	137	137	135	135	866	866	866	933	933	933	933	1,112	1,112
Thursday	143	141	141	141	141	141	135	135	852	852	852	952	952	952	952	1,065	1,065
Friday	85	84	84	84	84	84	83	83	678	678	678	713	713	713	713	885	885
Saturday	27	27	27	27	27	27	27	27	170	170	170	203	203	203	203	345	345
Total	753	743	742	742	742	742	725	725	4,564	4,564	4,564	4,990	4,990	4,990	4,990	6,075	6,075
Percent	4%	4%	4%	4%	4%	4%	4%	4%	26%	26%	26%	28%	28%	28%	28%	35%	35%

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Total	%
Sun	303	303	1039	1440	1440	1440	1454	1454	1454	1454	1454	1454	1454	1454	19,808	9%
Mon	1144	1144	1690	1800	1800	1800	1807	1807	1807	1807	1807	1807	1807	1807	34,228	16%
Tue	1221	1221	1863	1985	1985	1985	1985	1985	1985	1985	1985	1985	1985	1985	36,435	17%
Wed	1112	1112	1815	1943	1943	1943	1948	1948	1948	1948	1948	1948	1948	1948	35,101	17%
Thu	1065	1065	1698	1813	1813	1813	1815	1815	1815	1815	1815	1815	1815	1815	33,399	16%
Fri	885	885	1577	1706	1706	1706	1716	1716	1716	1716	1716	1716	1716	1716	29,520	14%
Sat	345	345	1280	1608	1608	1608	1620	1620	1620	1620	1620	1620	1620	1620	21,982	10%
Tot	6075	6075	10962	12295	12295	12295	12345	12345	12345	12345	12345	12345	12345	12345	210,473	100%
Percent	35%	35%	63%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	36%	

It is apparent that a number of permanent jumps in ‘profitability’ occur in the table: 2025 (e.g. 4 to 26 per cent); 2028 (26 to 28 per cent); 2032 (28 to 35 per cent); 2036 (35 to 63 per cent); and 2037 (63 to 70 per cent). Note further that the percentage ‘profitability’ rate remains at around 70 per cent over the remainder of the time horizon out to 2047, reinforcing the permanency of this trend increase over time.

The magnitude of percentage increases are also very notable when compared with those for the reference gas prices listed in Table 28 in the previous Section 5.5. In particular, the most notable increases in Table 28 occur during the periods 2025-30 and 2036-39 encompassing percentages values in the range of 8 to 9 per cent and between 10 and 19 per cent, respectively. The comparable figures in Table 31 are an order of magnitude larger with percentage values of 26 to 28 and 63 to 70 per cent, respectively. This results signify that the spot price up-lift associated with the permanent replacement of old coal plant with new but more expensive CCGT plant has markedly improved the profitability of the gas component of the Collinsville hybrid plant. A contributing factor for this is that the escalation in gas costs for the hybrid plant is below the cost escalation associated with gas prices of new entrant CCGT plant, which is linked to domestically traded gas prices assumed for this new entrant gas plant.

Table 32 shows the monthly count of the number of half-hours that the wholesale spot prices exceed the SRMC of the gas plant for the gas as a bridging technology scenario. Operating the plant through the year is a consideration given the monthly distribution exceedances. However, November to February and June to August are the most profitable periods to operate.

Table 32: By month - count of half-hourly wholesale spot price exceedance of SRMC for gas as bridging technology

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Jan	124	122	121	121	121	121	117	117	504	504	504	579	579	579	579	750	750
Feb	215	212	212	212	212	212	208	208	638	638	638	659	659	659	659	761	761
Mar	0	0	0	0	0	0	0	0	383	383	383	451	451	451	451	506	506
Apr	0	0	0	0	0	0	0	0	41	41	41	101	101	101	101	264	264
May	0	0	0	0	0	0	0	0	127	127	127	151	151	151	151	169	169
Jun	5	5	5	5	5	5	5	5	425	425	425	445	445	445	445	447	447
Jul	75	75	75	75	75	75	75	75	538	538	538	543	543	543	543	545	545
Aug	47	47	47	47	47	47	44	44	441	441	441	454	454	454	454	460	460
Sep	3	3	3	3	3	3	2	2	197	197	197	257	257	257	257	366	366
Oct	0	0	0	0	0	0	0	0	211	211	211	262	262	262	262	501	501
Nov	45	41	41	41	41	41	36	36	425	425	425	447	447	447	447	588	588
Dec	239	238	238	238	238	238	238	238	634	634	634	641	641	641	641	718	718
Total	753	743	742	742	742	742	725	725	4564	4564	4564	4990	4990	4990	4990	6075	6075

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	total	%
Jan	750	750	1012	1080	1080	1080	1080	1080	1080	1080	1080	1080	1080	1080	20684	10%
Feb	761	761	957	1008	1008	1008	1012	1012	1012	1012	1012	1012	1012	1012	21362	10%
Mar	506	506	875	1001	1001	1001	1012	1012	1012	1012	1012	1012	1012	1012	16951	8%
Apr	264	264	743	904	904	904	917	917	917	917	917	917	917	917	12374	6%
May	169	169	790	945	945	945	945	945	945	945	945	945	945	945	12846	6%
Jun	447	447	929	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050	17362	8%
Jul	545	545	987	1106	1106	1106	1106	1106	1106	1106	1106	1106	1106	1106	19719	9%
Aug	460	460	951	1097	1097	1097	1097	1097	1097	1097	1097	1097	1097	1097	18367	9%
Sep	366	366	853	986	986	986	987	987	987	987	987	987	987	987	14812	7%
Oct	501	501	849	970	970	970	979	979	979	979	979	979	979	979	15276	7%
Nov	588	588	965	1042	1042	1042	1045	1045	1045	1045	1045	1045	1045	1045	18188	9%
Dec	718	718	1051	1106	1106	1106	1115	1115	1115	1115	1115	1115	1115	1115	22532	11%
Total	6075	6075	10962	12295	12295	12295	12345	12345	12345	12345	12345	12345	12345	12345	210473	100%

Table 33 shows the count of the number of half-hours by hour that the wholesale spot prices exceed the SRMC of the gas plant for gas as a bridging technology scenario. The percentage number of exceedances indicates that operating the plant between 7 am and 10 pm will capture 92% of the exceedances. However, extending the current operation profile beyond 10 pm becomes a consideration given the number of exceedances past 10 pm.

Table 33: By hour - count of half-hourly wholesale spot price exceedance of SRMC for gas as bridging technology

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
12 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 AM	7	7	7	7	7	7	4	4	90	90	90	110	110	110	110	152	152
8 AM	19	19	19	19	19	19	19	19	268	268	268	306	306	306	306	388	388
9 AM	13	12	12	12	12	12	12	12	327	327	327	351	351	351	351	432	432
10 AM	32	31	30	30	30	30	28	28	341	341	341	367	367	367	367	443	443
11 AM	50	48	48	48	48	48	48	48	326	326	326	353	353	353	353	426	426
12 PM	62	60	60	60	60	60	60	60	278	278	278	311	311	311	311	388	388
1 PM	70	70	70	70	70	70	69	69	274	274	274	296	296	296	296	355	355
2 PM	88	87	87	87	87	87	85	85	275	275	275	301	301	301	301	351	351
3 PM	88	88	88	88	88	88	86	86	262	262	262	278	278	278	278	338	338
4 PM	85	84	84	84	84	84	81	81	279	279	279	305	305	305	305	368	368
5 PM	79	78	78	78	78	78	76	76	386	386	386	421	421	421	421	495	495
6 PM	59	58	58	58	58	58	56	56	449	449	449	485	485	485	485	565	565
7 PM	51	51	51	51	51	51	51	51	445	445	445	488	488	488	488	559	559
8 PM	37	37	37	37	37	37	37	37	331	331	331	370	370	370	370	462	462
9 PM	12	12	12	12	12	12	12	12	181	181	181	194	194	194	194	280	280
10 PM	1	1	1	1	1	1	1	1	50	50	50	52	52	52	52	71	71
11 PM	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2
Total	753	743	742	742	742	742	725	725	4564	4564	4564	4990	4990	4990	4990	6075	6075

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Total	%
12 AM	0	0	57	257	257	257	262	262	262	262	262	262	262	262	2924	1%
1 AM	0	0	2	20	20	20	24	24	24	24	24	24	24	24	254	0%
2 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
3 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
4 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
5 AM	0	0	0	1	1	1	1	1	1	1	1	1	1	1	11	0%
6 AM	0	0	99	222	222	222	226	226	226	226	226	226	226	226	2573	1%
7 AM	152	152	489	538	538	538	538	538	538	538	538	538	538	538	7775	4%
8 AM	388	388	596	654	654	654	656	656	656	656	656	656	656	656	11538	5%
9 AM	432	432	668	707	707	707	710	710	710	710	710	710	710	710	12679	6%
10 AM	443	443	682	721	721	721	721	721	721	721	721	721	721	721	13115	6%
11 AM	426	426	675	717	717	717	717	717	717	717	717	717	717	717	13042	6%
12 PM	388	388	655	711	711	711	714	714	714	714	714	714	714	714	12612	6%
1 PM	355	355	631	703	703	703	708	708	708	708	708	708	708	708	12388	6%
2 PM	351	351	620	689	689	689	691	691	691	691	691	691	691	691	12341	6%
3 PM	338	338	618	695	695	695	696	696	696	696	696	696	696	696	12221	6%
4 PM	368	368	648	714	714	714	719	719	719	719	719	719	719	719	12738	6%
5 PM	495	495	715	728	728	728	730	730	730	730	730	730	730	730	14182	7%
6 PM	565	565	728	729	729	729	730	730	730	730	730	730	730	730	14763	7%
7 PM	559	559	728	730	730	730	730	730	730	730	730	730	730	730	14689	7%
8 PM	462	462	716	729	729	729	729	729	729	729	729	729	729	729	13352	6%
9 PM	280	280	696	723	723	723	725	725	725	725	725	725	725	725	11200	5%
10 PM	71	71	580	696	696	696	698	698	698	698	698	698	698	698	8902	4%
11 PM	2	2	359	611	611	611	620	620	620	620	620	620	620	620	7174	3%
Total	6075	6075	10962	12295	12295	12295	12345	12345	12345	12345	12345	12345	12345	12345	210473	100%

5.7 How sensitive is the plant's revenue to higher gas prices?

In Section 4.5, we find that the total variable cost of the gas component of the proposed plant exceed its revenue given the proposed dispatch profile in Table 3. In this section, we investigate wholesale spot prices for the years 2017-47 to find a more profitable dispatch profile for the plant given the "high gas price" scenario. Table 34 shows the day of the week count of the number of half hours that the wholesale spot prices exceed the SRMC of the gas plant for the high prices gas scenario. The percentage number of exceedances indicates that operating the plant Monday through Friday is the most profitable period to operate with 92% of all exceedances.

Table 34: By day of the week - count of half-hourly wholesale spot price exceedance of SRMC for high gas price

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Sunday	32	32	32	32	32	32	32	32	61	61	61	63	61	61	32	32	32
Monday	243	230	229	230	229	230	222	222	412	412	412	463	423	396	223	247	242
Tuesday	215	209	208	209	208	209	200	200	433	433	433	475	440	398	203	254	251
Wednesday	189	189	189	189	188	189	187	187	417	417	417	460	434	384	188	228	224
Thursday	186	182	182	182	182	182	179	179	389	389	389	425	399	351	184	215	209
Friday	140	136	136	136	136	136	133	133	305	305	305	337	313	287	135	155	153
Saturday	35	35	35	35	35	35	35	35	62	62	62	70	64	61	35	39	38
Total	1040	1013	1011	1013	1010	1013	988	988	2079	2079	2079	2293	2134	1938	1000	1170	1149
Percent	6%	6%	6%	6%	6%	6%	6%	6%	12%	12%	12%	13%	12%	11%	6%	7%	7%

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Total	%
Sunday	32	32	71	162	162	71	32	32	32	32	32	32	32	32	1,506	3%
Monday	242	242	494	807	807	494	230	230	223	223	223	223	223	223	9,949	21%
Tuesday	251	251	506	834	834	506	209	209	203	203	203	203	203	203	9,796	21%
Wednesday	224	224	490	823	823	490	188	188	188	188	188	188	188	188	9,254	19%
Thursday	209	209	460	765	765	460	185	185	180	180	180	180	180	180	8,722	18%
Friday	153	153	359	619	619	359	137	137	134	134	134	134	134	134	6,721	14%
Saturday	38	38	71	145	144	71	35	35	35	35	35	35	35	35	1,560	3%
Total	1149	1149	2451	4155	4154	2451	1016	1016	995	995	995	995	995	995	47,508	100%
Percent	7%	7%	14%	24%	24%	14%	6%	6%	6%	6%	6%	6%	6%	6%	8%	

Once again, the final row of the table expresses the number of exceedances as a percentage of the total number of half hours in each year. The results in this row share many of the characteristics of the similar row in Table 28. In particular, discrete but temporary increases in percentage ‘profitability’ are observed over years 2025-30 and 2036-39. However, the percentage values in Table 34 are of a slightly higher magnitude than the corresponding values listed in Table 19. Specifically, in Table 34 the percentage values are in the range of 11 to 13 per cent and 14 to 24 per cent respectively, for these two particular time intervals. These values are up from the equivalent ranges of 8 to 9 per cent and 10 to 19 per cent listed in Table 28. The slight increases in the percentage values listed in Table 34 relative to Table 28 reflect the slightly higher up-lift in average spot prices induced by the higher gas prices applicable under the high gas price scenario when compared with the slightly lower gas prices applicable under the “reference gas price” scenario. However, apart from this, the results in Table 34 qualitatively match those in Table 28. In contrast, they do not record the degree or permanency of magnitude of the increase in the percentage values recorded in Table 31 for the “gas a bridging technology” scenario.

Table 35 shows the monthly count of the number of half-hours that the wholesale spot prices exceed the SRMC of the gas plant for the high gas prices scenario. The percentage number of exceedances indicates that operating the plant November to March and June and August are the most profitable periods to operate with 96% of exceedances.

Table 35: By month - count of half-hourly wholesale spot price exceedance of SRMC for high gas price scenario

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Jan	170	169	168	169	167	169	162	162	316	316	316	352	327	299	165	208	201
Feb	275	266	266	266	266	266	263	263	416	416	416	461	426	385	267	312	306
Mar	0	0	0	0	0	0	0	0	164	164	164	189	173	114	0	3	3
Apr	0	0	0	0	0	0	0	0	1	1	1	5	3	0	0	0	0
May	0	0	0	0	0	0	0	0	6	6	6	6	6	6	0	0	0
Jun	13	13	13	13	13	13	13	13	91	91	91	91	91	85	13	13	13
Jul	103	103	103	103	103	103	103	103	221	221	221	222	222	221	103	103	103
Aug	75	75	75	75	75	75	73	73	179	179	179	184	180	175	74	75	75
Sep	5	5	5	5	5	5	3	3	9	9	9	13	11	6	5	5	5
Oct	9	0	0	0	0	0	0	0	35	35	35	80	39	16	0	17	16
Nov	85	81	80	81	80	81	70	70	199	199	199	235	211	190	72	107	103
Dec	305	301	301	301	301	301	301	301	442	442	442	455	445	441	301	327	324
Total	1,040	1,013	1,011	1,013	1,010	1,013	988	988	2,079	2,079	2,079	2,293	2,134	1,938	1,000	1,170	1,149

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	total	%
Jan	201	201	359	471	471	359	170	170	164	164	164	164	164	164	7,222	15%
Feb	306	306	445	599	599	445	268	268	264	264	264	264	264	264	10,356	22%
Mar	3	3	235	338	338	235	0	0	0	0	0	0	0	0	2,126	4%
Apr	0	0	4	22	22	4	0	0	0	0	0	0	0	0	63	0%
May	0	0	12	99	99	12	0	0	0	0	0	0	0	0	258	1%
Jun	13	13	138	399	399	138	13	13	13	13	13	13	13	13	1,887	4%
Jul	103	103	261	516	516	261	103	103	103	103	103	103	103	103	5,045	11%
Aug	75	75	219	413	413	219	75	75	74	74	74	74	74	74	3,904	8%
Sep	5	5	22	156	156	22	5	5	4	4	4	4	4	4	508	1%
Oct	16	16	62	167	167	62	0	0	0	0	0	0	0	0	772	2%
Nov	103	103	231	375	375	231	81	81	72	72	72	72	72	72	4,155	9%
Dec	324	324	463	600	599	463	301	301	301	301	301	301	301	301	11,212	24%
Total	1,149	1,149	2,451	4,155	4,154	2,451	1,016	1,016	995	995	995	995	995	995	47,508	100%

Table 36 shows the count of the number of half-hours by hour that the wholesale spot prices exceed the SRMC of the gas plant for the high gas price scenario. The percentage number of exceedances indicates that operating the plant between 7 am and 10 pm will capture 99% of the exceedances.

Table 36: By hour - count of half-hourly wholesale spot price exceedance of SRMC for high gas price scenario

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
12 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 AM	12	12	12	12	12	12	10	10	26	26	26	29	26	23	11	12	12
8 AM	36	36	36	36	36	36	36	36	87	87	87	103	89	80	36	39	38
9 AM	32	30	30	30	30	30	28	28	126	126	126	152	134	117	30	50	44
10 AM	52	48	48	48	48	48	48	48	128	128	128	156	137	115	48	71	65
11 AM	67	64	64	64	64	64	62	62	146	146	146	164	151	128	62	88	85
12 PM	91	87	87	87	87	87	83	83	161	161	161	181	167	148	86	106	106
1 PM	99	97	97	97	97	97	95	95	174	174	174	189	176	160	96	111	111
2 PM	106	104	104	104	104	104	102	102	178	178	178	193	181	168	102	118	117
3 PM	107	106	106	106	106	106	104	104	172	172	172	182	175	162	106	117	117
4 PM	107	104	104	104	104	104	103	103	167	167	167	179	170	156	103	115	115
5 PM	98	95	94	95	93	95	93	93	159	159	159	177	166	149	93	102	100
6 PM	83	82	82	82	82	82	80	80	196	196	196	209	199	186	81	86	85
7 PM	74	72	71	72	71	72	71	71	173	173	173	185	175	167	71	77	77
8 PM	56	56	56	56	56	56	53	53	127	127	127	131	128	121	55	58	57
9 PM	19	19	19	19	19	19	19	19	54	54	54	57	55	53	19	19	19
10 PM	1	1	1	1	1	1	1	1	5	5	5	6	5	5	1	1	1
11 PM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,040	1,013	1,011	1,013	1,010	1,013	988	988	2,079	2,079	2,079	2,293	2,134	1,938	1,000	1,170	1,149

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Total	%
12 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
1 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
2 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
3 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
4 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
5 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
6 AM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0%
7 AM	12	12	30	72	72	30	12	12	11	11	11	11	11	11	601	1%
8 AM	38	38	111	239	239	111	36	36	36	36	36	36	36	36	1,998	4%
9 AM	44	44	169	301	301	169	31	31	29	29	29	29	29	29	2,407	5%
10 AM	65	65	167	318	318	167	48	48	48	48	48	48	48	48	2,848	6%
11 AM	85	85	168	300	300	168	65	65	62	62	62	62	62	62	3,235	7%
12 PM	106	106	182	264	264	182	88	88	86	86	86	86	86	86	3,765	8%
1 PM	111	111	195	252	252	195	99	99	95	95	95	95	95	95	4,023	8%
2 PM	117	117	197	244	244	197	104	104	102	102	102	102	102	102	4,179	9%
3 PM	117	117	189	247	247	189	107	107	105	105	105	105	105	105	4,170	9%
4 PM	115	115	184	253	253	184	104	104	103	103	103	103	103	103	4,102	9%
5 PM	100	100	184	351	351	184	93	93	93	93	93	93	93	93	4,034	8%
6 PM	85	85	231	416	416	231	82	82	81	81	81	81	81	81	4,201	9%
7 PM	77	77	210	396	396	210	71	71	71	71	71	71	71	71	3,779	8%
8 PM	57	57	157	301	301	157	56	56	53	53	53	53	53	53	2,833	6%
9 PM	19	19	66	160	159	66	19	19	19	19	19	19	19	19	1,177	2%
10 PM	1	1	11	40	40	11	1	1	1	1	1	1	1	1	154	0%
11 PM	0	0	0	1	1	0	0	0	0	0	0	0	0	0	2	0%
Total	1,149	1,149	2,451	4,155	4,154	2,451	1,016	1,016	995	995	995	995	995	995	47,508	100%

5.8 What is the Levelised Cost of Energy?

Section 4.8 in the results section discusses the financial feasibility of the project and the PPA strike prices needed to ensure feasibility reflect a number of considerations including:

- the dispatch profile outlined in Table 3;
- the yield for the LFR determined in our previous report (Bell, Wild & Foster 2014b) and requirement for the gas component to 'top-up' dispatch to meet that in Table 3;
- the very high ($/KW) 'overnight' capital cost of the hybrid plant when compared with equivalent costs of mature thermal and second generation renewable generation technologies;
- assumptions made about demand including lack of growth in total demand;
- least-cost dispatch based upon SRMC bidding of thermal generation; and
- the ability and adequacy of commercial based PPA arrangements based upon mature competitive generation technologies to adequately cover the LCOE of what is an infant generation technology, at least, in terms of cost and operational capacity in the NEM.

If conditions diverge from these assumptions, the required PPA strike prices for financial feasibility of the project may change. Specifically, a number of factors might work to reduce the levels of the PPA strike prices below the values determined in this report. These factors include:

- Increased dispatch of the solar component relative to the levels reported in this report associated with the TYM. This would increase both revenue and feasibility because:
    - the PPA strike price for the solar energy is higher than that associated with the gas component, thus producing higher amounts of PPA revenue; and
    - the wholesale market position would be improved by the increased dispatch of lower cost solar component and lower dispatch of the more costly gas component in its top-up role;
- We saw how temporary capacity withdrawals over years 2037-2038 could increase average wholesale spot prices significantly. This raises the possibility of strategic behaviour on the part of generators through either the manipulation of the supply offers above SRMC's or capacity manipulation being used to increase wholesale spot prices and wholesale market profitability. This would place downward pressure on the required PPA prices needed to ensure project feasibility. However, it should also be recognized that strategic bidding becomes more difficult in times of serious over supply of generation capacity and declining peak and average demand, which currently characterizes the situation confronting the NEM.
- If demand growth turn out to be higher in extent than implicitly assumed in this report. In particular, if the current downward trend in both average and peak demand turns around and growth in total demand were to emerge, then we could expect wholesale market prices to increase. This, in turn, would place downward pressure on the PPA strike prices required to ensure financial feasibility of the project.

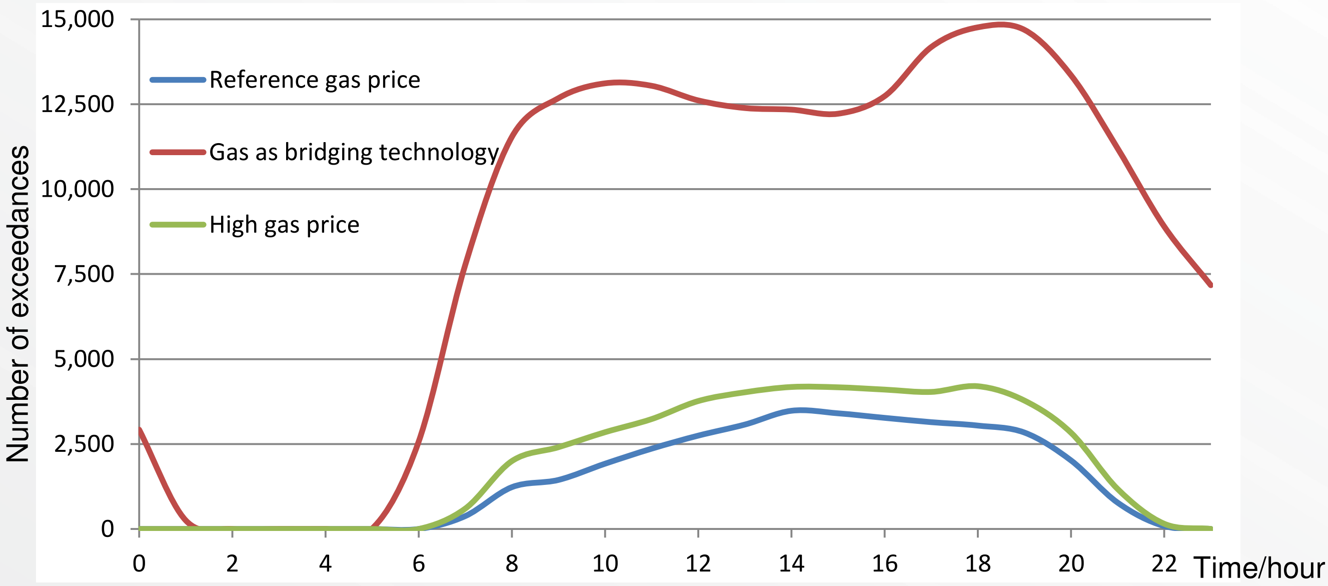
Nevertheless, there are sufficient grounds to investigate alterative dispatch profiles to that in Table 3.

5.9 Comparing scenarios by hour, month and day of week

Sections 5.5, 5.6 and 5.7 discuss the three scenarios independently where we analysis the wholesale market spot prices exceedance of the gas plant's SRMC to help evaluate the suitability of the proposed dispatch profile in Table 3 to maximise short-run profit for the gas component. In contrast, in this section, we compare the exceedances in the three scenarios by hour, by month and by day of the week.

Figure 14 compares by hour the number of half-hourly wholesale spot market price exceedance of SRMC of the gas generator for the three scenarios.

Figure 14: By hour – number of half-hourly wholesale spot price exceedances of SRMC of gas 2017-47

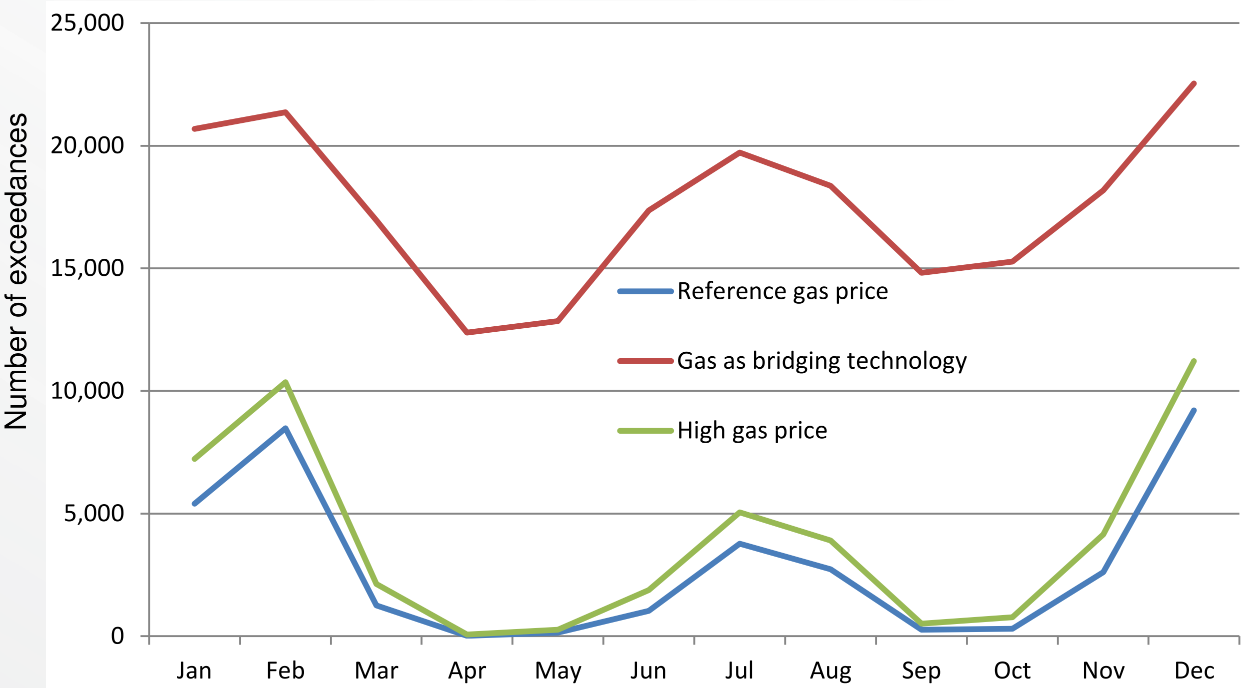


The reference and high gas price scenarios in Figure 14 show that the proposed dispatch profile in Table 3 captures most of the exceedances but fails to capture the exceedance in the "gas as a bridging technology" scenario.

However, the number of exceedances increases with time, which requires an NPV analysis to discount the heavy weighting of profits in later years, see Figure 13. This effect is particularly marked in the gas as a bridging technology scenario. Additionally, the duration of the PPA needs consideration because the duration will determine the profitability of differing profiles. The plant will likely require support of a PPA especially during the initial phase of the project over years 2017 to 2024 where significant penetration of low cost coal generation remains likely.

Figure 15 compares by month the number of half-hourly wholesale spot market price exceedance of SRMC for the gas generator for the three scenarios. In the reference and high gas price scenarios, Figure 15 shows that April, May and September lack any exceedances making them loss-making months in which to operate the gas component of the plant. The bordering months March, June and October are marginally more profitable than April, May and September. As discussed, there is a bias in the high number of exceedances in the "gas as a bridging technology" toward later years that necessitates a NPV analysis.

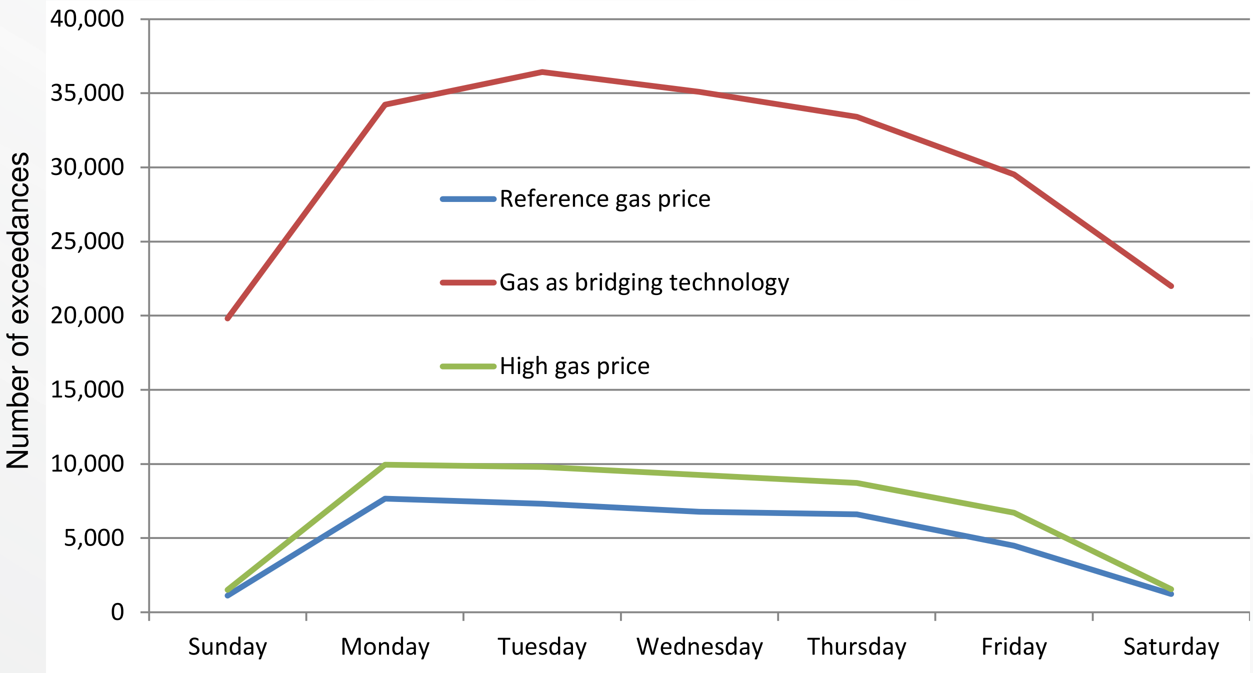
Figure 15: By month – number of half-hourly wholesale spot price exceedances of SRMC of gas for 2017-47



The reason for the unexpectedly lower number of exceedances in January than in February or December is discussed in our previous report (Bell, Wild & Foster 2014b, sec. 7.8) where we calculated the typical meteorological year (TMY) for use in this report. The TMY comprises 12 months selected from the years 2007-13. The Januaries and Februaries in these years have the lowest total monthly DNI energy of any other months on average and the Typical Metrological Month (TMM) section process chose a January with slightly less monthly DNI energy than the February. Hence, the wholesale spot prices are lower in January than December or February.

Figure 16 compares by day of week the number of half-hourly wholesale spot market price exceedance of SRMC for the gas generator for three scenarios. In the reference and high gas price scenarios, Figure 16 shows that Saturday and Sunday lack any exceedances making them loss-making days in which to operate the gas component of the plant. Friday is marginally more profitable than Saturday and Sunday. This is consistent with the proposed dispatch profile in Table 3 to operate only during the weekdays. In the "gas as a bridging technology", the replacement of the cheaper old coal-fired generators by the more expensive CCGT plant in the latter years of the lifetime of the proposed plant increases wholesale spot prices and consequently the number of exceedances increase in the latter years. This is especially noticeable from 2035 onwards. This bias of the number of exceedances toward the latter years necessitates a NPV analysis.

Figure 16: By day of week – number of half-hourly wholesale spot price exceedances of SRMC of gas for 2017-47



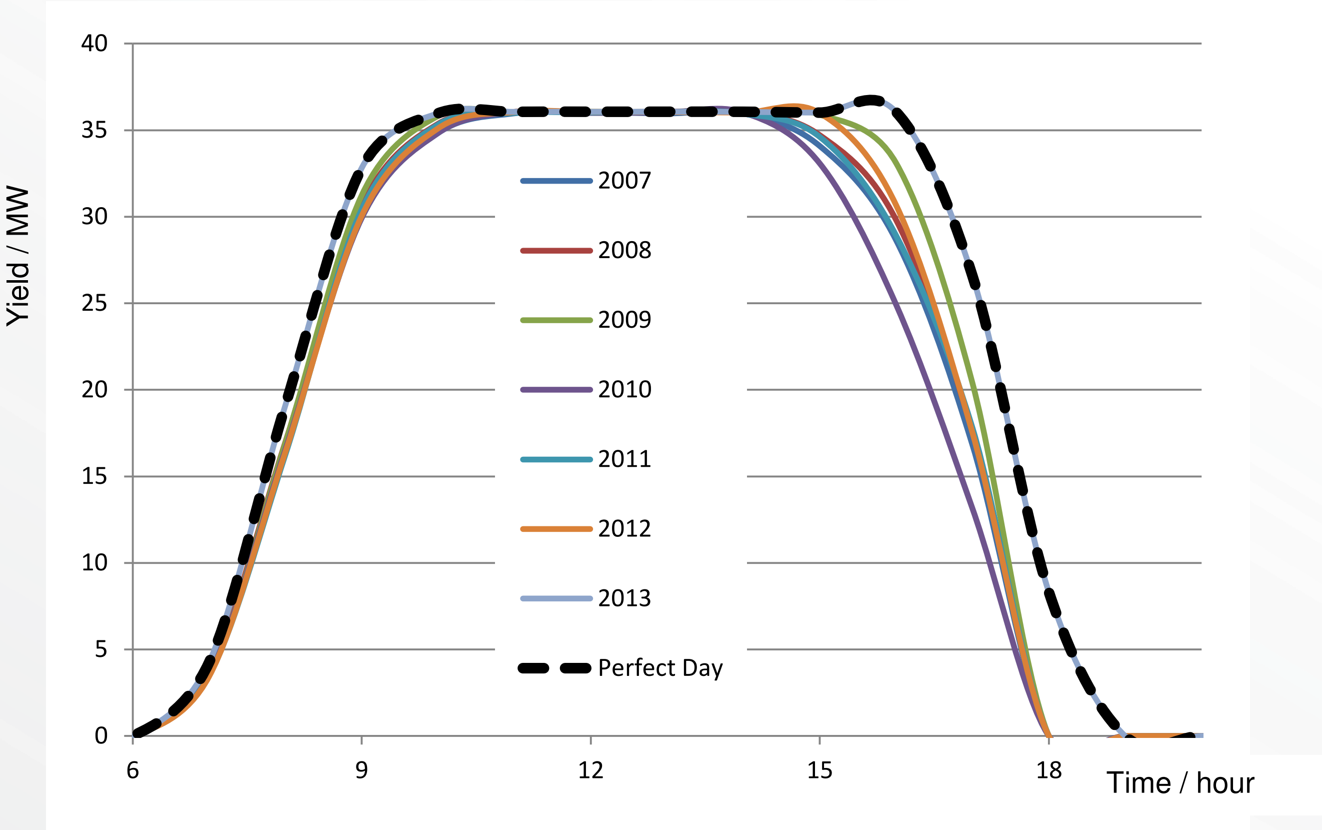
5.10 Imitating a coal baseload function or maximising the strengths and minimising the weakness of LFR and CCGT technologies

The proposed dispatch profile in Table 3 does a reasonable job at approximating the times that the wholesale spot prices exceed the SRMC of the plant's gas component for both the hour of the day and day of week. However, the research shows the proposed profile exhibits considerable weakness in matching exceedances with the month of the year. The current endeavour is to develop a dispatch profile that matches the exceedance profile by toping up the LFR yield with yield from the gas generator. The loss making months of the year for the gas generator to operate highlights a weakness in this demand profile approach or pseudo baseload profile to replace coal generation.

An alternative approach is to use each technology's strength to compensate for the other technology's weakness. For instance, compare the SRMC of the LFR at $1.00/MWh with the SRMC of the gas turbine at $56/MWh and the inflexibility and intermittency of yield from the LFR with the flexibility of the yield from the gas generator.

The alternative approach is to maximise the profit of each component independently but use the gas generator to remove any intermittency from the LRF yield thereby guaranteeing its yield as if it were a perfect yield day every day of the year. The perfect day's yield is the maximum yield for the hour of the day from a number of years. Figure 17 illustrates the development of a perfect day's yield profile composed from the days with the maximum yield from years 2007-13. The black dashed line denotes the perfect day's yield profile and envelopes all the maximum yield days from the years 2007-13, ignoring any minor aberrations caused by Excel's curve fitting algorithm. The perfect yield day profile derives mainly from year 2013. The gas generator tops-up the actual yield from the LFR to the yield expected on a perfect day.

Figure 17: Developing a perfect day's yield profile from the years 2007-13



This approach would provide a very low SRMC for the LFR without intermittency and the gas generator is otherwise free to dispatch at times that wholesale prices exceed SMRC and to take advantage of VOLL events. This approach avoids situations where the gas generator is running at a loss for months and reduces CO_2 production compared to the proposed dispatch profile. The LRF's perfect day yield profile provides certainty and low SRMC for PPA negotiations. The remaining gas generator capacity services periods of relatively high demand when retailers are more willing to enter into a PPA at higher prices to cover the higher SRMC of the gas generator.

Using monthly perfect yield day profiles provides a refinement on the single yearly profile. There are advantages and disadvantages to using monthly profiles rather than a single yearly profile. The monthly profile would more closely fit the actual yield of the plant thereby requiring less gas to fill the gap between actual yield and the profile. Hence, there is a lower SRMC. However, twelve monthly profiles would potentially complicate PPA negotiations.

Physically, the existing transmission capacity at Collinsville can easily accommodate the small excess above 30 MW but legally, non-scheduled status may require the 30 MW maximum. However, there are some non-scheduled wind farms significantly above 30 MW.

We recommend further research that requires compiling monthly perfect day profiles and investigating the ability of the gas generator to respond quickly enough to fill the gap between actual yield and the perfect day's yield profile. BoM (2012) has weather station one-minute DNI data for Rockhampton Aero that would prove useful in developing such a perfect yield day profile rather than relying solely on DNI data derived from satellite imagery. The one-minute solar data for Rockhampton Aero data starts in 1996 and data collections continues. In contrast, the BoM (2013).satellite data starts in 1990 but has far fewer hourly satellite images prior to 2007, which reduces the accuracy for developing such a profile. We discuss and contrast in detail these two sources of DNI data in our previous report on yield forecasting (Bell, Wild & Foster 2014b).

Additionally, it is probable that there are loss-making times adjacent to the half hour intervals when wholesale spot prices exceed the SRMC of the plant's gas. Therefore, we need also to consider the loss making half-hours when optimising dispatch regimes. After establishing the profitability of certain periods, the gas component can target these peak load events. This assumes that peak-load periods are forecastable and that the gas plant can operate as a peak-load plant. In summary, the gas would have two operating regimes to meet peak-load demand possibly independently of the LFR and to top-up the LFR when it is operating during the day.

6 Conclusion

The proposed hybrid gas-solar thermal plant for Collinsville, Queensland is part of the transformation of the National Electricity Market (NEM) driven by technological change and the requirement to address climate change discussed in Section 2.2. The two largest proposed generation projects by type are open cycle gas turbines (OCGT) and wind turbine generators (WTG). Both could meet climate change requirements but the recent linkage of gas prices to international prices via the export of liquefied natural gas (LNG) and the continuing fall in electricity demand traded via the NEM makes OCGT uneconomic. This leaves WTG to help the NEM transition from high emissions to a low carbon future. However, WTG has issues with intermittency and a mismatch between wind speed and electricity demand. We await energy storage developments that can address these WTG issues. Section 2.3 discusses these issues. The proposed plant offers the NEM some diversity both in terms of type of generation and dispatch profile that imitates the baseload role of coal generators, using the gas generator to top-up the intermittent yield from the solar thermal component. The proposed dispatch profile is in Table 3.

However, we analyse forecasts of the frequency at which wholesale spot prices exceed the Short Run Marginal Cost (SRMC) of the gas component over the lifetime of the proposed plant. In the two most likely scenarios, the reference and high gas prices scenarios, we find that the proposed profile matches the exceedances by day of week and hour of day but the profile mismatches exceedances by months of the year. The analysis identifies four months of the year without any exceedances. Dispatch from the gas generator during these months contributes to both profit loss and CO_2 emissions when there is low electricity demand. The months either side of the four months are also marginal. In the more unlikely scenario "gas as a bridging technology", we find that extending the proposed dispatch profile to include weekends and operating from 6 am to midnight may contribute to the profitability of the hybrid plant.

As an alternative to the proposed profile, Section 5.9 introduces the perfect day's yield profile for the Linear Fresnel Reflector (LFR) plant, that is, the day from the years 2007-13 with the maximum yield. The gas plant tops up the actual yield from the LFR yield to the perfect day's yield. The gas plants excess capacity is free to meet Value-of-Lost-Load (VOLL) events and periods of higher demand when the wholesale spot price exceeds the SRMC of the gas generator. The perfect day's yield profile incorporates the advantages of the proposed profile but avoids the periods of profit losing dispatch. We also discuss a refinement on the single perfect day's yield profile, that is, twelve monthly profiles. The advantage is using less gas to maintain the profile allowing further excess capacity in the gas plant to meet VOLL events and periods of high demand. The disadvantage is a power purchase agreement (PPA) that is more complex. The addition of the proposed LFR plant at Collinsville could make a valuable addition to the generation mix in the NEM and the gas component could provide useful flexibility to meet the intermittency of the increasing penetration of renewable energy in the NEM.

We recommend further research into pricing an implementation of the perfect day's yield profile. Additionally, our yield forecasting report (Bell, Wild & Foster 2014b) also makes recommendations relevant to this report.

7 Further research

This section compiles the further research discussed elsewhere in this report.

7.1 Extending the reports TMY based years 2007-12 to include earlier years to remove La Niña bias

Section 2.2.7 discusses how the years 2007-12 used to form the TMY in this report have La Niña bias. So, the current TMY selection will under report the revenue for the proposed plant. In contrast, the years immediately prior to 2007 have El Niño bias. Incorporating earlier years would reduce the current La Niña bias. However, this would require developing disaggregated demand profiles suitable for use by the ANEM model that requires a demand profile for each of the 50 nodes on the NEM shown in Appendix A.

7.2 Wholesale spot price sensitivity to the proposed plant

Section 2.4.1 discusses the sensitivity of the wholesale spot prices to the introduction of the proposed plant. However, we expect this sensitivity to be extremely slight, negligible or trivial.

7.3 Solar water heaters replacing electric water heaters

Section 2.2.2 discusses technological innovation transforming the AEMO's "total" demand curve. One such innovation is the replacement of electric water heaters (EWH) with solar water heaters (SWH) where SWH shave demand from the early hours of the morning or other off-peak periods when EWH traditionally operated. Section 3.2.1.1 discusses grossing up the demand profile for large non-scheduled WTG. The CER (2012) database of monthly MW installation of SWH by postcode provides a means to modify the 2007-12 demand profiles as if they were all endowed with the December 2013 level of SWH. This would provide a more accurate rendition of demand curves for modelling.

7.4 Poor correlation between wind speed and demand requiring more transmission (1)

Table 8 shows the lack of correlation between wind speed and demand. However, WTG through the merit order effect does put downward pressure on wholesale market prices. However, transmission bottlenecks hamper market benefit and further deployment of WTG is likely to exacerbate these bottlenecks. This situation requires further research into the dynamics between the transmission structure, wind speed and demand to optimise market benefit.

7.5 Poor correlation between wind speed and demand requiring more transmission (2)

Table 8 and Table 9 show the effect of WTG on South Australia's wholesale spot process. This trend needs revaluating with more up to date data to capture the adaptive changes in transmission and generation.

7.6 Small non-scheduled solar PV and WTG

Section 2.2.2 discusses technological innovation transforming the AEMO's "total" demand curve. Two other such innovations transforming the total demand curve are the installation of small non-scheduled solar PV and WTG. Section 3.2.1.1 discusses grossing up the demand profiled for large non-scheduled WTG. The CER (2012) database of monthly MW installation of small non-scheduled solar PV and WTG by postcode provides a means to modify the 2007-12 demand profiles as if they were all endowed with the December 2013 level of installation. This would provide a more accurate rendition of demand curves for modelling. We discuss the process in a previous report (Bell & Wild 2013).

7.7 Forthcoming enhancements in the next version of the ANEM model

In relation to this project, one forthcoming enhancement to the ANEM model that could significantly inform knowledge relevant to this project relates to incorporating strategic considerations on the part of generators into the model. This enhancement could improve the modelling of the interactions between the proposed plant and NEM to inform better investment decisions.

The current version of the ANEM model assumes least cost dispatch whereby generators provide supply offers reflecting their true marginal costs without any strategic bidding. Strategic bidding on the part of generators is possible in the ANEM model using a reinforced learning algorithm that seeks to manipulate the intercept and slope of the marginal cost function of generators in order to maximize their profits. Typically, this is achieved by shifting the reported marginal cost curve above the true cost curve thereby ‘inflating’ marginal cost bids (and spot prices) while manipulating the slope can induce capacity manipulation in pursuit of higher profits.

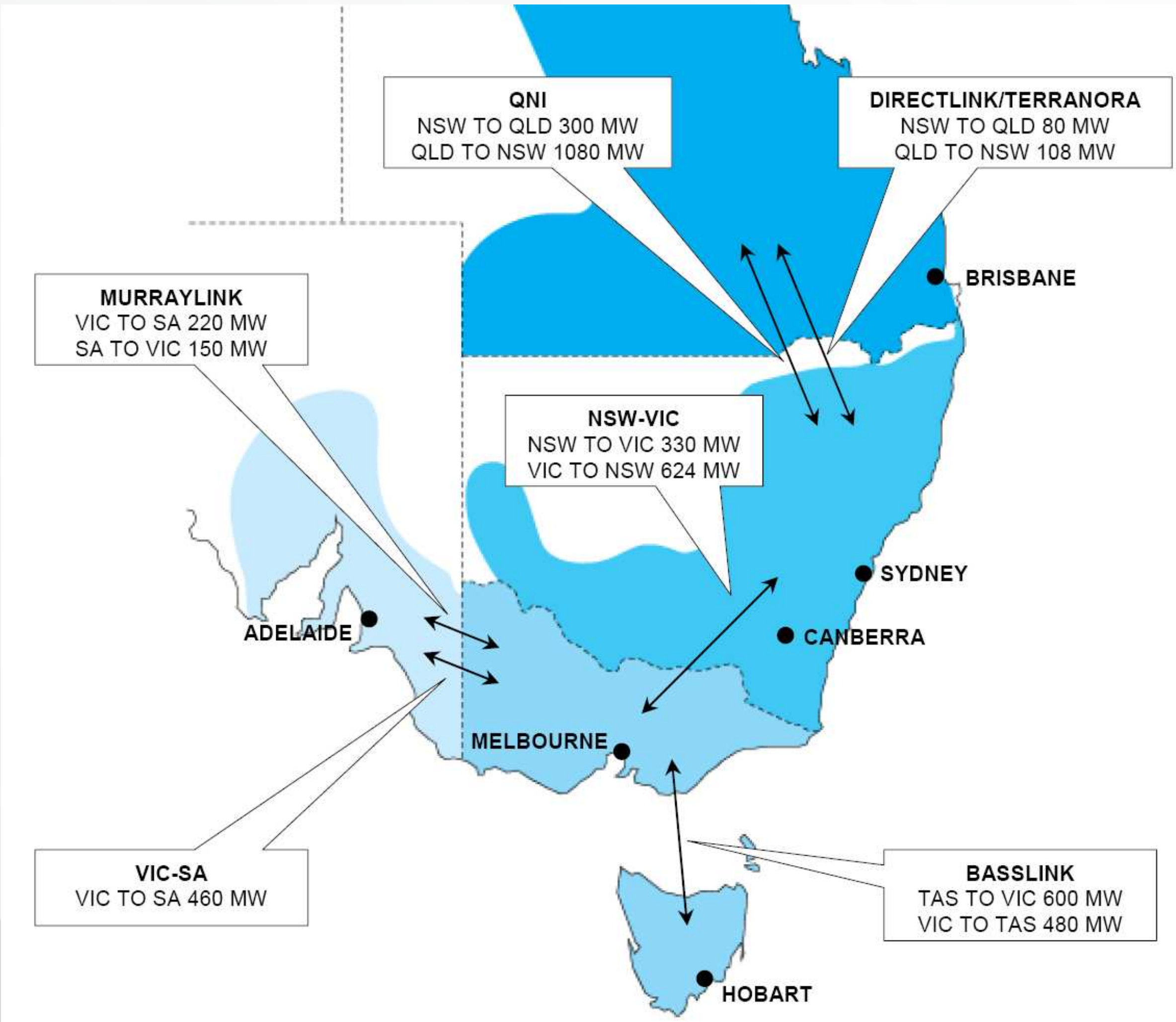
The least cost competitive equilibrium solution utilized in this report acts as the initial condition for strategic behaviour on the part of generators. However, model simulations utilizing strategic bidding are much more expensive in terms of CPU resources and operational time, affecting the number and type of simulations that can be potentially run.

The rationale for investigating strategic behaviour reflects the results identified in this report relating to temporary increases in average wholesale spot prices in Sections 5.2 and 5.4 that clearly demonstrate how the manipulation of capacity (especially its withdrawal) can increase average wholesale spot prices significantly, thereby altering the potential profit/loss position of generators.

8 Appendix A – Australian National Electricity Market Network

This appendix provides network diagrams of the nodes discussed in this report. We also know these nodes as load serving entities or demand regions. However, two of the nodes are supply only nodes without associated demand. Figure 18 shows the interconnectors between the states, which provides an overview of the more detailed state network diagrams in the following figures.

Figure 18: Interconnectors on the NEM



(Source: Tamblyn 2008, p. 7)

Regarding the numbering on the nodes, if the node number and demand region number are the same, we place just one number on the node. If the node number and demand region number differ, we place both numbers on the node in the following way: (node number, demand region number). For instance, (10, 11) is on the node at North Morton.

Node number 3 called 'North' attaches the proposed plant, that is, the Collinsville gas/solar thermal hybrid generator, to the NEM.

Figure 19: Stylised topology of QLD transmission lines and Load Serving Entities

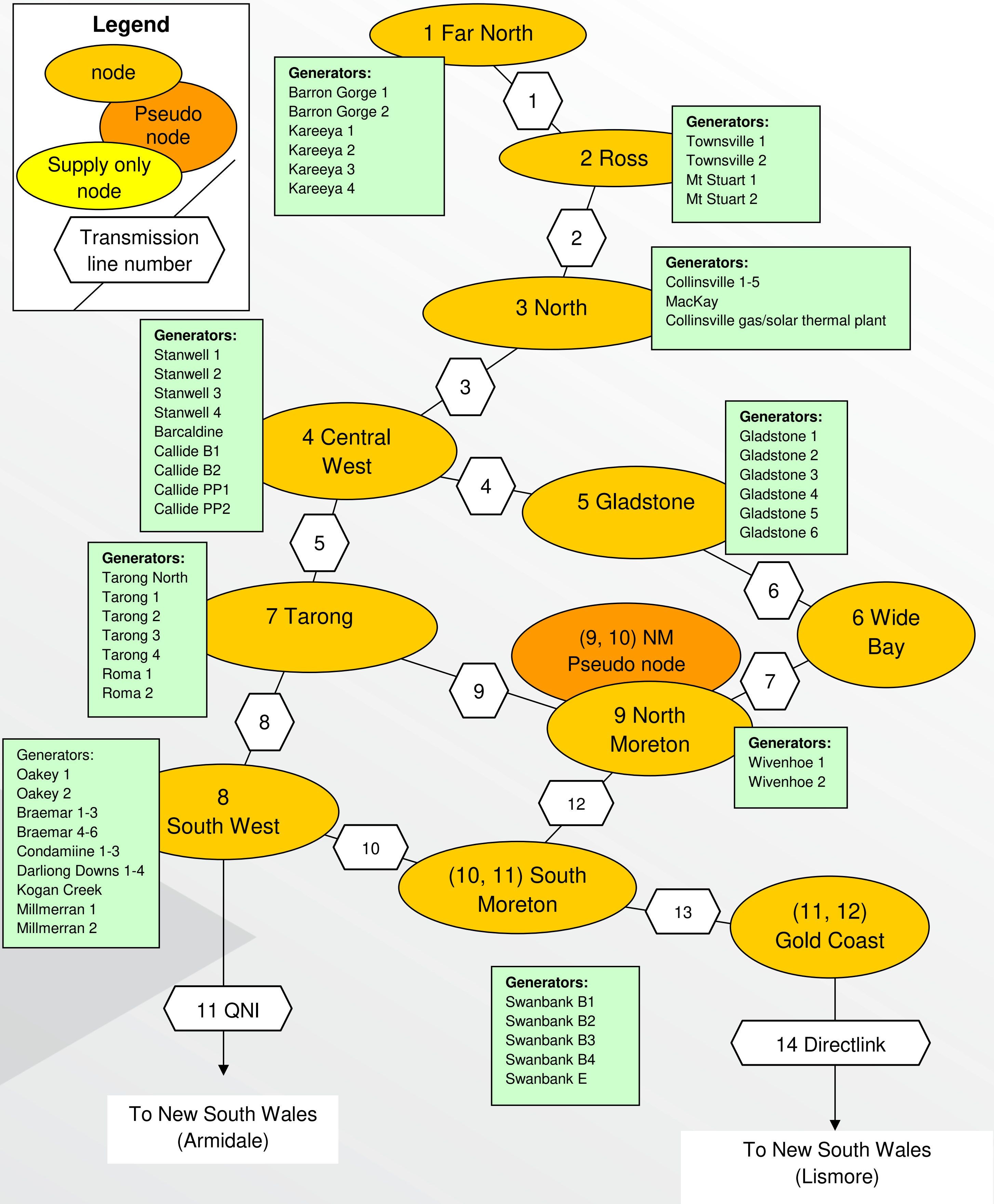


Figure 20: Stylised topology of NSW transmission lines and LSE

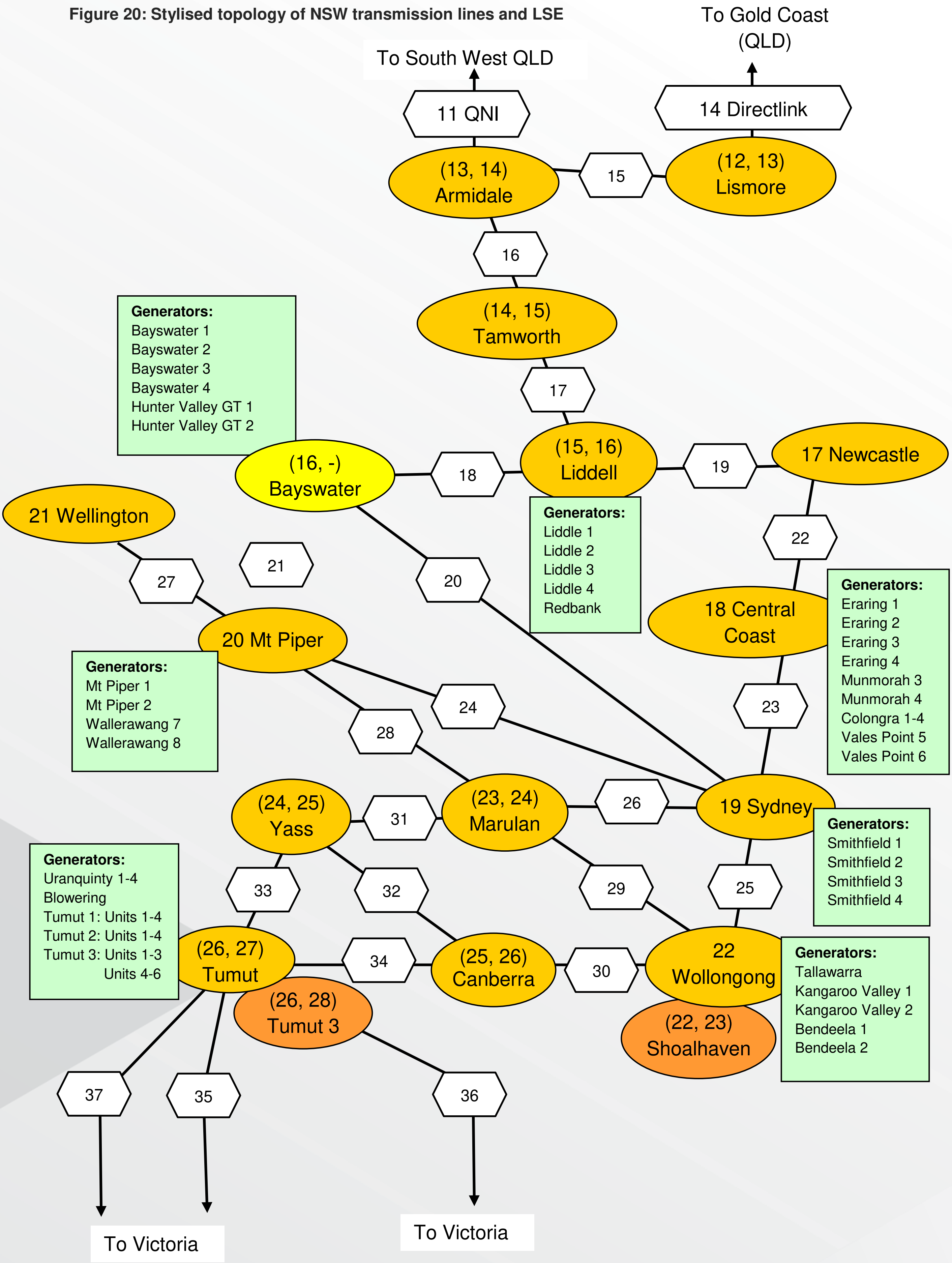


Figure 21: Stylised topology of VIC transmission lines and Load Serving Entities

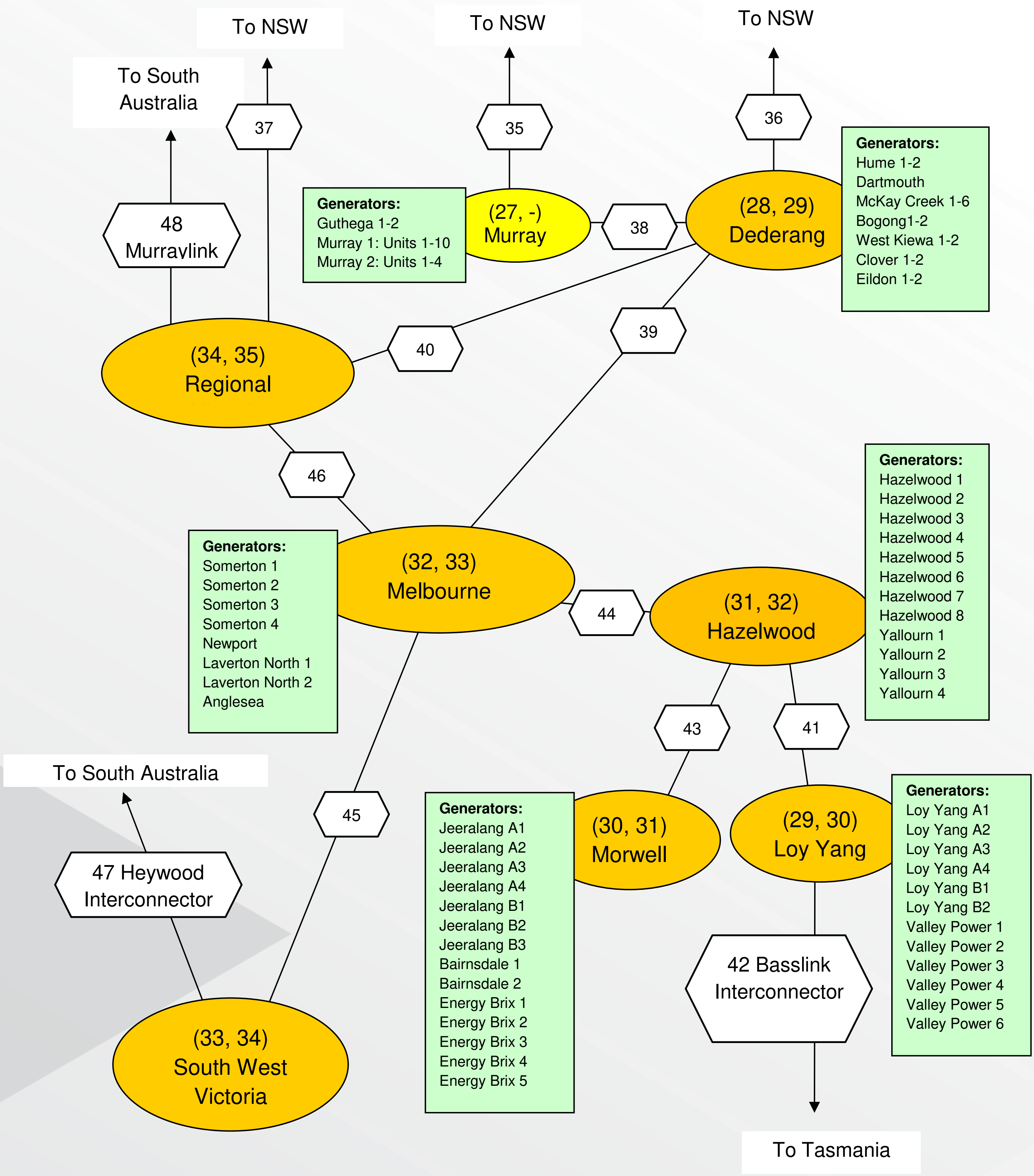


Figure 22: Stylised topology of SA transmission lines and Load Serving Entities

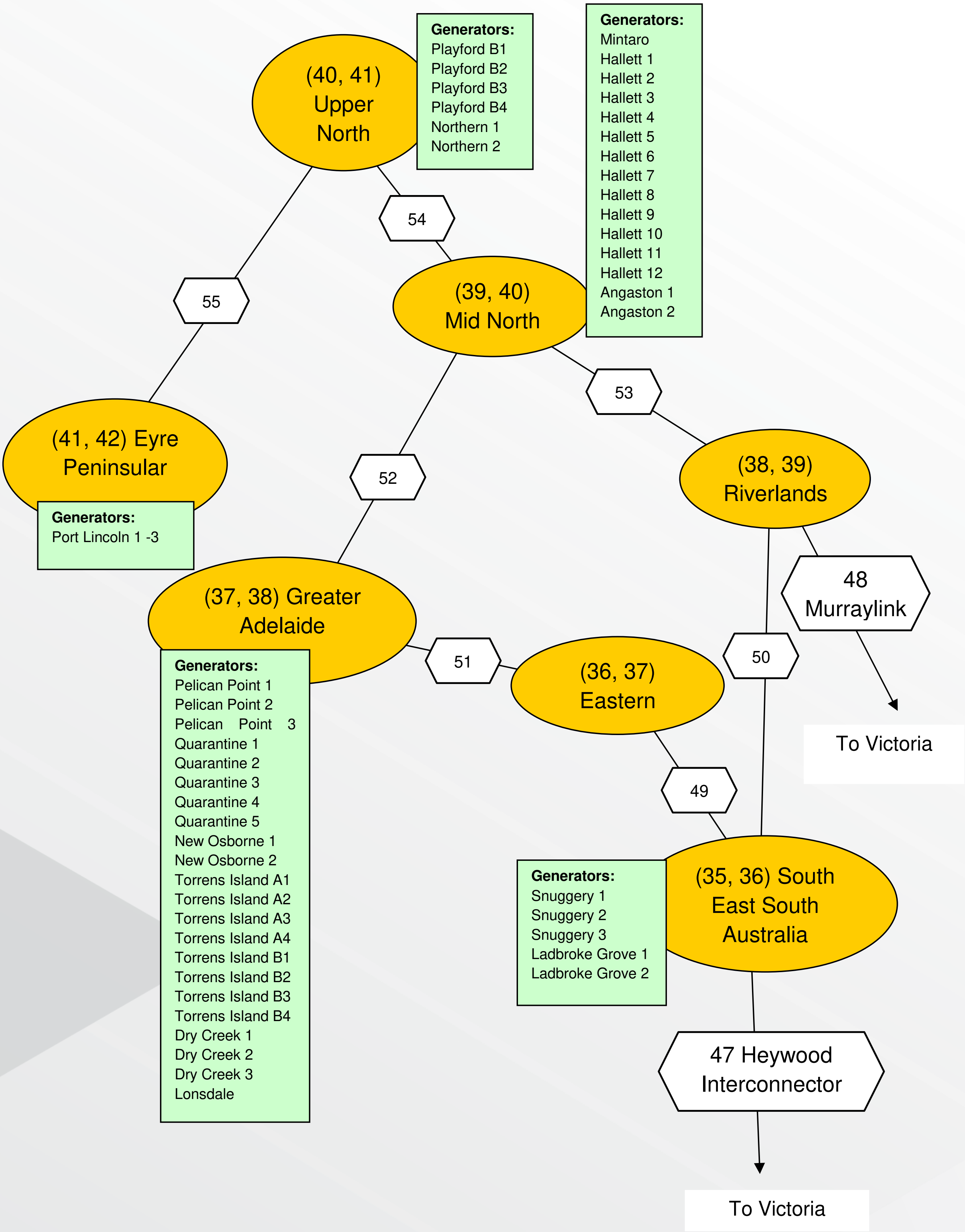
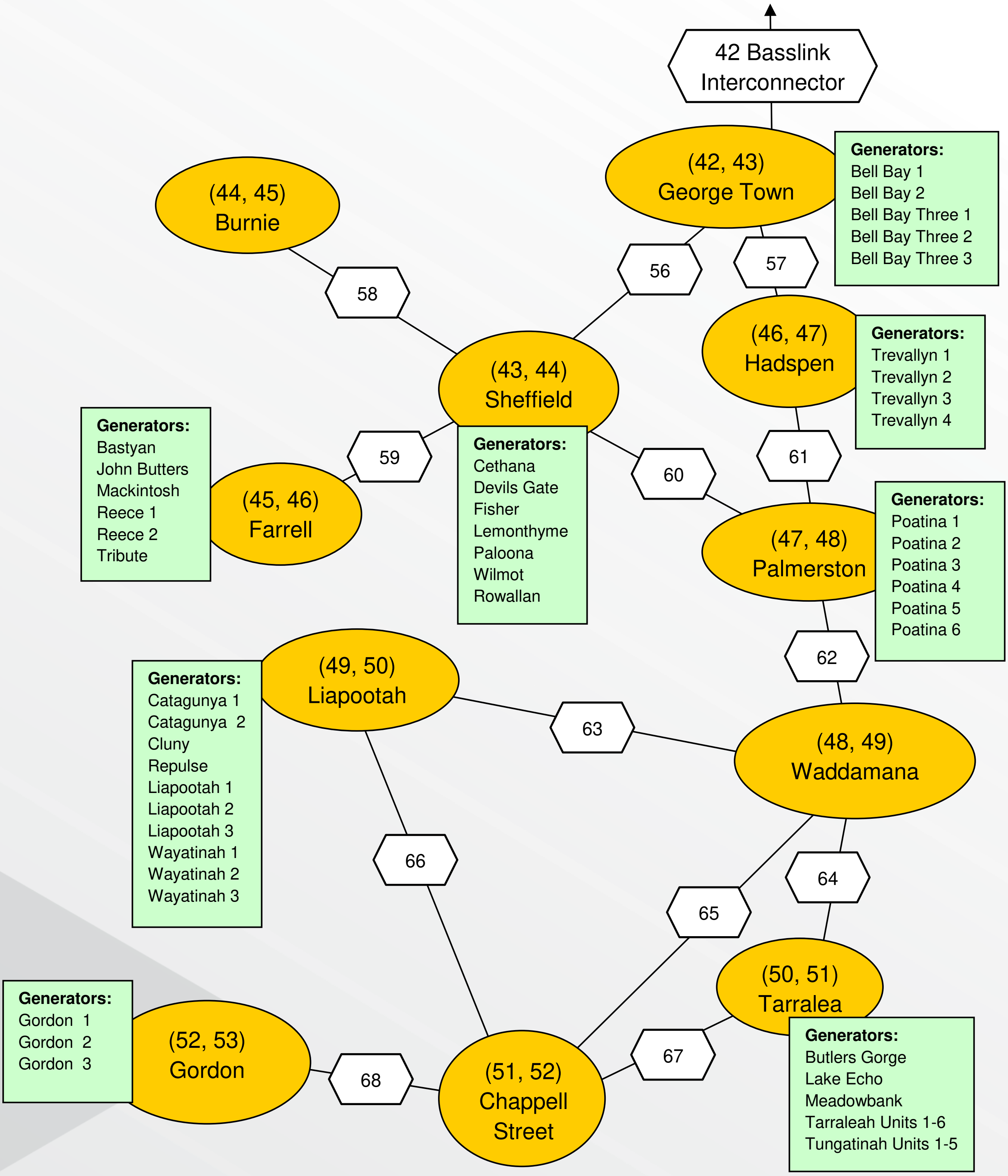


Figure 23: Stylised topology of TAS transmission lines and Load Serving Entities



9 Appendix B – Australian National Electricity Market Model

This appendix discusses the Australian National Electricity Market (ANEM) Model. This report uses the ANEM model to study the interactions between the NEM and the proposed plant at Collinsville to determine the wholesale spot price.

The ANEM model uses the node and transmission line topology in Appendix A. ANEM is an agent based model and the agents include demand and supply side participants as well as a network operator. The nodes and transmission lines shown in Appendix A constrain the behaviour of these agents. The following sections provide an outline of the ANEM model and present the principal features of the agents in the model. We discuss the ANEM's algorithm used to calculate generation production levels, wholesale prices and power flows on transmission lines. We also discuss practical implementation considerations.

9.1 Outline of the ANEM model

The methodology underpinning the ANEM model involves the operation of wholesale power markets by an Independent System Operator (ISO) using Locational Marginal Pricing (LMP) to price energy by the location of its injection into, or withdrawal from, the transmission grid. ANEM is a modified and extended version of the American *Agent-Based Modelling of Electricity Systems* (AMES) model developed by Sun and Tesfatsion (2007a, 2007b) and utilises the emerging powerful computational tools associated with Agent-based Computational Economics (ACE). This type of modelling uses a realistic representation of the network structure and high frequency behavioural interactions made possible by the availability of powerful computing resources. The important differences between the institutional structures of the Australian and USA wholesale electricity markets are also fully reflected in the modelling undertaken and outlined more fully in Wild, Bell and Foster (2012a, Sec. 1).

To understand the interaction between the proposed plant and the NEM requires a realistic model containing many of the salient features of the NEM. These features include realistic transmission network pathways, competitive dispatch of all generation technologies with price determination based upon variable cost and branch congestion characteristics and intra-regional and inter-state trade.

In the ANEM model, we use a Direct Current Optimal Power Flow (DC OPF) algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. This framework accommodates many of the features mentioned above including: intra-state and inter-state power flows; regional location of generators and load centres; demand bid information and the following unit commitment features:

- variable generation costs;
- thermal Megawatt (MW) limits (applied to both generators and transmission lines);
- generator ramping constraints;
- generator start-up costs; and
- generator minimum stable operating levels.

9.2 Principal features of the ANEM model

The ANEM model is programmed in Java using Repast (2014), a Java-based toolkit designed specifically for agent base modelling in the social sciences. The core elements of the model are:

- The wholesale power market includes an ISO and energy traders that include demand side agents called Load-Serving Entities (LSE's) and generators distributed across the nodes of the transmission grid.
- The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network.
- The ANEM wholesale power market operates using increments of one half-hour.
- The ANEM model ISO undertakes daily operation of the transmission grid within a single settlement system, which consists of a real time market settled using LMP.
- For each half-hour of the day, the ANEM model's ISO determines power commitments and LMP's for the spot market based on generators' supply offers and LSE's demand bids used to settle financially binding contracts.
- The inclusion of congestion components in the LMP helps price and manage transmission grid congestion.

9.2.1 Transmission grid characteristics in the ANEM model

The transmission grid utilised in the ANEM model is an AC grid modelled as a balanced three-phase network. In common with the design features outlined in Sun and Tesfatsion (2007a), we make the following additional assumptions:

- The reactance on each branch is assumed to be a total branch reactance, meaning that branch length has been taken into account in determining reactance values;
- All transformer phase angle shifts are assumed to be 0;
- All transformer tap ratios are assumed to be 1; and
- All line-charging capacitances are assumed to be 0.

To implement the DC OPF framework used in the ANEM model, two additional electrical concepts are required. These are base apparent power, which is measured in three-phase Megavoltamperes (MVA's), and base voltage, which is measured in line-to-line Kilovolts (kV's). We use these quantities to derive the conventional per unit (PU) normalisations used in the DC OPF solution and facilitate conversion between Standard International (SI) and PU unit conventions.

The ANEM model views the transmission grid as a commercial network consisting of pricing locations for the purchase and sale of electricity power. A pricing location is also a location at which market transactions are settled using publicly available LMP's and coincides with the set of transmission grid nodes.

Appendix A outlines the transmission grid in the ANEM model, which contains 68 branches and 52 nodes. It combines the Queensland (QLD), New South Wales (NSW), Victorian (VIC), South Australia (SA) and Tasmanian (TAS) state modules. The following interconnectors link the states:

- QNI (line 11) and Directlink (line 14) links Queensland and New South Wales;
- Tumut-Murray (line 35), Tumut-Dederang (line 36) and Tumut-Regional Victoria (line 37) link New South Wales and Victoria;
- Heywood (line 47) and Murraylink (line 48) link Victoria and South Australia; and
- Basslink (line 42) links Victoria and Tasmania.

The ANEM model uses the DC OPF framework. Therefore, ANEM models the High Voltage DC (HVDC) Interconnectors DirectLink, MurrayLink and BassLink as 'quasi AC' links determining power flows from reactance and thermal MW rating values.

The major power flow pathways in the model reflect the major transmission pathways associated with 275, 330, 500/330/220, 275 and 220 KV transmission branches in Queensland, New South Wales, Victoria, South Australia and Tasmania, respectively. Key transmission data required for the transmission grid in the model relate to an assumed base voltage value, base apparent power, branch connection and direction of flow information, maximum thermal rating of each transmission branch (in MW's) and an estimate of its reactance value (in ohms). Base apparent power is set to 100 MVA, an internationally recognized value. Thermal ratings of transmission lines was constructed from data contained in AEMO (2013c) using the detailed grid diagrams in AEMO (2013b) to identify transmission infrastructure relevant to the transmission grid structure used in the ANEM model. We obtained reactance and load flow data from AEMO on a confidential basis.

AEMO defines these values in terms of MVA. We convert these values to MWs assuming a power factor of unity. Therefore, ANEM's MW values correspond to the MVA values in the source AEMO data files. We also utilize information in the AEMO equipment ratings files to accommodate differences in maximum thermal ratings between summer and winter. Typically, the maximum MW thermal capacity rating of transmission lines is greater in winter than in summer because lower temperatures occur more often in winter then summer. Therefore, ANEM uses different thermal MW capacity values in summer and winter. We also assume that the alloy in the transmission lines' determines the reactance and reactance is unaffected by temperature. These assumptions permit the use of a constant value for reactance on each branch.

In Appendix A, we define the direction of flow on a transmission branch (e.g. line) connecting two nodes as 'positive' if the power flows from the lower numbered node to the higher numbered node. For example, for line 1 connecting Far North Queensland (node 1) and the Ross node (node 2), power flowing from Far North Queensland to Ross on line 1 would have a positive sign, while power flowing on line 1 from Ross to Far North Queensland would have a negative sign. The latter type of power flow is termed 'reverse' direction flow. In the ANEM model, it is possible to accommodate power flows in the positive and reverse direction having different thermal limits and different capacities for summer and winter.

9.2.2 Demand-side agents in the ANEM model: LSE's

A LSE is an electric utility that has an obligation to provide electrical power to end-use consumers (residential, commercial or industrial). The LSE agents purchase bulk power in the wholesale power market each day to service customer demand (called load) in the downstream retail market, thereby linking the wholesale power market and retail market. We assume that downstream retail demands serviced by the LSE's exhibit negligible price sensitivity, reducing to daily supplied load profiles which represents the real power demand (in MW's) that the LSE has to service in its downstream retail market for each half-hour of the day. LSE's are also modelled as passive entities who submit daily load profiles to the ISO without strategic considerations (Sun & Tesfatsion 2007b).

The revenue received by LSE's for servicing these load obligations are regulated to be a simple 'dollar mark-up' based retail tariff. For example, in Queensland, the state government regulates retail tariffs that are payable by most residential customers. Prior to July 2009, for example, this amounted to 14.4c/KWh exclusive of GST, which, in turn, translated into a retail tariff of $144/MWh. Thus, in the current set-up, we assume that LSE's have no incentive to submit price-sensitive demand bids into the market.

ANEM requires half-hourly regional load data. We derived this load data for Queensland and New South Wales using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state load totals published by AEMO (2014b) for the 'QLD1' and 'NSW1' markets. For the other three states, the regional shares were determined from terminal station load forecasts associated with summer peak demand (and winter peak demand, if available) contained in the annual planning reports published by the transmission companies Transend (Tasmania), Vencorp (Victoria) and ElectraNet (South Australia). These regional load shares were then interpolated to a monthly based time series using a cubic spline technique and these time series of monthly shares were then multiplied by the 'TAS1', 'VIC1' and 'SA1' state load time series published by AEMO (2014b) in order to derive the regional load profiles for Tasmania, Victoria and South Australia.

Additionally, the demand concept underpinning the state totals published by AEMO and used in the modelling is a net demand concept related conceptually to the output of scheduled and semi-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. This demand concept is termed 'scheduled demand' (AEMO 2012) – elsewhere termed "total" demand in this report. As such, this net demand concept can be viewed as being calculated from gross demand, after contributions from small scale solar PV and both small scale and large scale non-scheduled generation (including wind, hydro and bagasse generation) has been netted out to produce the net demand concept used in the modelling.

The actual demand concept employed in the modelling is a grossed up form of scheduled demand, which we obtained by adding the output of large-scale non-scheduled generation to the scheduled demand data, see Equation 1. We obtained the five-minute non-scheduled generation output data for the period 2007 to 2013 from AEMO and averaged across six five-minute intervals to obtain half-hourly output traces. We then summed across all non-scheduled generators located within a node and added to the nodal based scheduled demand to determine the nodal based augmented demand concept used in the modelling. Therefore, the demand concept employed in the modelling equates to the sum of the output of scheduled and semi-scheduled generation, non-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. It does not include the contributions from small scale solar PV and WTG and, as such, still represents a net demand concept.

9.2.3 Supply-side agents in the ANEM model: generators

We assume that generators produce and sell electrical power in bulk at the wholesale level. Each generator agent is configured with a production technology with assumed attributes relating to feasible production interval, total cost function, total variable cost function, fixed costs [pro-rated to a dollar per hour basis] and a marginal cost function. Depending upon plant type, a generator may also have start-up costs. Each generator also faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased over the next half-hour within the half hourly dispatch horizon. Production levels determined from the ramp-up and ramp-down constraints must fall within the minimum and maximum thermal MW capacity limits confronting each generator.

The MW production and ramping constraints are defined in terms of ‘energy sent out’ – i.e. the energy available to service demand. In contrast, variable costs and carbon emissions are calculated from the ‘energy generated’ production concept which is defined to include energy sent out plus a typically small amount of additional energy that is produced internally as part of the power production process. ANEM models the variable costs of each generator as a quadratic function of half-hourly real energy produced by each generator. The marginal cost function is calculated as the partial derivative of the quadratic variable cost function with respect to hourly energy produced, producing a marginal cost function, that is, linear (upward sloping) in real energy production of each generator (Sun & Tesfatsion 2007b).

The variable cost concept underpinning each generator’s variable cost incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. The fuel, VO&M and carbon emissions/cost parameterisation was determined using data published in ACIL Tasman (2009) for thermal plant and from information sourced from hydro generation companies for hydro generation units. Wild, Bell and Foster (2012a, App. A) provide a formal derivation of the various cost components in detail.

Additionally, we averaged the 2014-20 gas prices from a gas pricing model called ATESHGAH (Wagner 2004; Wagner, Molyneaux & Foster 2014) to provide this report’s 2014 gas prices for both the reference and high gas price research questions. Both this report’s 2014 gas prices and ANEM assume an inflation rate of 2.5 per cent per annum indexed on year 2014.

9.2.4 Passive hedging strategy incorporated in the ANEM model

Both theory and observation suggest that financial settlements based on market structures similar to that implemented in the NEM expose market participants to the possibility of extreme volatility in spot prices encompassing price spike behaviour (typically of short duration) or sustained periods of low spot prices. These impacts pose significant danger to the bottom line of both LSE’s and generators respectively, requiring both types of agents to have long hedge cover positions to protect their financial viability.

In the ANEM model, a key decision for both types of agents is when to activate long cover to protect their bottom lines from the consequences of consistently high (low) spot prices – key determinants of ‘excessively’ high costs (‘excessively’ low revenues) faced by LSE’s and generators, respectively. Failure to do so could pose serious problems for the continued financial solvency of market participants. The form of protection adopted in the model is a ‘collar’ instrument between LSE’s and generators, which ANEM activates whenever spot prices rise above a ceiling price (for LSE’s) or falls below a price floor (for generators). If the price floor applicable to generators is set equal to the generators long run marginal cost, ANEM can implement a generator long run revenue recovery through the hedge instrument.

ANEM assumes that both LSE's and generators pay a small fee (per MWh of energy demanded or supplied) for this long hedge cover. This fee is payable irrespective of whether long cover is actually activated. Thus, the small fee acts like a conventional premium payment in real options theory. If the spot price is greater than the price floor applicable to generator long cover and below the price ceiling applicable for LSE long cover, than no long cover is activated by either type of agent although the fee payable for the long cover is still paid by both types of agents.

9.3 DC OPF solution algorithm used in the ANEM model

Optimal dispatch, wholesale prices and power flows on transmission lines are determined in the ANEM model by a DC OPF algorithm. The DC OPF algorithm utilised in the model is that developed in Sun and Tesfatsion (2007a) and involves representing the standard DC OPF problem as an augmented strictly convex quadratic programming (SCQP) problem, involving the minimization of a positive definite quadratic form subject to linear equality and inequality constraints. The augmentation entails utilising an objective function that contains quadratic and linear variable cost coefficients and branch connection and bus admittance coefficients. The solution values are the real power injections and branch flows associated with the energy production levels for each generator and voltage angles for each node.

We use the Mosek (2014) optimisation software that exploits direct sparse matrix methods and utilises a convex quadratic programming algorithm based on the interior point algorithm to solve the DC OPF problem. Equation 24 shows ANEM's implementation of the Mosek DC OPF algorithm inequality constraints.

The ANEM model solves the following optimisation for every half-hour. Equation 24(a) shows the objective function that minimises real-power production levels P_{Gi} for all generators $i = 1,...,I$ and voltage angles δ_k for all transmission lines and $k = 2,..,K$ subject to the constraints in Equation 24(b), (c) and (d).

Equation 24: ANEM's objective function and constraints

(a) Objective function: Minimise generator-reported total variable cost and nodal angle differences

$$\sum_{i=1}^{I}\left[A_i P_{G_i} + B_i P_{G_i}^2\right] + \pi\left[\sum_{I_m \in BR}\delta_m^2 + \sum_{km\in BR,\, k\geq 2}[\delta_k - \delta_m]^2\right],$$

Where:

i = generator number
P_{Gi} = real power (MW) production level of generator i
k = transmission line number
δ_k = phase angle for transmission line k

(b) Constraint 1: Nodal real power balance equality constraint

$$0 = PLoad_k - PGen_k + PNetInject_k$$

Where:

$PLoad_k = \sum_{j \in J_k} P_{L_j}$ (E.g. aggregate power take-off at node k, e.g. demand)

$PGen_k = \sum_{i \in I_k} P_{G_i}$ (E.g. aggregate power injection at node k, e.g. generation)

$PNetInject_k = \sum_{km \text{ or } mk \in BR} F_{km}$

$F_{km} = B_{km}\left[\delta_k - \delta_m\right]$

(E.g. real power flows on branches connecting nodes 'k' and 'm')

$k = 1, \ldots, K$

$\delta_1 \equiv 0$

(c) Constraint 2: Transmission line real power thermal inequality constraints

$F_{km} \geq -F_{km}^{UR}$, (lower bound constraint: reverse direction MW branch flow limit)

$F_{km} \leq F_{km}^{UN}$, (upper bound constraint: normal direction MW branch flow limit)

Where:

$km \in BR$

$k = 1, \ldots, K$

$\delta_1 \equiv 0$

(d) Constraint 3: Generator real-power production inequality constraints

$P_{G_i} \geq P_{G_i}^{LR}$, (lower bound constraint: lower half-hourly MW thermal ramping limit)

$P_{G_i} \leq P_{G_i}^{UR}$ (upper bound constraint: upper half-hourly MW thermal ramping limit),

Where:

$P_{G_i}^{LR} \geq P_{G_i}^{L}$,

(lower half-hourly thermal ramping limit ≥ lower thermal MW capacity limit)

$P_{G_i}^{UR} \leq P_{G_i}^{U}$

(upper half-hourly thermal ramping limit ≤ upper thermal MW capacity limit)

$i = 1, \ldots, I$

Upper limit U and lower limit L, A_i and B_i are linear and quadratic cost coefficients from the variable cost function. δ_k and δ_1 are the voltage angles at nodes '*k*' and '*m*' (measured in radians). Parameter π is a positive soft penalty weight on the sum of squared voltage angle differences. Variables $F^{UN}{}_{km}$ and $F^{UR}{}_{km}$ are the (positive) MW thermal limits associated with real power flows in the 'normal' and 'reverse' direction on each connected transmission branch $km \in BR$.

The linear equality constraint refers to a nodal balance condition, which requires that, at each node, power take-off (by LSE's located at that node) equals power injection (by generators located at that node) and net power transfers from other nodes on 'connected' transmission branches. On a node-by-node basis, the shadow price associated with this constraint gives the LMP (i.e. regional wholesale spot price) associated with that node. The linear inequality constraints ensure that real power transfers on connected transmission branches remain within permitted 'normal' and 'reverse' direction thermal limits and the real power produced by each generator remains within permitted lower and upper thermal MW capacity limits while also meeting MW ramp up and ramp down generator production limits.

The ANEM model differs in significant ways from many of the wholesale electricity market models used to investigate the Australian electricity industry. First, ANEM has a more disaggregated nodal structure than many of the other wholesale market models. The ANEM model contains 52 nodes and 68 transmission branches, including eight inter-state interconnectors and 60 intra-state transmission branches as depicted in Appendix A. In contrast, other wholesale market models often involve five or six nodes, corresponding to each state region in the NEM, and six or seven inter-state interconnectors. For instance, see McLennan Magasanik Associates (MMA 2006), ROAM Consulting (ROAM 2008, App. A, p. II), Sinclair Knight Merz (SKM & MMA 2011, p. 62) and ACIL Tasman (2011, Sec. B.2). The number of nodes in these models depends upon the treatment of Snowy Mountains Region in the NEM.

Second, the solution algorithm used in the ANEM model is very different conceptually from the linear programming algorithms used in many of the other wholesale market models. ANEM uses quadratic programming to minimise both nodal angle differences and generator variable costs subject to network limits on transmission branches and generation. Optimal power flows on transmission branches are determined from optimised nodal angle differences, which, in turn, depend on transmission branch adjacency and bus admittance properties determined from the transmission grid's structure and branch reactance data (Sun & Tesfatsion 2007a, Sec. 4). Accounting for power flows in the equality constraints of the DC OPF algorithm allows the incorporation of congestion components in regional wholesale spot prices, which can produce divergence in regional spot prices associated with congestion on intra-state transmission branches.

In contrast, the linear programming algorithms do not explicitly optimise power flows as part of the optimisation process, directly capture the impact of branch congestion on spot prices or account for any impact associated with congestion on intra-state transmission branches. Moreover, these models typically fail to offer intra-state regional spot prices.

9.4 Practical implementation considerations

The solution algorithm employed in all simulations involves applying the 'competitive equilibrium' solution. This means that all generators submit their true marginal cost coefficients without strategic bidding. This permits assessment of the true cost of generation and dispatch. Therefore, the methodological approach underpinning modelling is to produce 'as if' scenarios. In particular, we do not try to emulate actual historical generator bidding patterns or strategic bidding based upon monopolistic competition or game theoretic approaches. Instead, our objective is to investigate, in an ideal setting, how the proposed plant at Collinsville would interact with the NEM, from the perspective of least-cost dispatch.

As such, the analytic framework is a conventional DC OPF analysis with generator supply offers based upon Short Run Marginal Cost (SRMC) coefficients.

We also assume that all thermal generators are available to supply power during the whole period under investigation, excepting assumed refurbishment or replacement programmes, plant retirements or temporary plant closures to be specified below. This rules out the possibility where allowing for unscheduled outages in thermal generators would be expected to increase costs and prices above what is produced when all relevant thermal plant is assumed to be available to supply power because it acts to constrain the least cost supply response available to meet prevailing demand.

In order to make the model response to the various scenarios more realistic, we have taken account of the fact that baseload and intermediate coal and gas plant typically have 'non-zero' must run MW capacity levels termed minimum stable operating levels. These plants cannot run below these specified MW capacity levels without endangering the long-term productive and operational viability of the plant itself or violating statutory limitations relating to the production of pollutants and other toxic substances.

Because of the significant run-up time needed to go from start-up to a position where coal-fired power stations can actually begin supplying power to the grid, all coal plant was assumed to be synchronized with the grid so they can supply power. Thus, their minimum stable operating limits were assumed to be applicable for the whole period being investigated for which they are operational and they do not face start-up costs. Gas plant, however, has very quick start-up characteristics and can be synchronized with the grid and be ready to supply power typically within a half hour period of the decision to start-up. Therefore, in this case, the start-up decision and fixed start-up costs can accrue within the dispatch period being investigated.

Two approaches to modelling gas plant were adopted depending upon whether the gas plant could reasonably be expected to meet base-load and intermediate production duties or just peak-load production duties. If the gas plant was capable of meeting base-load or intermediate production duties, the plant was assigned a non-zero minimum stable operating capacity. In contrast, peak-load gas plant was assumed to have a zero minimum stable operating capacity. It should be recognised that because of the high domestic gas prices associated with both the reference and high gas price scenarios when compared with historically low domestic gas prices means that all OCGT gas plant are modelled as peak-load plant. On the other hand, gas thermal and Combined Cycle Gas Turbine (CCGT) plant are generally modelled as baseload or intermediate gas plant. In the former case, they are assumed to offer to supply power for a complete 24-hour period – thus, the minimum stable operating capacity is applicable for the whole 24-hour period and these plants do not face start-up costs. In contrast, some gas thermal plant is assumed to fulfil intermediate production duties and only offer to supply power during the day. In this case, the minimum stable operating capacities were only applicable for those particular half-hours of the day and these plants face the payment of fixed start-up costs upon start-up.

Details of the minimum stable operating capacities assumed for operational coal and base-load and intermediate gas-fired plant are listed in Table 37 and Table 38, together with details about their assumed operating time, whether start-up costs were liable and, if so, what values were assumed for these particular costs.

Table 37: Minimum stable operating capacity limits for coal plant, assumed operating time and start-up cost status

Generation Plant	Minimum Stable Operating Capacity Level % of total MW Capacity (sent out basis)	Assumed Operating Time Hours	Start-up Status/Cost Yes/No	Assumed Start-up Cost $/MW per start
Black Coal – QLD				
Stanwell	40.00	24	No	$ 80.00
Callide B	40.00	24	No	$ 80.00
Callide C	40.00	24	No	$ 80.00
Gladstone	31.00	24	No	$ 90.00
Tarong North	40.00	24	No	$ 70.00
Tarong	40.00	24	No	$ 80.00
Kogan Creek	40.00	24	No	$ 40.00
Millmerran	40.00	24	No	$ 70.00
Black Coal – NSW				
Liddle	40.00	24	No	$ 50.00
Redbank	40.00	24	No	$150.00
Bayswater	40.00	24	No	$ 45.00
Eraring	40.00	24	No	$ 45.00
Vales Point	40.00	24	No	$ 45.00
Mt Piper	40.00	24	No	$ 45.00
Black Coal – SA				
Northern	55.00	24	No	$ 90.00
Brown Coal – VIC				
Loy Yang A	60.00	24	No	$ 50.00
Loy Yang B	60.00	24	No	$ 50.00
Hazelwood	60.00	24	No	$ 95.00
Yallourn	60.00	24	No	$ 80.00
Anglesea	60.00	24	No	$150.00

Table 38: Minimum stable operating capacity limits for baseload and intermediate gas plant, assumed operating time and start-up cost status

Generation Plant	Minimum Stable Operating Capacity Level % of total MW Capacity (sent out basis)	Assumed Operating Time Hours	Start-up Status/Cost Yes/No	Assumed Start-up Cost $/MW per start
QLD				
Townsville	50.00	24	No	$100.00
Condamine	50.00	24	No	$50.00
Darling Downs	50.00	24	No	$50.00
Swanbank E	50.00	24	No	$ 50.00
NSW				
Smithfield	60.00	24	No	$100.00
Tallawarra	50.00	24	No	$ 40.00
VIC				
Newport	65.00	13 daytime only	Yes	$ 40.00
SA				
Pelican Point	50.00	24	No	$ 70.00
New Osborne	76.00	24	No	$ 80.00
Torrens Is. A	50.00	13 daytime only	Yes	$ 80.00
Torrens Is. B	50.00	24	No	$ 65.00

Recent commissioning and de-commissioning of thermal generation plant has been accommodated in the modelling. Specifically, commissioned plant includes:

- Condamine, unit 3 in 2010-11;
- Darling Downs, all units in 2010-11;
- Yarwun in 2010-11; and
- Mortlake, all units in 2011-12.

We assumed the following generation de-commissioned:

- Swanbank B:
  - two units in 2010-11;
  - one unit in 2011-12;
  - last unit in 2012-13;
- Collinsville, all units in 2012-13;
- Munmorah, all units in 2012-13;
- Energy Brix, units 3-5 in 2012-13;
- Energy Brix, units 1-2 in 2013-14;
- Playford B, all units in 2012-13;
- Wallerawang C, all units from 2014;
- MacKay Gas Turbine from 2017;
- Mt Stuart from 2023; and
- Anglesea from 2025.

While we have accommodated the permanent plant closures listed above (including Playford B, which we have assumed will not be operated again because of its age), we have also included some recently announced temporary plant closures associated with:

- Tarong, units 3 and 4 in 2012-13, with one unit coming back into service in 2014 and the other in 2015;

- Swanbank E, in 2014-2016 with the unit coming back online at the start of 2017; and
- Northern, one unit offline during the winter of 2014 and then assumed to operate as normal

More generally, we have implemented the plant outages listed in (AEMO 2014g) as at May 2014 for Hydro Tasmania and Snowy Mountains Hydro in the modelling over the interval 2014 to 2024.

For the interval 2025 to 2047, two particular 'states-of-play' were adopted in the modelling, depending upon whether the reference or high gas price scenarios were adopted for the modelling of gas generation. In the case of the reference gas price scenario, two further states-of-play were adopted relating to the treatment of coal generation plant. In the first case, the first state-of-play involved a refurbishment program for older coal-fired generators, implemented when they reached an operational lifetime of 50 years. The rationale for this programme is that concern over climate change has not become persuasive within society and coal-fired generation was assumed to remain a central component of the generation fleet, continuing the current Business-As-Usual (BAU) pathway. This programme involved assuming that one turbine per year of each respective coal-fired power station was taken off-line for refurbishment purposes before beginning operation over the remainder of the interval under investigation. Specifically, the following plant refurbishments were assumed to occur:

- Gladstone: 2025 to 2030;
- Liddell: 2025 to 2028;
- Hazelwood: 2025 to 2032;
- Vales Point: 2028 to 2030;
- Eraring: 2032 to 2035;
- Yallourn: 2032 to 2035;
- Tarong: 2036 to 2039;
- Bayswater: 2036 to 2039
- Loy Yang A: 2036 to 2039;
- Callide B: 2037 to 2038; and
- Loy Yang B: 2040 to 2041.

Note that this coal plant refurbishment programme was also implemented in the high gas price scenario.

The second state-of-play adopted under the reference gas price scenario entailed replacing older coal-fired power stations with lower carbon emissions intensive CCGT plant that was, however, capable of continuing the base-load production duties of the retiring coal plant. The rationale for this particular programme is that concern over climate change has become persuasive within society prompting policy-makers and Government to implement a policy of replacing the more carbon emission intensive coal-fired power stations once they reach the end of use date with lower carbon emission intensive CCGT plant. In this environment, notwithstanding the higher gas prices, CCGT plant is used as a bridging technology within the context of a diminishing carbon budget over the interval of investigation.

The basic structure of the CCGT plant was calculated by assuming that the Steam Turbine component was 63.13 per cent of the capacity of the OCGT component of the combined cycle plant. In calculating the capacity, the basic OCGT unit assumed in calculations was a 168 MW OCGT gas turbine which has been used in the NEM, for example, in Braemar 1 Power Station. This replacement programme was also assumed to be implemented when the coal-fired power stations reached a 50 year operational lifespan and involved the following replacement programme (with the year indicating when the replacement occurred):

- Gladstone: 2025 - [six 274.1 MW turbines (168 MW OCGT / 106.1 MW Steam Turbine (ST) per turbine)];
- Liddell: 2025 - [four 548.1 MW turbines (2x168 MW OCGT / 212.1 MW ST per turbine)];
- Hazelwood: 2025 - [six x 168 MW OCGT / two x 318.2 MW ST];
- Vales Point: 2028 - [one x 822.2 MW turbine (3x168 MW OCGT / 318.2 MW ST) and one x 548.1 MW turbine (2x168 MW OCGT / 212.1 MW ST)];
- Eraring: 2032 - [two x 822.2 MW turbines (3x168 MW OCGT / 318.2 MW ST per turbine) and two x 548.1 MW turbines (2x168 MW OCGT / 212.1 MW ST per turbine)];
- Yallourn: 2032 - [one x 548.1 MW turbine (2x168 MW OCGT / 212.1 MW ST) and three x 274.1 MW turbines (1x168 MW OCGT / 106.1 MW ST per turbine)];
- Tarong: 2036 - [one x 548.1 MW turbine (2x168 MW OCGT / 212.1 MW ST) and three x 274.1 MW turbines (1x168 MW OCGT / 106.1 MW ST per turbine)];
- Bayswater: 2036 - [four x 548.1 MW turbine (2x168 MW OCGT / 212.1 MW ST per turbine)];
- Loy Yang A: 2036 - [four x 548.1 MW turbine (2x168 MW OCGT / 212.1 MW ST per turbine)];
- Callide B: 2037 - [one x 548.1 MW turbine (2x168 MW OCGT / 212.1 MW ST) and one 274.1 MW turbines (1x168 MW OCGT / 106.1 MW ST)]; and
- Loy Yang B: 2040 - [two x 548.1 MW turbine (2x168 MW OCGT / 212.1 MW ST per turbine)];

Recall that in all scenarios, all OCGT plant is assumed to operate as peak-load plant and, as such, does not have any specified non-zero minimum stable operating levels or must run production configurations. Differences however emerge in the treatment of gas thermal generation between the reference and high gas price scenarios. In the case of the high gas price scenario, all gas thermal generation is assumed to be peak-load, and does not have any minimum stable operating level or must run production configuration. In contrast, for the reference gas price scenario, gas thermal generation is treated as base-load generation operating with both non-zero minimum stable operating levels and must run production configurations defined in Table 38. However, in summer one unit of Torrens Island A and B are not run as base-load plant, but instead, as peak-load plant with a zero minimum stable operating level and no must run production configuration. Furthermore, given the lower demand typically prevailing in winter, together with higher output from wind generation in especially South Australia and Victoria, both Newport, Torrens Island A and one unit of Torrens Island B are no longer run as base-load plant but, instead, as peak-load plant. It should also be noted that Tamar Valley CCGT plant is also operated in this mode during winter under both gas price scenarios. Finally, in the case of the high gas price scenario, the steam turbine component of New Osborne CCGT power station is also operated as a peak-load generation plant.

Apart from the replacement programme mentioned above, we have broadly fixed the generation structure used in simulations to the structure listed in Appendix A (after accounting for the plant de-commissioning mentioned above). In particular, we did not attempt to include any future proposed projects in the analysis because there is currently too much uncertainty over both the status and timing of many proposed projects.

This uncertainty principally reflects three factors. The first relates to financial uncertainty over future gas prices once the eastern seaboard CSG/LNG projects begin to operate from 2014-15. The second factor relates to the fall in average demand experienced widely throughout the NEM over the last couple of years, which affects the viability of baseload generation proposals as well as the future commissioning date of new project proposals. Specifically, the August 2014 Electricity Statement of Opportunities (AEMO 2014c) medium reserve deficit projection is zero until 2023-24 for all states. This implies an oversupply of generation capacity to meet demand, requiring no investment in new thermal plant until at least 2023-24. The third source of uncertainty is regulatory and political uncertainty about the future of carbon pricing and policy support for renewable energy. Therefore, given the generation set available for the ANEM model simulations, our modelling focuses on the interaction of the Collinsville plant with NEM, in particular the wholesale spot price. Moreover, the replacement programme mentioned above also seeks to replace aging coal-fired power stations with CCGT plant of roughly the same MW capacity and at the same nodal location.

ANEM assumes all thermal generators available to supply power, subject to the refurbishment/replacement programmes outlined above, but imposes restrictions on the availability of hydro generation units. The dispatch of thermal plant is optimised around the assumed availability patterns for the hydro generation units. In determining the availability patterns for hydro plant, we assumed that water supply for hydro plant was not an issue. If water supply issues or hydro unit availability were constraining factors, as was actually the case in 2007, for example, this would increase the cost and prices obtained from simulations because the cost of supply offers of hydro plant would be expected to increase significantly.

Because of the prominence of hydro generation in Tasmania, some hydro units were assumed to offer capacity over the whole year with account being taken of the ability of hydro plant to meet base-load, intermediate or peak-load production duties. For pump-storage hydro units such as Wivenhoe and Shoalhaven, the pump mode was activated by setting up a pseudo LSE located at the Morton North and Wollongong nodes – see Section 8 for further details. The combined load requirements for pump actions of all Wivenhoe and Shoalhaven hydro units were combined into a single load block determined by the model from unit dispatch records of these generators from the previous day and placed in the relevant pseudo LSE's. In both cases, the pump actions are assumed to occur in off-peak periods when the price (cost to hydro units) of electricity is lowest.

For all hydro plant, hydro generator supply offers were based on Long Run Marginal Cost (LRMC) coefficients. These coefficients take into account the need to meet fixed costs including capital and operational expenses and are often significantly larger in magnitude than corresponding SRMC coefficients. For mainland hydro plant, supply was tailored to peak load production. Thus, LRMC estimates were obtained for much lower annual capacity factors (ACF) than would be associated with hydro plant fulfilling base load or intermediate production duties, thus producing higher LRMC coefficients. Moreover, the ACF was reduced for each successive hydro turbine making up a hydro plant resulting in an escalating series of marginal cost coefficient bids for each successive turbine. In general, the lowest marginal cost coefficient shadowed peak-load OCGT plant while other turbines supply offers could be significantly in excess of cost coefficients associated with more expensive peak-load gas or diesel plant. This approach essentially priced the social cost of water usage within successive turbines of a hydro power station as an increasingly scarce commodity.

A key consideration governing the decision to use LRMC coefficients to underpin the supply offers of hydro generation plant is the predominance of such generators in Tasmania. With the absence of other major forms of thermal based generation in Tasmania and limited native load demand and export capability into Victoria, it is likely that nodal pricing, based on SRMC would not be sufficient to cover operational and capital costs. Supply offers based on LRMC, however, ensure that average price levels are sufficient to cover these costs over the lifetime of a hydro plant's operation. We also assumed that the minimum stable operating capacity for all hydro plant is zero and that no start-up costs are incurred when the hydro plants begin supplying power to the grid. Hydro plant is also assumed to have a very fast ramping capability.

Non-scheduled and semi-scheduled WTG are also included in the modelling, incorporating thirteen non-scheduled and fourteen semi-scheduled wind farms with a combined capacity of 2639.9 MW, which represents 97.0 per cent of total installed capacity of operational wind farms in the NEM at the end of 2013. Wind farms are assumed to construct supply offers for their output based upon their variable costs. As such, they are assumed to operate essentially as semi-scheduled plant. We assume that 85 per cent of total operating costs of wind farms are fixed costs whilst the remaining 15 per cent are variable costs. In general, the ($/MWh) supply offers of wind farms used in the modelling was in the range of $3.39/MWh to $4.69/MWh, and are amongst the cheapest forms of generation incorporated in the modelling.

Both non-scheduled and semi-scheduled wind generation operational over 2013 was incorporated in the modelling. However, the output of the wind farms in the modelling are incorporated as aggregated nodal wide entities calculated by summing the output of all non-scheduled and semi-scheduled wind farms located within a particular node. Moreover, we are restricting attention to those nodes that contain operating wind farms.

The default setting adopted for modelling purposes is for wind generation not to be dispatched with supply offers set to the Value-of-Lost-Load (VOLL) which is set to $10000/MWh. This default setting is overridden when the output of the nodal based wind generation source exceeds 10MW with supply offers then being based on SRMC coefficients.

In the ANEM model simulations performed for this project, we have also adopted an 'n' transmission configuration scenario. This approach involves applying the MW thermal limits determined from the sum of all individual transmission line thermal ratings in the group of transmission lines connecting two nodes. This approach effectively assumes no line outages occur and that the transmission lines are all in good working condition. For example, the capacity of each line is unconstrained below its rated capacity when all other transmission lines are operating at their maximum capacity. As such, this approach represents, from the perspective of operational constraints of the transmission network, an ideal setting, matching the approach we also adopted in relation to thermal and hydro generation unit availability.

The approach adopted in this project can be contrasted with the more realistic 'n-1' transmission configuration scenario which typically involves subtracting the largest individual line from the group connecting nodes. This latter approach is linked to reliability considerations that ensure that things do not go ‘pear shaped’ if the largest single line is lost, and as such, is a more realistic operational setting.

The main reason we adopted the ‘n’ transmission configuration scenario was the length of the time interval involved with the project, which goes out to 2047. As such, we are sacrificing some operational realism in the near turn but also recognising that the current ‘n’ scenario might well become an ‘n-1’ scenario towards the end of the simulation time horizon if additional transmission lines were to be added.

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