Electricity sales and maximum demand forecasts for Tasmania to 2045

CONFIDENTIAL

A report for
TASNETWORKS

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1. Introduction and study scope

The TasNetworks invited the National Institute of Economic and Industry Research (NIEIR), trading as National Economics, to develop electricity sales projections for Tasmania to 2045. Maximum demand forecasts for Tasmania were also requested for summer and winter peaks to 2045.

The scope and key requirements of the study are as follows.

1.1 Background

TasNetworks, Tasmania's Transmission and Distribution Network Service Provider has the responsibility to prepare the load forecast for the NEM Registered Participants and the Tasmanian Energy Regulator.

NIEIR's forecasts will be used to:

- develop TasNetworks energy and demand forecast;
- develop TasNetworks medium and long term planning studies;
- report forecast for the Revenue Proposal and the Pricing Determination;
- report forecast energy and maximum demand growth and system constraints in TasNetworks Annual Planning Report;
- report on forecast energy use, energy generation and maximum demand for the Tasmanian Energy Regulator, NEM Registered Participants and the general community; and
- provide data and comments for AEMO Electricity Statement Of Opportunities (ESOO).

This year TasNetworks requires two energy and maximum demand forecasts

1. Prepare the energy and maximum demand forecast by 14 December

TasNetworks requires an energy and maximum demand (MD) forecast up to year 2045 (inclusive). Forecasts are to be prepared by NIEIR for TasNetworks with low, medium and high energy and demand growth scenarios for:

- winter maximum and summer maximum demand for:
  - total State MD;
  - retail customers;
  - transmission directly connect customers;
- electrical energy sales (used); and
- electrical energy generated (sent out). The data for electrical energy generated will be based on generator terminal measurements.

TasNetworks would require the following information documented in the report:

- comparison of AEMO's latest load forecast for Tasmania and NIEIR latest forecast;
- actual and temperature corrected historic winter and summer maximum demand data with temperatures for 10, 50 and 90% POE;
- methodology used in determining base temperatures used in POE in particular the relationship between to maximum demand days and base temperature;
- a list of macroeconomic indicators used on the medium, high and low scenarios;
- a commentary on the macroeconomic indicators used in preparation of the forecast;
- a list of contributing factors used for the retail load and directly supplied customer forecasts;
- a table of diversity factors used for the direct supplied customers forecast;
- a summary on how losses are treated in the forecast model;
- assumed price elasticity forecast for Tasmania;
- list of non-scheduled generators assumed in the forecast model and their contribution to the MD;
- impact of wind generation to the maximum demand – Musselroe wind farm and Woolnorth (Bluff Point and Studland Bay);
- assumptions made on:
    - price responses;
    - voluntary demand response at time of peak;
    - impact of energy efficiency schemes in Tasmania;
    - impact of PV penetration;
    - impact of Aurora demand-side management programs;
    - electric vehicles;
    - carbon tax;
- retail price forecast and assumptions;
- discuss the significant step increase/decrease from historic data to forecast data;
- comment on initial change from historic values to forecast values noting any abnormal increases/decreases in the forecast;
- include a summary of diversity factors and losses assumed;
- a graphical comparison of this year's medium maximum demand projections (90, 50 and 10% POE) with last year's medium maximum demand projections including the reasons for any changes;
- include 10-year back-casting graph. If back-casting highlights any issues, the correction factors need to be identified:
    - actual MDs versus ex-post, out-of-sample forecasts based on actual conditions;
    - actual MDs versus ex-post, within-sample calculated 10%, 50% and 90% POE levels;
    - a more detailed commentary to back-casting methodology and assumptions used;

- include actual demand values as well as corrected value;
- 90, 50 and 10% POE to be included; and
- adjust the forecast with new assumptions;

■ include recalculation of estimates for non-scheduled generators (Butlers Gorge, Rowallan, Paloona, Repulse and Cluny) for summer and winter;

■ recalculation of reference temperature based on recent years and table to be included;

■ POE percentage of last 10 year's winters and summer for the one year and two year out back assessment (based on the method used for MD forecast). This is POE% of the actual value from the forecast values provided. It is TasNetworks preference that NIEIR conducts a back assessment exercise (in addition to the back casting exercise) for the last 10 years and includes the POE% from the actual;

■ spreadsheet and graph of results of the 10 year back casting, based on the current MD projections. The spreadsheet should include Total MD fitted, Total MD actual, Total MD residual and percentage error;

■ include confidence intervals of the forecast value;

■ root mean squared error and comments; and

■ measurement of back-cast accuracy by mean absolute error (MAE).

Deliverable: A draft delivered by 14 December 2014

2. New load forecast based on the tariffs model using AEMO economic scenarios

TasNetworks requires NIEIR to use the AEMO macroeconomic forecasts (together with the AEMO economic scenarios) to produce a high, medium and low energy and maximum demand forecast for winter and summer. These maximum demand forecasts are to be extended to 10, 50 and 90% POE due to temperature variations.

Key deliverables

■ A short-term (0-3 years) and longer term (30 year) energy and maximum demand forecast.

■ Consumption forecasts by network tariff.

■ Summated demand (any time maximum) forecasts by tariff.

■ Indicative load profiles by customer type (residential, commercial etc.) to aid in the development of demand based tariffs for small customers.

Deliverable: By 14 February 2015.

Input from AEMO

TasNetworks will provide NIEIR the following AEMO reports, which are to be used in the NIEIR forecast:

- List of forecasted macroeconomic variables for Tasmania; and
- Economic scenario.

1.2 Data to be provided by TasNetworks

Half hourly data on the following.

- System generation MW to meet Tasmanian demand considering the impact of Basslink transfers.
- Basslink import and export data.
- Generation required to meet Tasmanian demand (exclude Basslink transfers).
- Bell Bay Aluminium (Comalco Substation 220 kV).
- Carter Holt Harvey (Temco Substation 110 kV).
- Nyrstar (Risdon Substation 11 kV).
- Norske Skog (Boyer Substation 6.6 kV).
- Mining & Manufacturing Group Rosebery (Rosebery Substation 44 kV).
- Copper Mines of Tasmania (Queenstown Substation 11 kV).
- Grange Resources Tas (Port Latta and Savage River Substations 22 kV).
- Gunns (Hampshire Substation 110 kV).
- Hellyer Gold Mines (Que Substation 22 kV).
- Forest Enterprises Australia (Huon River Substation 22 kV).
- Non-scheduled generation information from:
  - Cluny and Repulse;
  - Butlers Gorge;
  - Paloona;
  - Rowallan;
  - Woolnorth – Bluff Point and Studland Bay; and
  - Musselroe.
- List of embedded generation information from:
  - Simplot;
  - Newton; and
  - Arthurs Lake.
- Annual sales by class.

Data requirement for tariff based forecast.

- TasNetworks retail tariff data.
- Tariff code translations.
- Network tariff price guide.
- Historic consumption by tariff.
- Customer numbers by tariff.
- Large customers (HV and above) data for 2011-12, 2012-13, 2013-14.
- Stratified random sample of 2500 medium customers (LV customers) data for2011-12 2012-13 2013-14. This includes name, address, NMI, usage, network tariff.
- New customers in 2007-08 and their consumption for 2008-09 2009-10, 2010-11 , 2011-12, 2012-13,2013-14.
- New customers in 2008-09 and their consumption for 2009-10 2010-11, 2011-12, 2012-13, 2013-14.
- New customers in 2009-10 and their consumption for 2010-11, 2011-12, 2012-13, 2013-14.
- New customers in 2010-11 and their consumption for 2011-12, 2012-13, 2013-14.
- New customers in 2011-12 and their consumption for 2012-13, 2013-14.
- New customers in 2012-13 and their consumption for 2013-14.

Final deliverable

- Electronic copy of the draft report for comments.
- Finalised spread sheet data.
- Hard copy of the report.

Timing and fees

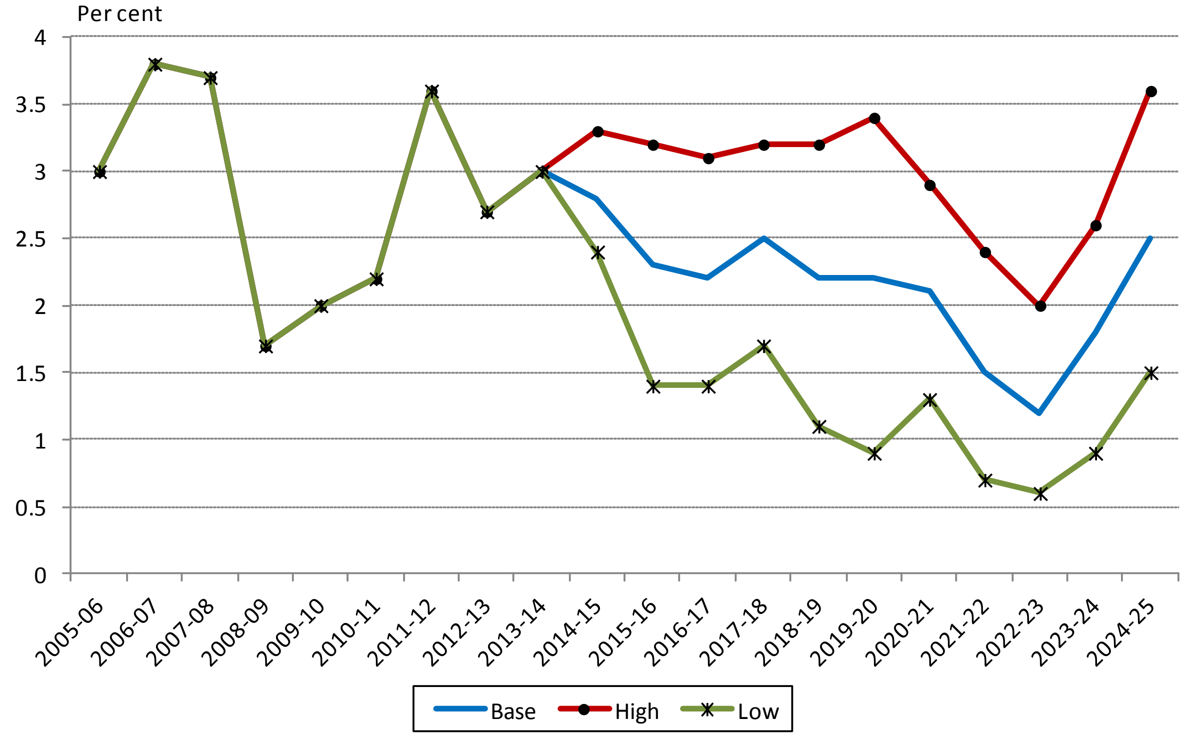
The final NIEIR forecast report is to be completed and delivered to Dinesh Perera at TasNetworks by 28 February 2015.

2. The economic outlook for Australia and Tasmania to 2024-25

2.1 Introduction

This section provides an outline of the economic outlook for Australia to 2024-25. Figure 2.1 shows the outlook for Australian gross domestic product to 2024-25 by scenario. Table 2.1 shows the projected annual Australian GDP growth rates to 2024-25 for each of the scenarios. These economic forecasts were prepared in July 2014.

Figure 2.1: Australian GDP growth by scenario (annual per cent change)



Note: Financial years ending June.

Table 2.1 gives span growth rates across each scenario for Australian GDP growth. Figure 2.1 shows the graphical profile for the key high, low and medium scenarios. The cyclical profiles in Figure 2.1 reflect the cycle in the world economy.

Table 2.1 Australian GDP growth under each scenario (per cent)			
Financial year	**Base**	**High**	**Low**
2005-06	3.0	3.0	3.0
2006-07	3.8	3.8	3.8
2007-08	3.7	3.7	3.7
2008-09	1.7	1.7	1.7
2009-10	2.0	2.0	2.0
2010-11	2.2	2.2	2.2
2011-12	3.6	3.6	3.6
2012-13	2.7	2.7	2.7
2013-14	3.0	3.0	3.0
2014-15	2.8	3.3	2.4
2015-16	2.3	3.2	1.4
2016-17	2.2	3.1	1.4
2017-18	2.5	3.2	1.7
2018-19	2.2	3.2	1.1
2019-20	2.2	3.4	0.9
2020-21	2.1	2.9	1.3
2021-22	1.5	2.4	0.7
2022-23	1.2	2.0	0.6
2023-24	1.8	2.6	0.9
2024-25	2.5	3.6	1.5
Compound average annual change			
2012-13 to 2024-25	2.1	3.0	1.3
2013-14 to 2018-19	2.4	3.2	1.6
2018-19 to 2024-25	1.9	2.8	1.0

2.2 The world and national outlook

2.2.1 Introduction

The major change since the last economic update involves an upward revision to the risks that may impose negative outcomes to the economic outlook in both the world and Australia.

The risks can be classified under a number of different headings. Firstly, there is the **global security deficit** risk under which falls those factors which are leading to increased political and military tension between the major world economies. These factors are increasing and operate in Eastern Europe, the Middle East and North Asia. If these factors cannot be contained then there is likely to be major shocks to the world economy in terms of trade disruption, sanctions, investment barriers and a major diversion of resources to military arms build-ups.

The second risk is **financial risk**. The initial reaction to the GFC was a commitment to develop global based rules of financial regulation to stop the excessive borrowing, shadow banking and reckless lending that led to the GFC. Unfortunately, strong progress in regulation has been limited to unilateral actions and strong across-the-board financial market global solutions have proved elusive. Some believe that the financial instability associated with the GFC will be repeated over the next few years.

The third risk is the **secular stagnation** risk. The secular stagnation risk recognises that the developed world in particular is characterised by a liquidity trap situation where interest rates have fallen as low as they can go with the result that monetary policy is ineffective in stimulating aggregate demand. With governments unwilling to use fiscal policy because of (largely unwarranted) public sector debt considerations there are no tools available to bring aggregate demand up to the level that is necessary to restore confidence and high long-term growth.

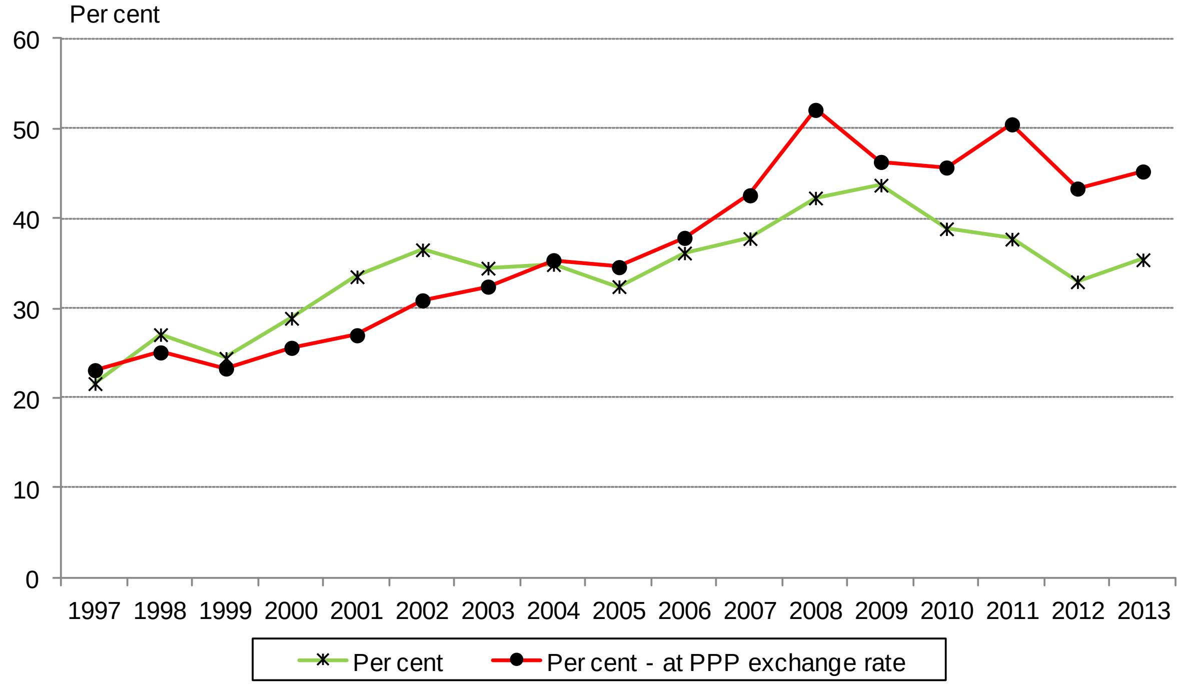
In the case of Australia there is **meltdown** risk. A meltdown is characterised by an economy subject to firstly a balance of payments crisis, then an exchange rate crisis and finally a banking crisis. This risk flows from the fact that Australia’s gross international debt and short-term debt as a percentage of GDP are currently well in excess of the values that prevailed for those countries that have suffered a meltdown over the last 16 years. That is, the Asian economies in 1997 and the European economies in 2009. More importantly, the meltdown risk will increase significantly over the coming years as the current account deficit increases, debt to GDP ratios further increase and the difficulties associated with a significantly overvalued currency returning to more normal levels.

Perhaps the best indicator of Australian economic vulnerability is given in Figure 2.2, as Australia’s annual foreign debt borrowing requirement or foreign debt of less than one year to maturity plus the projected current deficit less foreign reserves. This is currently running at a third of GDP, but at a purchasing power parity exchange rate of 70 cents to the US dollar it would be 43 per cent of GDP.

In the past, countries with rates above 25 per cent of GDP have been subject to exchange rate-balance of payments-banking crisis.

The fact that a large part of the foreign debt is held by banks, or approximately 30 per cent of total liabilities, means that the risk is that a banking crisis will be triggered by a balance of payments crisis.

Figure 2.2: Australia – Short-term international borrowing requirement to GDP ratio



The general economic outlook for the Australian economy is one where the trend rate of growth is below the historical benchmarks. Growth is high over 2015 and 2016, however, this largely reflects the high levels of mining investment and in particular LNG. Although the population growth rate does fall it is unlikely to fall to the levels required to prevent further steady increases in the unemployment rate, which reaches over 8 per cent by the end of the projection period.

2.2.2 The world economy

Six years after the GFC the uncertainty surrounding the medium-term direction of the world economy is perhaps, except for 2009, at its highest point. The issues are straightforward. This uncertainty is manifested in the range of opinions in answers to the following questions. Will the world economy accelerate over the next 2 or 3 years as has been the long-term expectation? Will growth stay near current levels with rising unemployment and increasing political instability? When will interest rates start increasing from current low levels with negative real interest rates prevailing in a number of economies and do policies have to change, and change to what, if the world, that is the developed world in particular, is to accelerate its economic growth? Has there been a fundamental economic and political structural change in the world economy which must be addressed if growth is to return to near pre-2009 levels? In many countries firm profitability has returned to pre-2009 levels but investment effort remains very weak, thereby being a significant constraint on growth. Reasons for this are advanced below.

The impact of austerity policies are clearly seen from inspection of the world GDP quarterly growth rate profile. At the height of the stimulus introduced in response to the GFC world economic growth peaked at 5 per cent at the end of 2010. The withdrawal of stimulus saw the world GDP growth more than halved to a trough rate of 2 per cent at the end of 2012. Since then world GDP growth has slowly recovered reaching 3 per cent at annual rates in early 2014.

Political risk

One factor that now is getting attention is increasing uncertainty, and thereby weakening the incentive to invest, because of the deterioration in the geopolitical outlook. There is no doubt that the fallout from the Ukraine crisis and the continual threat of Russian invasion given the build-up of armed forces on the Ukrainian border has been a major factor in weakening the EU economic recovery over the course of the last 6 months. The fact that Russia contributes approximately a third of Western Europe's gas supply, which could be cut off at a time of crisis with large economic damage, would be a factor weighing on the timing and scale of investment decisions. The current round of tit-for-tat sanctions and likely increase in the scale of sanctions is another factor reducing the short-term appetite for investment.

Unless there is a change in Russian leadership and the strategic objectives of the Russian Federation it is difficult to see how a continual decline in the security risks for Western Europe can be avoided, representing a partial return to the political economy of pre-1990.

In North Asia the continuing disputes over islands, which is driven by the wider issue of the control of the China Sea, will not go away and can only intensify as China's military build-up continues. In 2014 China have 50 significant naval vessels under construction, including the construction of at least one large scale aircraft carrier and two smaller carrier assault vessels. Hardly a week passes without some close encounter between Chinese military aircraft and vessels and those of Japan, the United States, or Vietnam.

It is difficult to see how the deteriorating strategic outlook in North Asia is going to be resolved. The sharp acceleration in the arms race between China and the rest of Asia which, if continued, could easily evolve into a post 1947 Cold War trade block regime that characterised Europe until 1990. The problem here is that unlike Russia in 1947, China is now the world's largest trading power with extensive links to almost all countries. In 1947 Russia's links outside its sphere of influence were very weak. At the very least, over the next decade it is likely the trading relationships between Australia and China will become more political, uncertain and volatile.

It is the declining longer term geopolitical outlook which is the main reason for the weak economic outlook for the world economy post-2017.

Economic policy

What economic policies are pursued to accelerate the growth in the world economy have a critical importance for Australia. This is not just because of the level of activity in the world economy, but because of the likelihood of the timing of the increase in world interest rates which will have major consequences for the Australian exchange rate and, therefore, the competitiveness of the Australian economy. With reversal of the post-2008 stimulus policies over 2011 and 2012 the main developed world policy stance has been one of austerity. By this is meant consolidation of fiscal policy deficits so as to stabilise, at the very least, the increase in the debt to GDP ratios. The central idea of this was that growth would be stimulated by the confidence this would give to the private sector that they would not be crowded out by public sector demands, low risk of future taxation rate increases, and interest rates being kept relatively low.

It is clear that almost all this policy stance will not lead to acceleration in growth in the foreseeable future. This is despite policies of so-called quantitative easing, where the Central Bank buys up private sector asset backed securities to increase liquidity in the economy, lower interest rates and increase established asset prices in the hope of wealth effects and lower cost of capital stimulating investment. In short, monetary policy has now limited effectiveness because interest rates are at minimum levels. This situation was well documented in the 1930s as described by the textbook Keynesian liquidity trap.

Private sector investment has failed to respond for the simple reason that excess capacity remains high in most developed economies and, therefore, there are limited investment opportunities. Austerity policies have contributed to this by reducing demand and therefore capacity utilisation rates from levels that otherwise would have prevailed. The objective of controlling government debt, in terms of liquidity impact on the economy, has lost credibility because real interest rates are negative in a number of key economies, implying that nominal interest rates are as low as they can go.

These simple points are now being more widely recognised, especially amongst the institutions that matter in setting the framework for economic policy in developed economies. That is, the IMF and the European Central Bank. In an important speech to the meeting of central bankers in Jackson Hole, Wyoming, in late August 2014, the head of the European Central bank called for greater reliance on fiscal policy to drive European economic recovery. How the German objections to this strategy can be overcome only time will tell, though rising youth unemployment rates which will trickle down into the unemployment rates of those aged between 25 and 34 over the next few years will be a powerful political stimulus to find a way through the political obstacles.

The issues are, however, more complex than simply the effectiveness of monetary policy vis-a-vis fiscal policy. This revolves around the answer to the question of why central banks have persisted with quantitative easing despite interest rates being at minimum levels, even though the ECB has introduced negative interest rates on bank deposits at the ECB. The answer to this is that central banks have been targeting the exchange rate attempting to stimulate growth by a lower currency. Unfortunately, when all the major developed economies embark on such a policy its effectiveness is blunted with the exception of winning market share from smaller countries such as Australia, which continue to target the inflation rate rather than the exchange rate and, therefore, continue to have over-valued currencies, stagnant price sensitive exports and increasing import penetration.

It is assumed that there is, in Europe at least, a shift in emphasis from monetary policy to fiscal policy. However the shift is likely to be slow, only having a gradual impact on accelerating growth with the impact being noticeable at around 2016-17.

The permanent loss of capacity

The cost of the GFC is increasing with each passing year. For 2015 the estimate is that the loss and potential output, that is, compared to the likely values that would have prevailed in 2015 if pre-2009 potential growth rates had been maintained, is estimated at 11 per cent for the Euro area, 5 per cent for the United States, 10 per cent for Japan and 12 per cent for the United Kingdom, giving a core developed world total of 8.5 per cent. More importantly, because of the decline in investment over this period, the actual new capacity by 2015 is estimated at 2 per cent for the Euro area, 2 per cent for the United States, zero for Japan and zero for the United Kingdom. This result is because actual capacity installed in 2015 will be much lower than what would have been installed if pre-2009 growth rates had been maintained. If these estimates are correct it indicates the capacity by the policy authorities to grow demand to stimulate their economies.

More importantly, the post-2009 outcomes are also likely to have reduced the underlying growth in potential output because of lower rates of innovation, lower rates expenditure on R&D, decaying workforce skills of those forced into the long-term unemployment, and lower productivity growth rates stemming from simply lower growth overall as economies of scale and scope that otherwise would have been achieved have not materialised. It has been estimated that the underlying capacity growth rate has fallen from 2 to 1 per cent in the Euro area, 1.4 to 0.8 per cent for Japan, 2.6 to 2.2 per cent for the United States and 2.7 to 1.9 per cent for the United Kingdom. These declines were lower than the longer term potential of the world economy.

When will interest rates rise – the use of macro prudential tools?

What is now widely recognised is that the worst possible thing for the developed world economies would be to increase interest rates to correct for sector imbalances, such as rapidly increasing established house prices. To avoid this there is increasing interest in using so-called macro-prudential tools to leave interest rates unchanged, but still act to correct imbalances such as overheated housing markets. Macro-prudential tools represent no more than the use of finance sector quantitative control tools that was common before the 1990s. Use of such tools would be, for example, specifying maximum loan to asset valuation ratios (that were lower than current practise), maximum loan periods, and mandated asset allocation rules in relation to mortgage based assets, liquid assets and commercial loans. In mid-2014 the New Zealand central bank applied macro-prudential rules to stabilise the domestic housing market. The UK central bank is also slowly expanding the use of such rules.

There will be upward pressure on interest rates, however, if, for the only reason that quantitative easing will have to be wound back to avoid large increases in risk in finance enterprise balance sheets. The expansion in quantitative easing has allowed large-scale financial engineering to occur, particularly in derivative markets. As of pre-2008, no-one is sure of what risks are being built up, especially for investment strategies and products that don't take account of increases in interest rates. It is this fact that leads some to conclude that if left unchecked the current policies will lead to another GFC four or five years down the track.

Thus, the expectation is that the withdrawal of quantitative easing in the United States, for example, will force interest rates up over the second half of 2015. A poorer economic outlook than what is currently expected may well postpone this into 2016, especially if macro-potential tools are employed to target financial stability.

In viewing the current evidence it is likely that the significant upward shift in interest rates will be postponed, at least to the end of 2015 and probably into 2016, with the increase being less than what was previously expected because of the likelihood that key developed economies will resort to quantitative control measures and, secondly, because of the increasing loss capacity in most developed economies relative to pre-2009 trends which will be reflected in steadily increasing real unemployment rates, if not in the headline unemployment rate.

Nevertheless, the negative fallout from the ending of quantitative easing and the increase in interest rates is likely to cause economic costs being imposed on both developed and developing economies. This is simply because of the build-up of excessive debt and risky financial products that have occurred over the last two to three years. These costs will be realised over the 2016 to 2018 period, which is yet another reason for expecting the economic outlook at the end of this decade to be somewhat subdued.

The emerging economies that are most likely to be impacted on from the ending of quantitative easing and the rise in interest rates are the so-called "Fragile Five" economies of:

- Argentina;
- Brazil;
- Indonesia;
- Turkey; and
- South Africa.

Figure 2.3: World – Real GDP growth rate

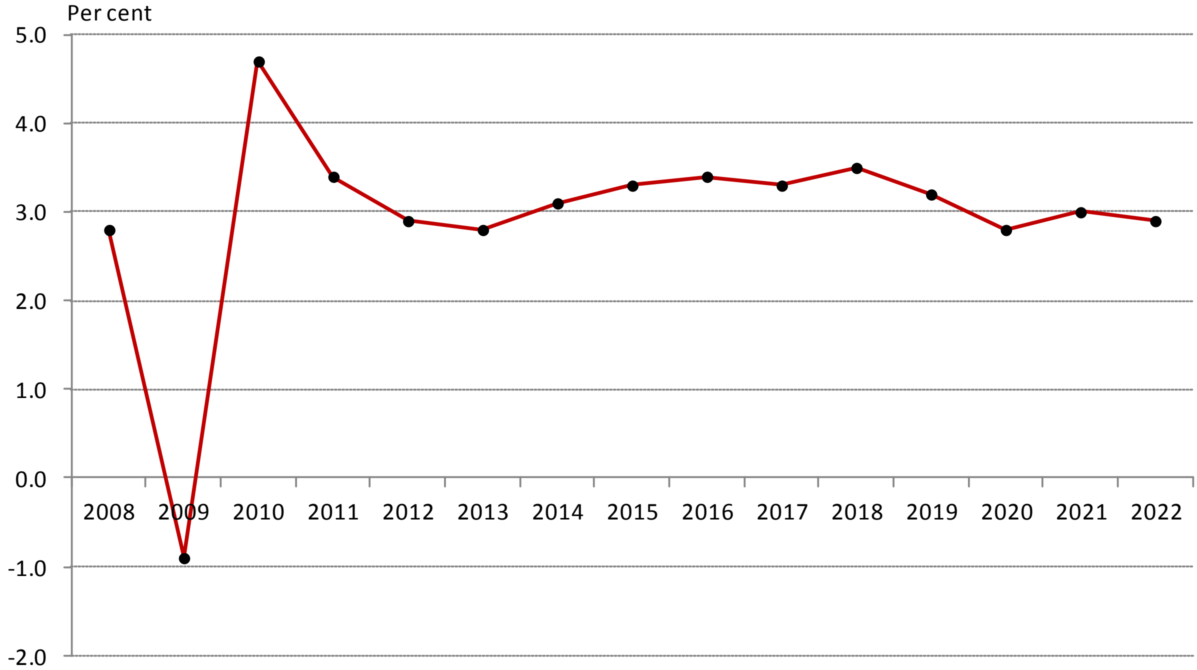


Table 2.2 Formation of Australian GDP (per cent)										
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
International (calendar year)										
World GDP	3.4	2.9	2.8	3.1	3.3	3.4	3.3	3.5	3.2	2.8
Demand										
Private consumption	3.7	2.5	2.1	2.5	2.6	2.9	2.6	2.7	2.4	2.0
Business investment	5.7	14.9	5.2	-2.4	7.1	2.7	-1.5	-4.7	-2.6	-0.8
Housing	2.2	-2.2	-0.2	5.6	13.8	2.5	-3.4	-7.5	-4.1	0.5
Public Current expenditure	3.3	3.8	0.8	2.0	1.9	1.8	2.3	3.0	2.9	3.0
Public Capital expenditure	-3.3	-3.0	-9.5	6.6	-0.2	-10.3	-8.4	-1.2	5.4	2.8
Total expenditure	3.6	5.1	2.0	1.4	3.3	2.0	1.1	0.9	1.5	1.6
Exports	0.6	4.7	6.0	7.4	3.7	5.0	5.2	7.3	4.4	2.0
Imports	10.2	11.4	1.0	-2.1	8.4	4.5	1.0	1.0	2.2	1.6
GDP	2.2	3.6	2.7	3.0	2.8	2.3	2.2	2.5	2.3	2.2
External sector										
Current account deficit ($B)	-42.1	-48.5	-58.0	-40.7	-56.9	-62.8	-53.9	-47.2	-41.4	-64.6
CAD as per cent of nominal GDP	-3.0	-3.3	-3.8	-2.6	-3.4	-3.6	-2.9	-2.5	-2.1	-3.1
Labour market										
Employment	2.4	1.2	1.2	0.8	1.1	0.9	1.0	1.2	1.2	1.3
Unemployment rate (%)	5.0	5.2	5.4	5.8	6.0	6.2	6.5	6.4	6.2	6.4
Participation rate (%)	65.5	65.3	65.1	64.8	64.4	63.9	63.6	63.2	62.7	62.5
Finance										
90 day bank bill (%)	4.9	4.4	3.2	2.6	2.6	2.8	3.5	3.5	3.8	4.4
10 year bond rate (%)	5.3	4.0	3.2	3.4	4.0	4.0	4.1	4.1	4.1	4.2
$US/$A	99.0	103.3	102.7	91.8	92.3	90.5	88.7	87.5	83.5	78.4
Trade weighted index	74.0	76.3	77.0	70.5	70.3	68.3	66.6	65.4	61.4	55.4
Wages and prices										
Average weekly earnings, all persons: Total earnings – full-time (seasonally adjusted)	4.3	4.6	4.6	2.9	3.5	3.2	2.9	2.7	2.4	2.8
CPI	3.1	2.3	2.3	2.7	2.2	1.8	2.1	2.8	2.6	3.0

2.2.3 The economic outlook for Australia to 2020

Gross Domestic Product

The current underlying growth of Australian GDP is 0.7 per cent per quarter, or just under 3 per cent per annum.

Australia's economic growth is forecast to be in the vicinity of 3.5 to 4 per cent over the next couple of years. It is true that mining investment is projected to fall by between $30 and $40 billion over the next couple of years. However, a large part of this fall will represent expenditures, especially on LNG plants, with very high import component. Therefore, the impact on domestic economic activity will be relatively subdued.

Dwellings investment is projected to add 0.7 percentage points to the national GDP growth rate in 2015. In 2016 the impact of the dwelling cycle peaks with 0.1 percentage points added to the national GDP growth rate and for the rest of the projection period dwelling makes a negative contribution. In 2014 exports are estimated to have contributed over half of the GDP growth rate with the contribution being 1.6 percentage points, compared to the estimated national growth rate of 3 per cent. In 2015 the contribution of exports is projected to fall to 0.8 percentage points, largely because of the impact of mild El Niño, which will reduce the impact of an otherwise continually strong mining contribution. A 1 percentage point plus contribution to the national GDP growth resumes in 2016 with the average contribution over the four years to 2019 being 1.4 percentage points.

The contribution of private consumption expenditure, although increasing marginally in both 2015 and 2016 by 0.1 percentage points in both years, is well below the pre-2009 contribution of an excess of 2 percentage points per annum. Traditionally, with strong growth in dwelling prices and real wealth, the expectation would be that private consumption would add additional growth of up to 1 percentage point to GDP. Why is this not being predicted?

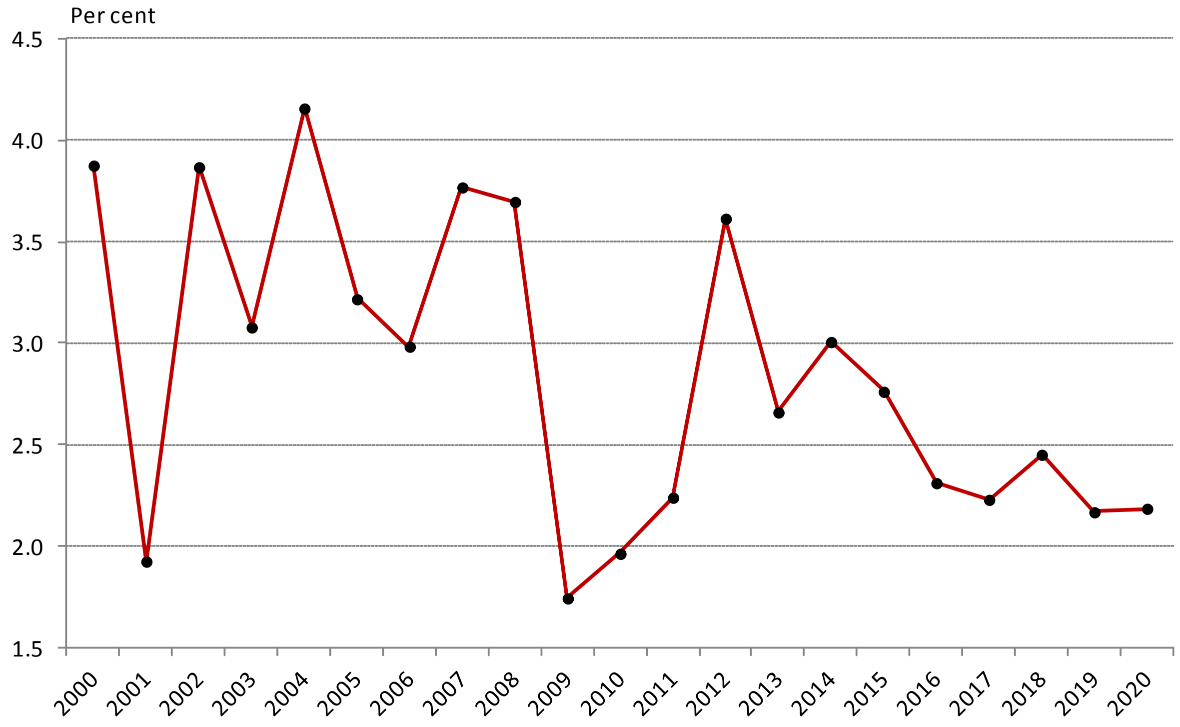
There are a number of elements contributing to this outcome. Firstly, productivity growth is low due to short and long-term factors. Long-term factors include the under-investment in infrastructure, while short-term factors include the hollowing out of the Australian economy due to the so-called Dutch disease which appears to have destroyed more middle income and employment as compared to low income and employment. Secondly, the steadily increasing underlying unemployment rate is operating to hold down the growth in nominal wages, resulting in relatively low growth in real wages. Thirdly, household debt at around 190 per cent of real disposable income appears to be at saturation levels so that consumption expenditure is constrained to real income growth.

Given the decline in mining investment, the contribution of total business construction investment to economic growth over the next couple of years is negative, but only marginally so.

Other than the sluggish growth in household consumer demand, the other main reason for a subdued national GDP growth rate over the next 2 to 3 years is the growth in imports. This will be associated with the ending of motor vehicle production and the echo effects of the high exchange rate over the last 3 or 4 years, which will result in the further closure of import competing capacity. Over the next two years, that is, over 2015 and 2016, the growth of import penetration is projected to reduce the national GDP growth rate by 1.2 percentage points per annum.

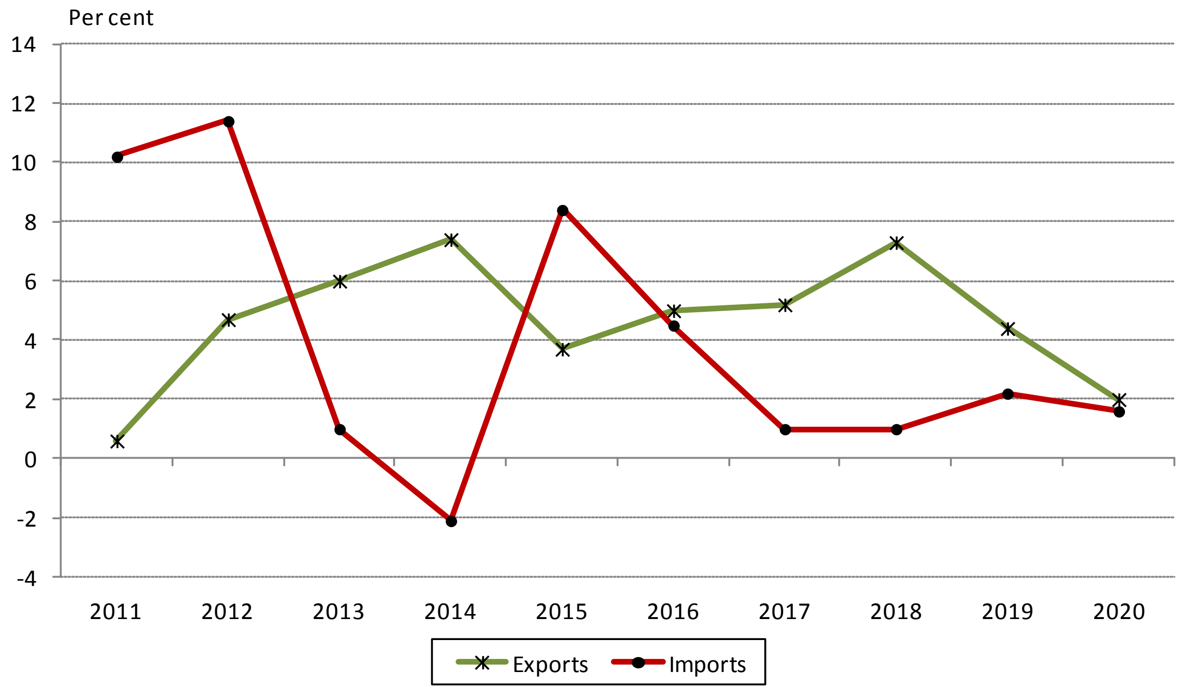
The post-2016 period is projected to be a period of particularly low GDP growth compared to the historical benchmarks. This will be the result of the mining sector returning to more normal contributions to GDP growth, the continued upward increase in effective unemployment rates squeezing real income growth, higher effective interest rates rendering a negative contribution of housing and business investment to national GDP growth rate, the return of the exchange rate to more competitive levels increasing domestic prices and thereby reducing real incomes, and the lower productivity growth rates that are the direct by-product of a relatively slow growing economy. The scope for Australian policy authorities to do much about the less than satisfactory profile post 2016 will be limited by the upward trend in the current account deficit and gross debt to GDP ratio. Any attempt to increase the national GDP growth rate by expansionary monetary and fiscal policies will increase the probability of a meltdown to unacceptable levels, given the high probabilities that currently exist.

Figure 2.4: Australian GDP



Note: Financial years ending June.

Figure 2.5: Overseas exports and imports of goods and services



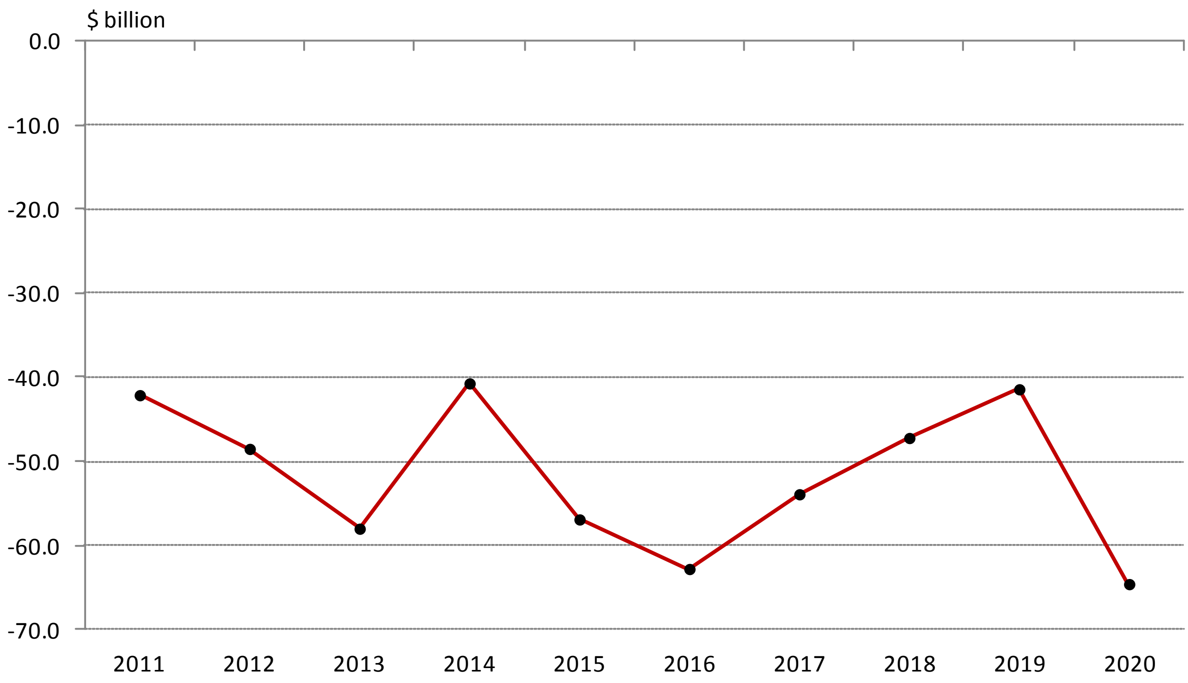
The balance of payments

The current account deficit, especially after 2016, is projected to deteriorate over the projection period. This deterioration will be driven by a number of factors. Firstly, there is the projected long-term fall in the terms of trade, a combination of lower world economic growth compared to expectations of 2 or 3 years ago, coupled with the supply response from recent peaks in commodity prices, that will combine to drive down real commodity prices. In part this will be because Australian producers, for iron ore in particular, are amongst the lowest cost producers in the world so there is an incentive, especially if they have a degree of domestic ownership, to increase production to drive down prices and increase market share knowing that the price effect will be compensated for likely falls in the Australian dollar. Nevertheless, the fall in the terms of trade from the 2012 peak is a relatively modest 20 per cent, given the pre-2004 terms of trade.

The rapid increase in income paid overseas over the next few years is driven by the recovery in world interest rates and the high mining income share that will be paid overseas because of the high foreign debt and foreign ownership of recent major mining projects.

Finally, there is the increased import penetration in the economy, due to the Dutch disease in general and the collapse of the motor vehicle industry in particular. The medium-term impact of a lower currency is likely to aggravate the current account deficit rather than reduce it. This is because of the impact of the exchange rate on Australia's foreign debt obligations and debt service ratios and the limited capacity that now exists in Australian manufacturing for import replacement.

Figure 2.6: Current account deficit



The household savings ratio

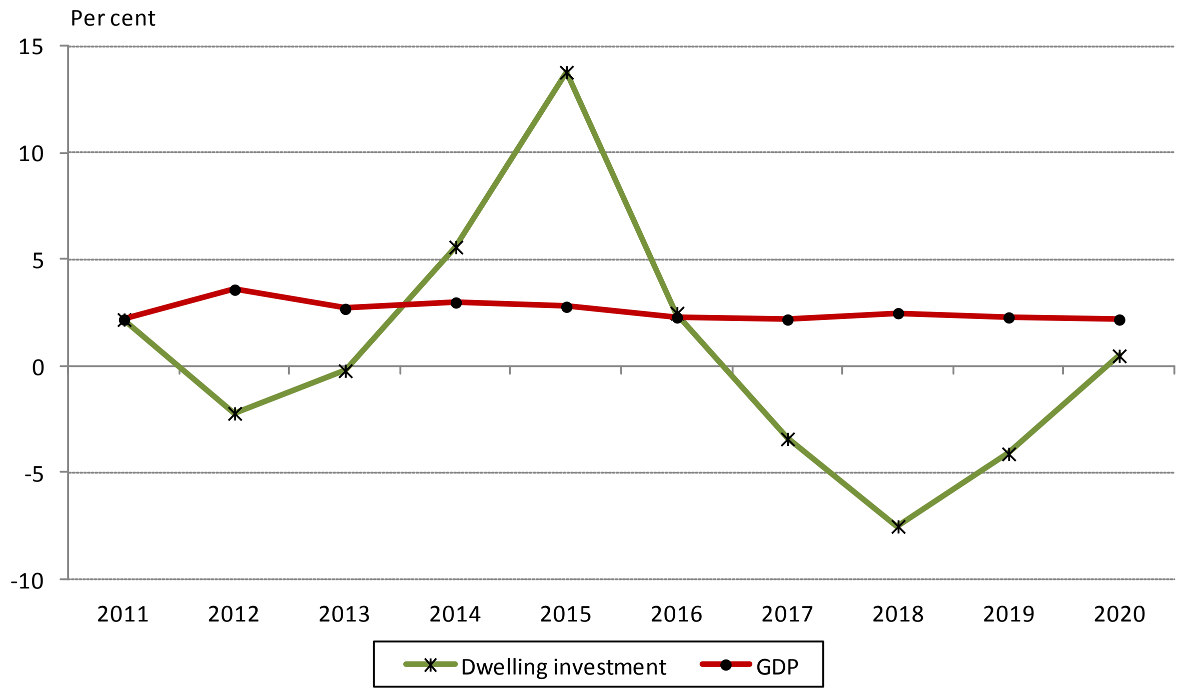
A core driver of the household savings ratio is the household debt to income ratio. With the rise in the household savings ratio at the end of 2009, the household debt to income ratio has stabilised. In the December quarter 2009 the household debt to income ratio was 180 per cent of net household income. In the March quarter 2014 it was 185 per cent, only slightly down from historical peaks in 2011. A ratio of around 185 per cent from the historical record appears to represent a ceiling, or debt saturation level, of debt given current debt service ratios.

A basic assumption of the previous projection was that the recovery of dwelling prices and the flow-on impact on wealth would encourage a downward trend in the household savings ratio and, therefore, an accelerated consumption growth that would drive national GDP growth to the 3 per cent to 3.5 per cent range over 2015 and 2016. Given the stability of the household debt to income ratio at the current household savings ratio, this assumed that households would be willing to increase the debt to income ratio.

To 2016 the household savings ratio is projected to be reasonably stable at near its current levels. It should be remembered that the constructional savings ratio through superannuation commitments is also near the current net savings ratio, implying a zero discretionary savings ratio.

Post 2016 the downward pressure on real income growth and increases in the debt service ratio are projected to place downward pressure on the household savings ratio as households attempt to maintain living standards, as reflected in per capita consumption expenditure by reducing savings.

Figure 2.7: Housing sector



Employment and unemployment

The projection for employment growth is one of a little over 1 per cent average per annum for the next two years, although declining to 0.8 per cent by the middle of 2016. A modest recovery to 1.3 per cent per annum by the middle of 2018 is forecast, before declining to 0.6 per cent by the end of the end of this decade. As the growth rate in employment is, in general, less than the working age population growth rate, the unemployment rate steadily increases reaching 7.5 per cent by the end of the decade and over 8 per cent by the end of the projection period.

In absolute terms, the level of unemployed is projected to reach 850,000 by the middle of 2016, 900,000 by the middle of 2019 and the politically sensitive benchmark of 1 million by the end of the decade.

Figure 2.8: Labour market

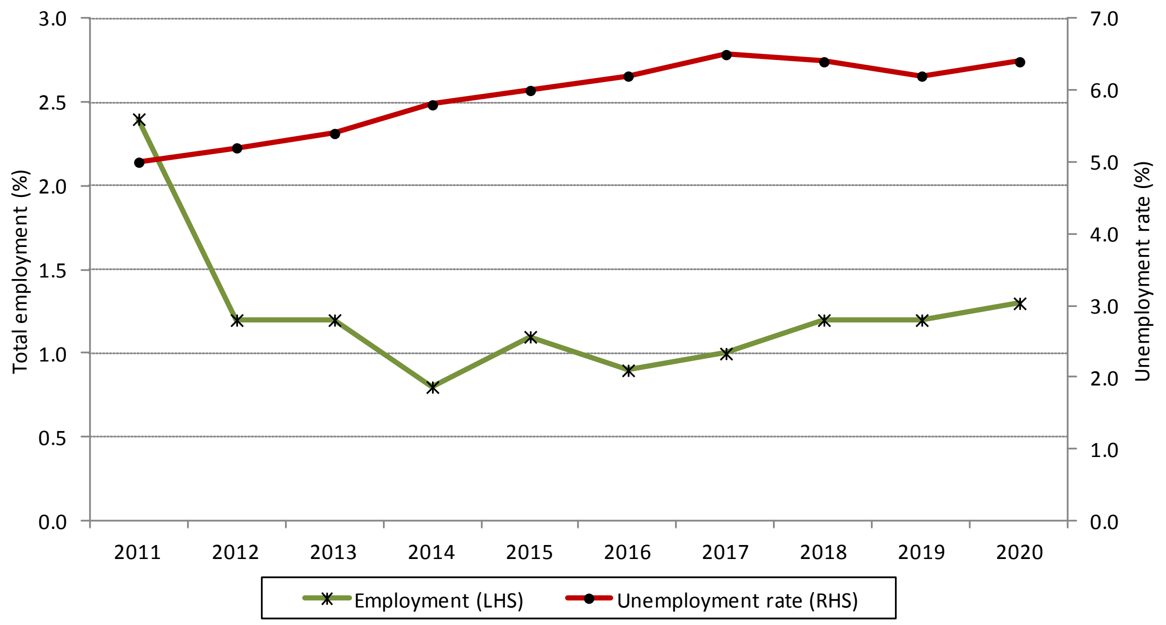
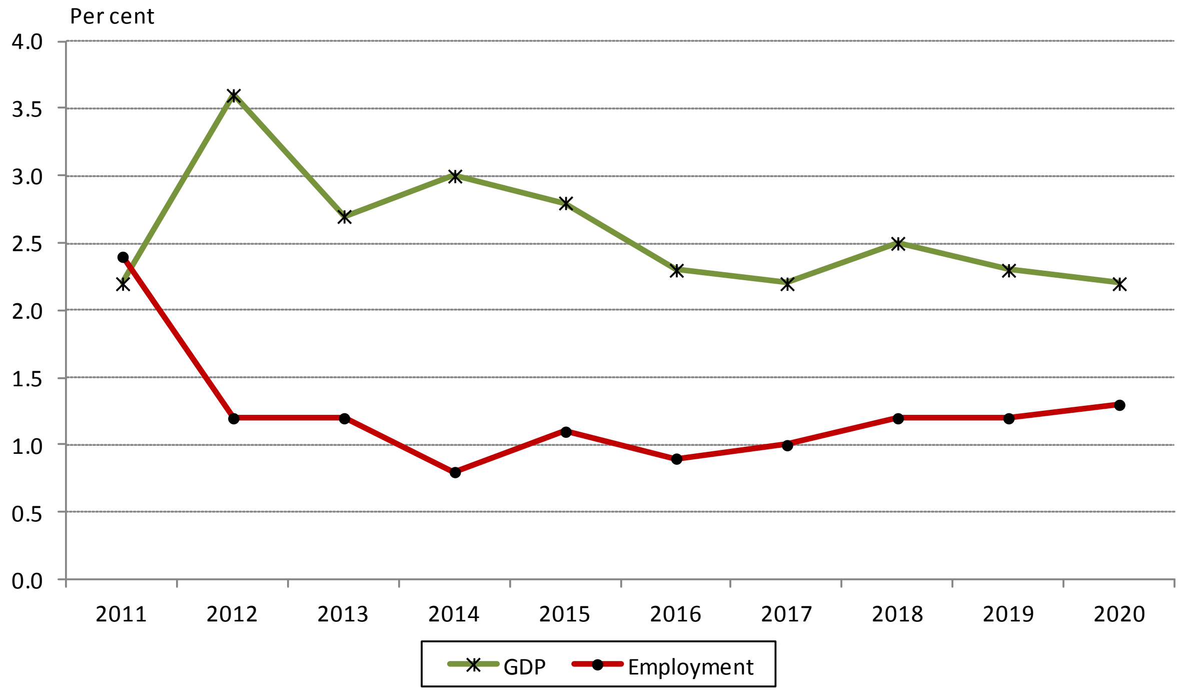


Figure 2.9: GDP and employment



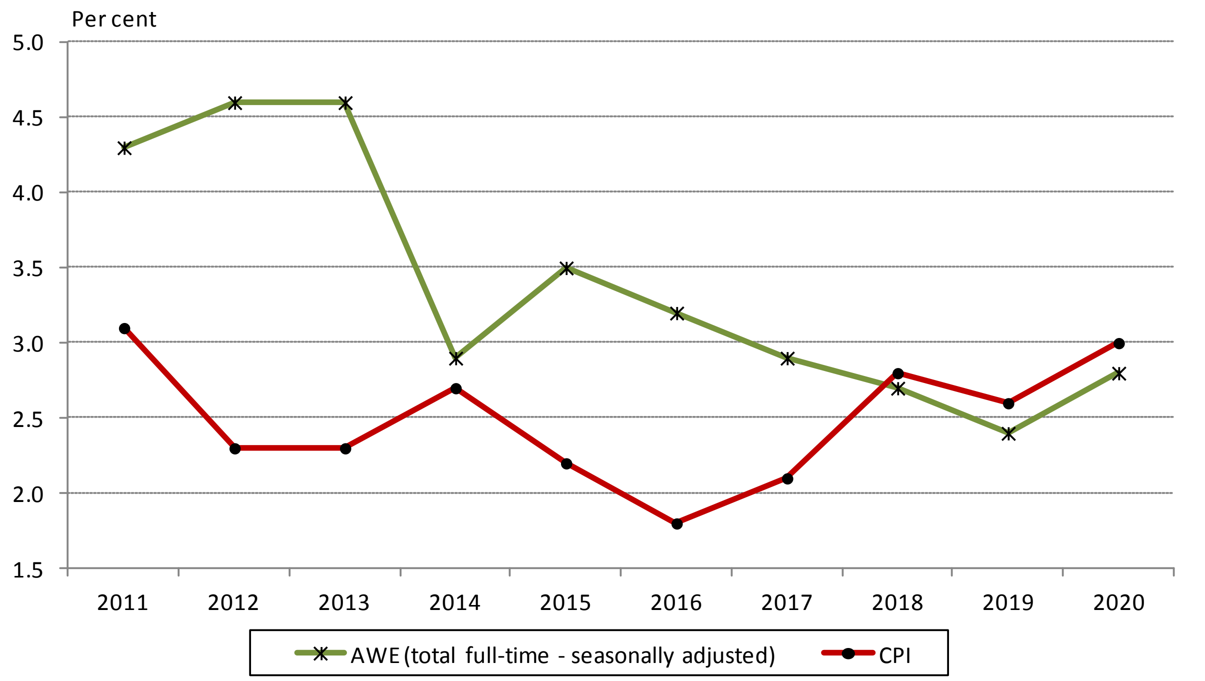
The inflation rate and wages

The steady increase in the unemployment rate and the projected increase in the unused capacity capital stock rate will combine to hold the inflation rate, measured by the CPI, at moderate trend levels of approximately 2 per cent per annum over the next two years. This outcome is assisted by only a modest reduction in the exchange rate to around 85 cents to the United States dollar. However, the fall in the currency begins to accelerate significantly after 2016, which will contribute directly to accelerating the inflation rate.

In addition, there is a limit to the extent that profit margins can be suppressed and the anti-inflation compression of profit margins will weaken, even if capacity utilisation rates continue to fall. In addition, once the exchange rate begins to fall significantly, profit margins can be expected to increase significantly in trade exposed industries.

Thus, from 2016 onwards the inflation rate is projected to increase steadily, reaching 3.5 per cent by 2018, at which point real wages will be declining by 0.6 per cent per annum. The stabilisation of the currency at near the purchasing power parity terms after 2018, with the unemployment rate settling at around 7 per cent, will combine to restore the inflation rate at the midpoint of the current RBA acceptable range for inflation.

Figure 2.10: Average weekly earnings and CPI



Interest rates

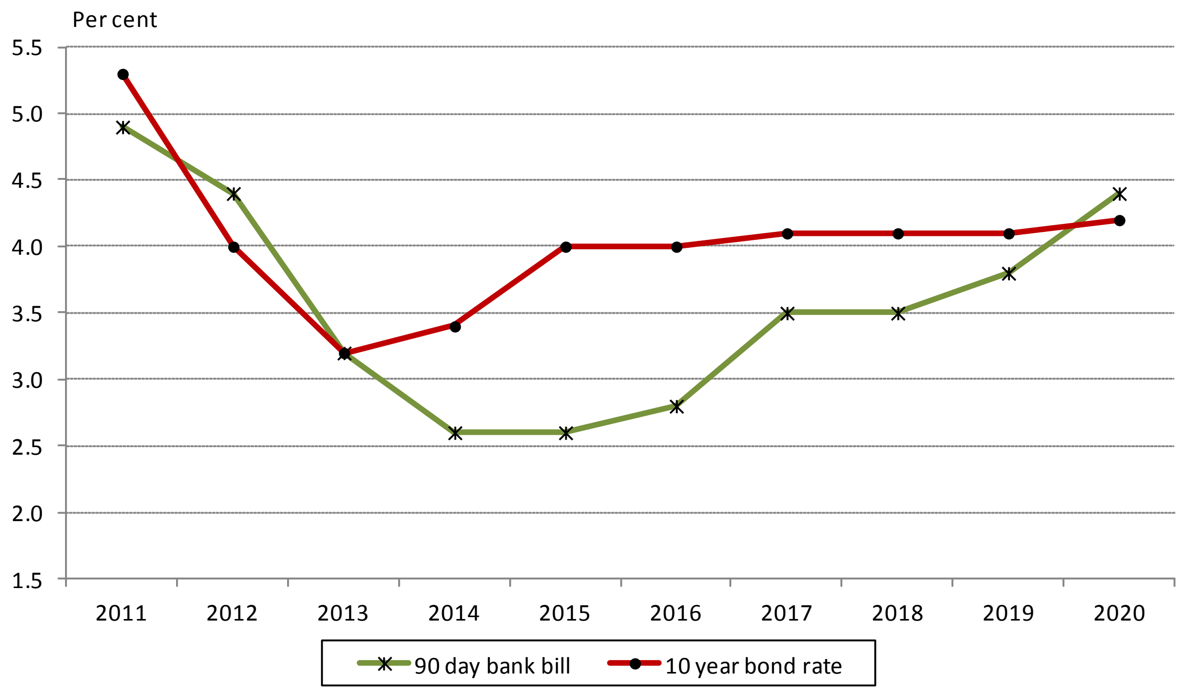
Currently there are two views in the market in relation to the short-term outlook for interest rates. One view is that the slow growth in the economy and the increasing unemployment rate will induce the RBA to reduce interest rates by the end of this year. The additional benefit of this is that it will lower the currency, thereby being an additional stimulus to growth. The other view is that the next move in interest rates will be upwards, although this may be put off well into 2015. This view contends that interest rates would be lowered because it risked giving even further stimulus to housing markets with the risk of higher excessive debt growth and structural imbalances in house prices. The proponents of macro-prudential regulation argue that if resort was made to these tools the housing market could be controlled and interest rates reduced.

The projections in this report accept the view that the next move in interest rates will be upwards, though postponed to the end of 2015.

After 2015 the increase in nominal interest rates will be modest, being targeted at maintaining the minimum margin over world interest rates to prevent the collapse in the currency. That is, interest rates are not predicted to increase above 4.5 per cent despite a lengthy period over 2017 to 2019 where inflation is above 3 per cent. This is due to the low growth and high unemployment rates prevailing over this period, where lower real interest rates will be used as a policy instrument to maintain minimal GDP growth.

The post-2016 period will be a very difficult time for monetary policy with low natural drivers of growth (with the ending of both the production and investment strong stimulus from mining expansion), inflationary pressures from the decline in the currency, and high current account deficits.

Figure 2.11: Interest rates



The exchange rate

As in previous reports, the two factors of:

(i) a long-term soft outlook for the world economy; and

(ii) the increase in the import propensity of the Australian economy via the destruction of manufacturing capacity, in conjunction with the ending of the strong stimulus from mining expansion,

will combine to ensure a decline in the Australian dollar. However, the weaker economy and the decline in mining investment will offset the combined impact of the two factors listed above.

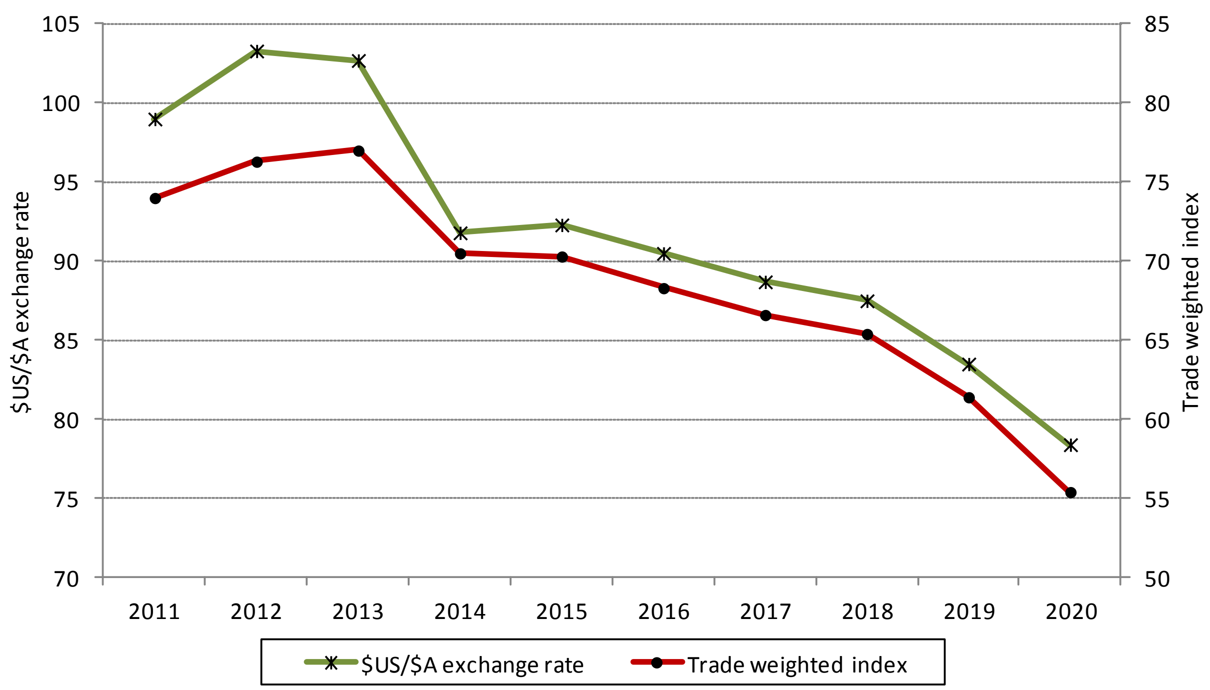
The lower domestic interest rate profile of this projection is partly offset by a lower world economic outlook and, therefore, lower world interest rates, for reasons given above, compared to what was projected in the last Bulletin at the end of 2013.

As a result, there is little change to the projected profile in the exchange rate.

Eventually foreign investors will be forced to realise that beyond the strong mining expansion phase such factors as high wealth immigration cannot disguise the fact that the Australian economy does not have the strength of broad-based drivers of the sustainable growth at historical standards other than the restoration of competitiveness by a low dollar. It is hoped that this revaluation does not lead to a weakening of the expectation that foreign lenders will eventually be repaid.

However, given the vulnerability of the Australian economy, the downward adjustment could be very sharp and at any time which would involve a reduction to the 40 to 50 cent range to the United States dollar over a 6 to 12 month period. Such an adjustment may well trigger a crisis which would take the economy on a very different trajectory than what is being outlined here. In terms of the projection, if such a crisis was to occur it would seem logical to be around 2019 when a strong El Niño is projected to occur, as distinct from the weaker one predicted for 2014.

Figure 2.12: Exchange rate and trade weighted index



Population

There has been only marginal downward adjustment in the population growth rate. Currently, the net increase in the population is averaging a little below 100,000 per quarter. Due to the steadily deteriorating labour market, this quarterly increase is projected to decline by 84,000 by early 2016.

The high unemployment rates at the end of the projection period are expected to reduce the increase in the national population to less than 60,000 by the end of the projection period.

2.3 The Tasmanian outlook

2.3.1 Introduction

This section outlines the economic outlook for Tasmania to 2034-35, focussing on the short-term to 2018-19.

2.3.2 Summary of scenarios

Figure 2.13 shows the outlook for Tasmanian GSP growth over the period to 2034-35 for the Base, High and Low scenarios. Between 2013-14 and 2034-35 Tasmanian GSP growth is projected to average:

- 1.0 per cent per annum for the Base scenario;
- 1.5 per cent for the High scenario; and
- 0.5 per cent for the Low scenario.

Figure 2.13: Tasmanian GSP growth by scenario – 2007-08 to 2034-35

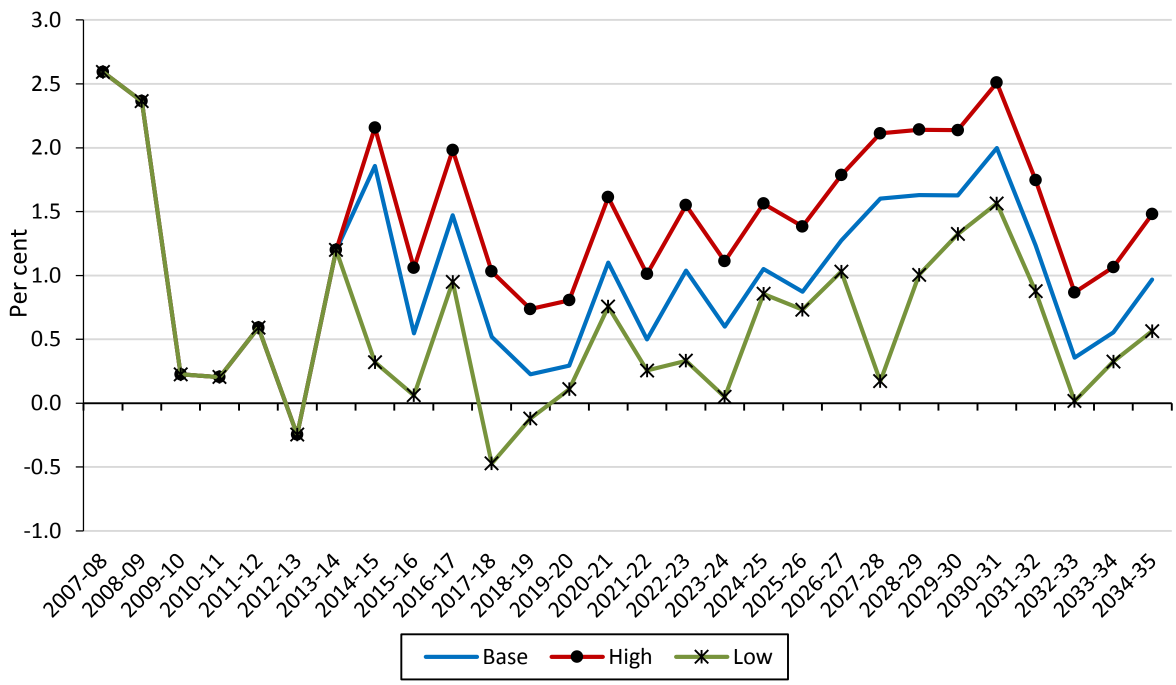


Table 2.3 shows the annual economic growth rates projected for Tasmania by scenario for the period 2007-08 to 2034-35.

Table 2.3	Tasmanian economic growth rate by scenario – 2007-08 to 2034-35		
	Base	High	Low
Per cent change			
2007-08	2.6	2.6	2.6
2008-09	2.4	2.4	2.4
2009-10	0.2	0.2	0.2
2010-11	0.2	0.2	0.2
2011-12	0.6	0.6	0.6
2012-13	-0.2	-0.2	-0.2
2013-14	1.2	1.2	1.2
2014-15	1.9	2.2	0.3
2015-16	0.5	1.1	0.1
2016-17	1.5	2.0	0.9
2017-18	0.5	1.0	-0.5
2018-19	0.2	0.7	-0.1
2019-20	0.3	0.8	0.1
2020-21	1.1	1.6	0.8
2021-22	0.5	1.0	0.3
2022-23	1.0	1.5	0.3
2023-24	0.6	1.1	0.0
2024-25	1.1	1.6	0.9
2025-26	0.9	1.4	0.7
2026-27	1.3	1.8	1.0
2027-28	1.6	2.1	0.2
2028-29	1.6	2.1	1.0
2029-30	1.6	2.1	1.3
2030-31	2.0	2.5	1.6
2031-32	1.2	1.7	0.9
2032-33	0.4	0.9	0.0
2033-34	0.6	1.1	0.3
2034-35	1.0	1.5	0.6
Average annual compound growth rates (per cent)			
2014-2025	0.8	1.3	0.3
2014-2035	1.0	1.5	0.5

2.3.3 The economic outlook for Tasmania to 2018-19

Table 2.4 presents selected economic aggregates for Tasmania to 2018-19 for the Base economic scenario.

Table 2.4 Macroeconomic aggregates and selected indicators – Tasmania (per cent change)

	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	Average annual growth rate 2013-14 to 2018-19
Household consumption expenditure	-2.2	0.7	2.8	2.9	3.5	1.6	2.5	0.4	2.3
Private dwelling investment	-6.2	-7.6	0.9	8.1	2.7	-1.0	2.3	-0.6	2.0
Total business investment	13.2	-20.4	5.1	6.6	7.7	4.5	-5.2	-5.2	2.3
Government consumption	3.2	1.6	-0.3	0.4	0.3	0.8	1.5	1.5	0.7
Public investment (excluding asset sales)	-15.2	-20.6	-1.9	11.5	9.6	3.5	7.7	4.0	5.8
State final demand	-0.8	-2.9	2.1	3.7	3.8	3.2	2.3	0.4	2.6
Gross state product at market prices	0.6	-0.2	1.2	1.9	0.5	1.5	0.5	0.2	1.0
Population	0.3	0.1	0.3	0.6	0.6	0.5	0.5	0.5	0.5
Total employment	-1.3	-1.0	-2.0	0.2	0.3	0.3	0.6	0.2	-0.1

Source: NIEIR and ABS.

Gross State Product (GSP)

Average Tasmanian GSP growth has been 0.7 per cent per annum between 2008-09 and 2013-14. Tasmanian GSP growth fell by 0.2 per cent in 2012-13 and rose by 1.2 per cent in 2013-14.

Weakness in the Tasmanian economy over the last few years has been driven by:

- falling private business investment expenditures;
- reductions in public sector capital expenditures; and
- relatively weak growth in private household expenditures.

Tasmanian GSP growth is forecast to average 1.0 per cent per annum over the 2013-14 to 2018-19 period. This is well below the actual recorded GSP growth rate of 14 per cent over the last 10 years, 2003-04 to 2013-14.

Population

Tasmania's rate of population growth has been slowing over recent years. In 2010-11, Tasmania's population increased by 0.7 per cent. By 2011-12, population growth was 0.3 per cent and in 2012-13 only 0.1 per cent. Growth in 2013-14 was 0.4 per cent.

The slowdown in Tasmania's population growth rate reflects the following:

- a fall in the natural increase in population (births less deaths); and
- significantly more net interstate emigration losses.

Net overseas migration gains have increased modestly over recent years to around 1,400 persons in 2012-13 and 1,300 in 2013-14. The rate of natural increase in population in Tasmania in 2012-13 was 1,590 persons, well below the 2,200 person increase in 2010-11. Tasmania's net interstate migration losses were 2,610 persons in 2011-12, 1,942 persons in 2012-13 and 1,279 in 2013-14.

Tasmania's population growth averages 0.5 per cent per annum between 2013-14 and 2018-19.

TABLE 2.5 INDICATORS ASSOCIATED WITH DEMAND PROJECTIONS – TASMANIA

	GROSS STATE PRODUCT	POPULATION	DWELLING STOCK	HOUSEHOLD DISPOSABLE INCOME
Unit	2012-13$M	'000	'000	2011-12$M
BASE				
2011	24526.00	507.67	230.93	19416.62
2012	24671.00	509.15	233.13	18924.00
2013	24610.00	509.66	234.70	18843.07
2014	24905.00	511.28	235.86	19050.08
2015	25367.46	514.23	236.98	19695.69
2016	25506.14	517.11	238.33	19938.32
2017	25881.24	519.72	239.79	20234.12
2018	26015.79	522.39	241.24	20546.98
2019	26074.43	525.15	242.80	20582.02
2020	26151.20	528.14	244.38	20913.39
2025	27291.69	541.51	252.21	22561.18
2030	29256.04	549.24	261.00	23995.46
2035	30779.55	558.10	267.84	25207.91
2040	31730.49	573.20	276.20	26766.40
2045	33114.30	587.71	285.06	28875.36
Percentage changes				
2014	1.20	0.32	0.50	1.10
2015	1.86	0.58	0.47	3.39
2016	0.55	0.56	0.57	1.23
2017	1.47	0.51	0.61	1.48
2018	0.52	0.51	0.61	1.55
2019	0.23	0.53	0.65	0.17
2020	0.29	0.57	0.65	1.61
Compound growth rate (per cent) -				
2014-2025	0.84	0.52	0.61	1.55
2020-2040	0.97	0.41	0.61	1.24
2014-2045	0.92	0.45	0.61	1.35
HIGH – Levels				
2015	25442.18	515.34	237.52	19753.79
2016	25711.33	518.62	239.07	20099.11
2017	26220.88	521.46	240.65	20501.05
2018	26491.24	524.50	242.28	20923.86
2019	26686.37	527.66	244.04	21067.54
2020	26901.36	531.04	245.82	21515.48
2025	28793.36	548.51	256.42	23806.87
2030	31651.73	561.01	268.30	25972.54
2035	34151.15	576.62	278.50	27989.36
2040	36109.82	594.18	288.23	30485.53
2045	38649.46	613.73	300.66	33732.22
Compound growth rate (per cent) -				
2014-2025	1.33	0.64	0.76	2.05
2020-2040	1.48	0.56	0.80	1.76
2014-2045	1.43	0.59	0.79	1.86
LOW – Levels				
2015	24984.70	513.31	236.52	19402.91
2016	25000.04	514.96	237.41	19547.77
2017	25237.44	516.71	238.57	19735.94
2018	25118.16	518.48	239.75	19845.21
2019	25087.72	520.33	240.95	19810.27
2020	25115.09	521.73	242.09	20092.50
2025	25683.44	527.84	246.89	21242.27
2030	26796.00	531.17	251.63	21985.86
2035	27701.66	536.12	254.41	22695.34
2040	27846.24	544.92	260.40	23501.96
2045	28476.39	551.29	265.55	24846.83
Compound growth rate (per cent) -				
2014-2025	0.28	0.29	0.42	1.00
2020-2040	0.52	0.22	0.37	0.79
2014-2045	0.43	0.24	0.38	0.86

All data are for the financial year ending in June of the year specified.

3. Electricity forecasting methodologies and modelling assumptions

This section outlines the methodologies employed and the key modelling assumptions used in developing Tasmanian electricity sales forecasts by class and maximum demands.

The centrepiece of the modelling methodology was the application of NIEIR's state and energy industry based economic energy projection models.

This section also outlines the key assumptions regarding cogeneration trends by scenario.

3.1 Methodology – electricity sales forecasts

TasNetworks, Tasmania, provided NIEIR with the following data:

- annual electricity sales for the top four major industrial customers for 1997-98 to October 2014;
- annual electricity sales for all its direct supplied industrial customers for 2008 to October 2014; and
- electricity sales estimates for 1999-00 to 2012-13 for Tasmania by customer class.

Historical estimates of electricity sales by class were obtained for the period 1969-70 to 1996-97 from the Energy Supply Association of Australia (ESAA) annual reports. These figures were reconciled with sales figures published in previous Hydro Tasmania and TasNetworks annual reports. Inconsistencies in the ESAA data from year to year in classifying sales by class were corrected using HEC annual report sales data.

Electricity sales data was obtained for the following customer classes:

- residential;
- direct connect industrial customers
- other industrial customers
- energy Intensive customers (top four customers); and
- public lighting.

Electricity demand at the customer terminal (end-use demand) was reconciled with total electricity generated.

The NIEIR forecasting model for Tasmania has always treated the top four major customers separately from other industrial load in Tasmania. The top four major customers are:

- Pacific Aluminium (Comalco);
- Norske Skog Mill (Fletcher Challenge Boyer);
- Temco; and
- Nyrstar (Zinifex).

These four major industrial customers account for around 40 per cent of the total Tasmanian winter MD.

Other small direct supplied customers were not previously modelled separately from other retail loads. From 2011 other small direct customers have been modelled separately from other retail industrial loads in Tasmania.

There are currently eight substations connected by small direct supplied customers in Tasmania. These include the following.

Direct connect customer name[2]	Station	Website
Temco	Temco (110 kV)	
Forestry Tasmania/Newood Energy	Huon River	http://www.southwoodresources.com.au/southwood/pages/project.html
Gunns (Bell Bay)	Starwood (110 kV)	
Mining & Manufacturing Group	Rosebery (44 kV)	http://www.mrt.tas.gov.au/portal/page?_pageid=35,831254&_dad=portal&_schema=PORTAL
Bell Bay Aluminium	Comalco (220 kV)	http://www.pacificaluminium.com.au
Copper Mines of Tasmania	Queenstown (11 kV)	http://www.cmt.com.au/
Gunns (Hampshire)	Hampshire (110 kV)	
Bass Metals (Que)	Que (22 kV)	http://www.bassmetals.com.au
Nystar (Risdon)	Risdon (11 kV)	http://www.nyrstar.com/Pages/default.aspx
Norske Skog	Boyer (6.6kV)	http://www.norskeskog.com/Business-units/Australasia/Norske-Skog-Boyer.aspx
Grange Resources (PL)	Port Latta (22 kV)	
Grange Resources (SR)	Savage River (22 kV)	

Notes:
1. Base Metals Hellyer Mill may be shut down, however, this remains uncertain.
2. Two small direct customers closed at Emu Bay and Wesley Vale.
3. Copper Mines of Tasmania shut-down in 2015.

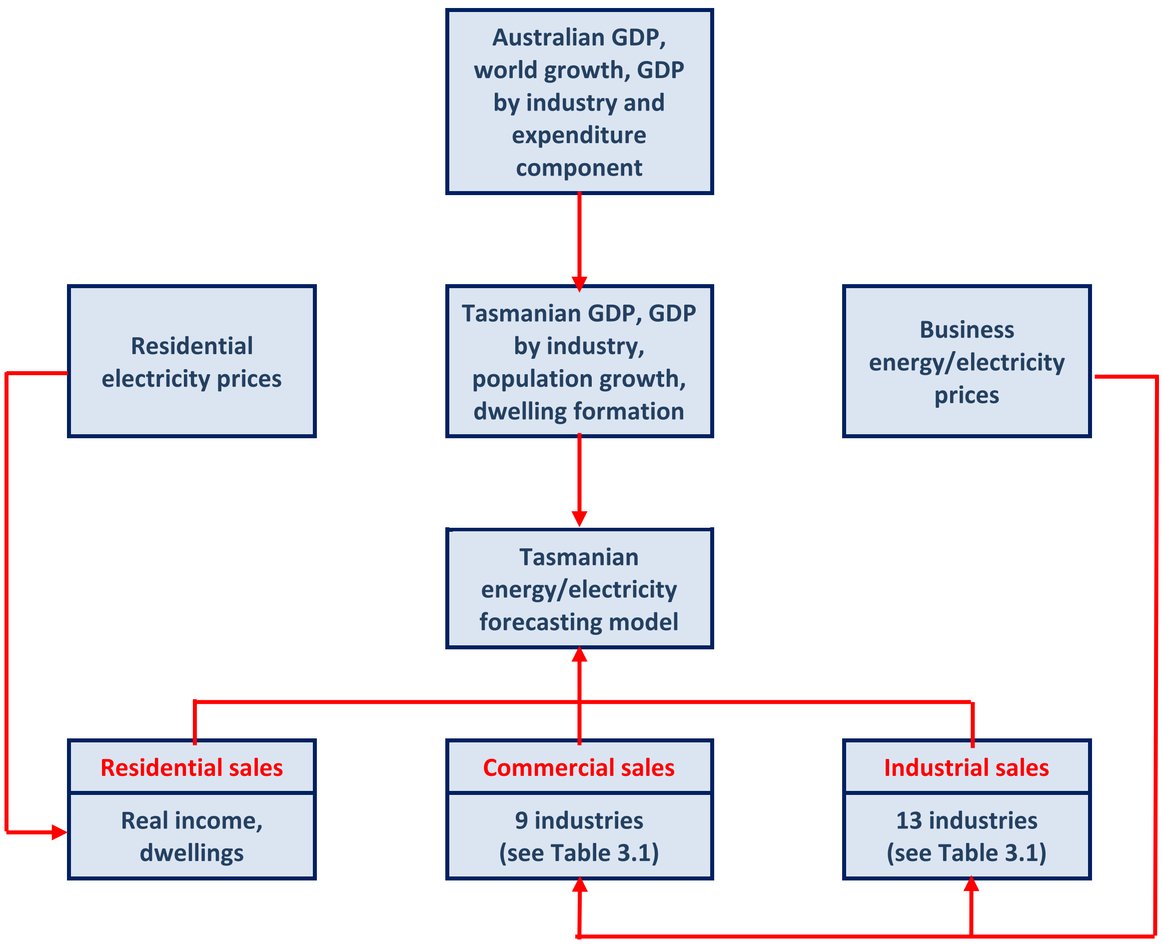
Many of Tasmania’s major customers and smaller direct supplied customers produce commodities that are exported. These companies therefore compete globally, although many are part of large multi-national mining and resource processing companies.

The forecasts for direct supplied customers in Tasmania take into account:

- known expansions or contractions in production;
- published company information on operations;
- historical electrical loads and contractual arrangements (where known); and
- the international and domestic economic outlook generally and possible effects on selected commodity markets and commodity prices.

Table 3.1 shows the Australian Standard Industrial Classification (ASIC) categories included in NIEIR’s Tasmanian electricity forecasting model. Table 3.1 also shows the concordance between customer class categories and ASIC industry categories. Electricity consumption forecasts are based on econometric models which link Tasmanian electricity sales by industry to real output growth by industry, electricity prices, and weather conditions. Business electricity sales in Tasmania are linked directly to business prices. Business sales are relatively inelastic to business prices, with a long-run own price elasticity of around -0.15. Business sales by industry (as shown in Table 3.1) are also linked to real output growth by industry for Tasmania. Residential sales are determined form a model including average consumption per dwelling, weather, real income, and electricity prices.

Figure 3.1: Schematic of energy/electricity forecasting model



The forecasts of Tasmanian electricity sales by class were therefore simply indexed to the sum of the relevant ASIC category forecasts. Electricity sales to Tasmania's four major industrial customers were treated separately, as well as TasNetworks direct supplied customers. NIEIR, with the assistance of Aurora Energy, developed alternative scenarios for electricity usage at these four major industrial customers and direct supplied customers, taking into account the prospects for the industry concerned and existing contracts.

In the case of each of the scenarios developed, additional exogenous load was assumed from these four major customers and direct supplied customers, as a proxy measure for new or greenfields load. The additional loads for some customers in Tasmania, therefore, do not reflect load at that site in particular, but a more general assumption of some major additional industry loads being secured by Tasmania.

Table 3.1	Reconciliation of customer class categories with ASIC industries
Customer class category	**ASIC**
Residential	
Commercial	Water and sewerage Construction Wholesale and retail trade Transport and storage Communication Finance, property, business services Public administration and defence Community services Recreation, personal and other services
Industrial	Agriculture, forestry, fishing, hunting Mining Food, beverages, tobacco manufacturing Textiles, clothing and footwear manufacturing Wood, wood products manufacturing Chemicals, petroleum, coal manufacturing Paper, paper products manufacturing Non-metallic minerals manufacturing Basic metal products manufacturing Fabricated metal products manufacturing Transport equipment manufacturing Other machinery and equipment manufacturing Miscellaneous manufacturing

Notes: ASIC refers to Australian Standard Industrial Classification.

1. The farm class which excludes residential farm is included in the industrial sector.

3.2 Methodology – forecasts for system maximum demand

As indicated later in this section, forecasts of winter and summer MDs for Tasmania are partly driven by AEMO's inputs, such as Tasmanian GSP growth.

Forecasts of summer and winter maximum demands for Tasmania were developed using econometric regression equations based on data supplied by TasNetworks. In broad terms, these relationships (equations) relate the ratio of maximum demands to energy to average temperature at system maximum demand (MD).

The definition of maximum demand is different from the basis used for energy sales. System Maximum Demand is the maximum half hour average Tasmanian system requirement at generator connection points. This demand for the relevant half hour, expressed as an average power comprises:

- total Tasmanian end-use sales;
- transmission and distribution losses; and

excluding:

- buyback (supplying sales) from cogeneration/generation embedded in the distribution network; and
- own use supplying load directly from cogeneration/generation embedded in the distribution network (i.e. not drawn from network and not sales).

TasNetworks provided NIEIR with the following data:

- half hourly demands at generators for the period 1987-88 to October 2014 (MW); and
- maximum demands of the direct supplied industrial customers at system MD (MW);

The relationships between Tasmanian MDs, energy and weather conditions were estimated excluding the impact of the top four major industrial customers which are assumed to be weather/temperature insensitive. When sufficient historical data becomes available for the other direct supplied customers (15 years), these will be incorporated into the forecast equation for Tasmanian MDs.

Since 2011, the forecasting model was expanded to cover a number of smaller transmissions or direct connect TasNetworks customers.

The existing model treated the top four industrial customers as major load. These include:

- Pacific Aluminium Bell Bay Aluminium;
- Nyrstar Hobart Zinc Smelter;
- Norske Skog Boyer Mill (paper);
- BHP Billiton, Temco (Manganese); and
- Gunns Pulp Mill (proposed not operational).

The model includes 10 additional connection points with the following direct connect customers on the TasNetworks network (two have since closed operations). These include:

- Hampshire – Gunns;
- Port Latta – Grange Resources;
- Que – Base Metals Hellyer Mill;

- Queenstown – Copper Mines of Tasmania;
- Rosebery – Zinifex Rosebery Mine;
- Savage River – Grange Resources;
- Starwood – Gunns Bell Bay; and
- Huon River – Tasmanian Forests.

In terms of maximum demands, both non-coincident and coincident peaks were calculated for both summer and winter MDs for each of the 4 major industrials and the 10 direct connect small majors.

Table 3.2 shows diversity factors between the peak demand of each customer and the Tasmanian summer and winter peak.

Table 3.2 Diversity factors at Tasmanian system MD for large and small industrials

		Winter	Summer
Rio Tinto	Bell Bay	0.9929	0.9883
Norske Skog Mill	Boyer Substation 6.6 kV	0.9259	0.9231
Temco	BHP Billiton	0.8779	0.8895
Zinifex	Nyrstar (Risdon Substation 11 kV)	0.9137	0.9111
Gunns Mill	Proposal only	0.9500	0.9500
Hampshire Substation 110kV	Gunns	0.1863	0.3635
Port Latta	Grange Resources Tas	0.7842	0.7504
Que Substation 22kV	Intec Hellyer	0.2883	0.6038
Queenstown Substation 11kV	Copper Mines of Tasmania	0.4010	0.4891
Rosebery Substation 44kV	Mining & Manufacturing Group Rosebery	0.8699	0.8201
Savage River	Grange Resources Tas	0.9300	0.8795
Starwood Substation 110kV	Forest Enterprises Australia	0.6379	0.7147
Huon River Substation 11kV	Forests Tasmania	0.6140	0.7395

Notes: Calculated from to top five coincidence factors for the last three years. For summer 2011-12, 2012-13 and 2013-14. For winter 2010, 2011 and 2012.
For Temco the average of the last two years was used, as Temco's load was at a 'low level' during winter 2012.

Temperature percentiles for winter and summer

NIEIR undertook a detailed analysis of temperature data for Tasmania for the last 50 years in order to estimate the probabilities of alternative winter and summer temperatures. These calculations take into account warming trends within the data.

Daily electricity maximum demand in winter and summer depends on:

- the ambient minimum temperature during the day; and
- the ambient maximum temperature on the previous day.

NIEIR's approach was to calculate the probabilities associated with different average daily temperatures. The average temperature was defined as the weighted average of the overnight minimum and the previous daily maximum. The daily minimum was assigned a weight of 0.8, while the previous day's maximum a weight of 0.2 in this calculation. Tasmanian maximum demands typically occur around 9:00 a.m., although in recent years evening peaks are increasingly occurring.

NIEIR undertook to calculate the following temperature percentiles for maximum demand forecasts:

- 10th percentile: temperature met once in every ten years;
- 50th percentile: temperature met once in every two years; and
- 90th percentile: temperature met nine out of ten years.

All percentile calculations are only based on maximum and minimum temperatures. Temperature exercises the most important influence on peak demands. Other weather variables, such as humidity, rainfall and wind, were not considered in the POE calculations for Tasmania.

NIEIR updated the summer and winter percentiles for the 2014 TasNetworks report. NIEIR also re-computed various percentiles depending upon whether a warming trend is included or not and whether weekends are excluded or not.

The temperature percentiles used for Tasmania are contained in column (2) of Table 3.3.

Table 3.3 Summer and winter percentiles for lowest average temperature days[1]

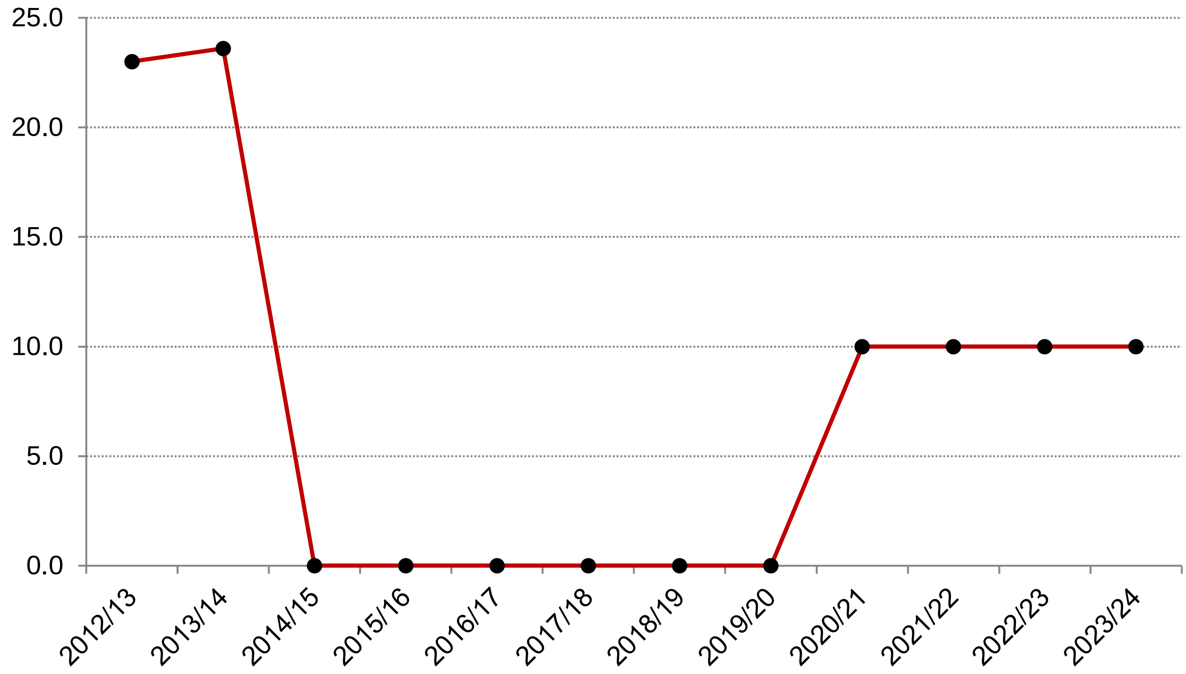
	(1) Warming trend weekends excluded	(2) No warming trend weekends excluded
Winter		
10th percentile	1.5	0.9
50th percentile	2.7	2.1
90th percentile	3.6	3.2
Summer (holidays included)		
10th percentile	7.0	7.0
50th percentile	8.7	8.7
90th percentile	9.3	9.2
Summer (holidays excluded)		
10th percentile	7.0	7.0
50th percentile	8.7	8.7
90th percentile	9.8	9.8

Note: 1. Based on 1970 to 2014 temperature data. Summer is December to mid-March, excluding holiday period 20 December to 20 January. Winter is June to August.

3.3 Carbon (CO_2e) pricing impacts

Carbon pricing will increase the prices of electricity and gas according to the CO_2e price and the CO_2e content of fuels used to produce electricity. The carbon content of gas used to provide end-use energy services results in increased end-use gas prices. In end-use markets energy users will respond to increased energy prices by reducing energy demand, particularly in the longer term when energy using equipment can be changed. Carbon pricing also changes the generation mix required to balance demand and supply towards gas and renewables.

Figure 3.2: Real carbon price ($2012)



The CO_2e price is $23/t from 2012-13 to 2013-14.

The demand response, that is, the price elasticity of demand for electricity, is estimated to be about -0.3 in the long-run. High real price increases such as the ones that have occurred in Australia over recent years could engender a short-run response close to the long-run elasticity, or even greater.

From an electricity demand viewpoint, the focus of electricity retailers on CO_2e pricing impacts will be on the following.

(i) CO_2e pricing will increase electricity prices and reduce demands compared with no carbon pricing.

(ii) Gas prices will also rise and accordingly gas versus electricity competition may not be significantly affected.

After the Federal Government removed the carbon tax in July 2013-14, electricity and gas prices may still rise as a result of Opposition climate change policies. The impact, however, is indeterminate at this time. In this projection carbon pricing is re-introduced in 2020-21.

Table 3.4 Real electricity prices – Tasmania (2009-10 prices)	Residential	Business	Total
2009-10	17.2	7.0	9.1
2010-11	18.6	7.6	9.8
2011-12	21.0	8.5	11.1
2012-13	22.9	9.3	12.1
2013-14	22.5	9.6	12.2
2014-15	21.1	8.5	11.1
2015-16	23.2	11.0	13.5
2016-17	23.1	11.3	13.7
2017-18	23.2	11.5	13.9
2018-19	22.5	10.7	13.2
2019-20	22.1	10.4	12.8
2020-21	22.9	11.2	13.6
2021-22	22.8	11.3	13.7
2022-23	22.8	11.4	13.7
2023-24	22.5	11.2	13.5
2024-25	22.5	11.2	13.5
2025-26	22.5	11.3	13.6
2026-27	22.6	11.4	13.7
2027-28	22.6	11.4	13.7
2028-29	22.7	11.5	13.8
2029-30	22.3	11.1	13.4
2030-31	22.3	11.2	13.5
2031-32	22.4	11.2	13.5
2032-33	22.4	11.3	13.6
2033-34	22.3	11.4	13.6
2034-35	22.3	11.4	13.6

[redacted]

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[redacted]

3.5 An assessment of the temperature sensitivity of Tasmanian daily demands

The section has been prepared with the objective of improving the accuracy of the peak electricity demand forecasts by directly modelling daily half hour electricity maximum demands with weighted average daily temperatures.

Table 3.9 shows the temperature sensitivity of Tasmanian load for summer and winter for typical times when the Tasmanian electricity supply system peaks. Table 3.9 indicates that the temperature sensitivity is increasing over time, although it jumps around depending on how cold each winter actually is overall (i.e. the seasonal average temperature).

For summer, as indicated in Table 3.9, the sensitivity is around 12-15 MW per degree. For winter, the sensitivity in Table 3.9 is around 25-30 MW per degree. These sensitivities depend upon how cool each winter actually is.

Table 3.9 Temperature sensitivity summer and winter MDs, per degree Celsius

		2007	2008	2009	2010	2011	2012	2013	2014
Summer									
TasNetworks demand	[7:00 AM]	6.7	8.9	17.3	12.8	15.3	11.6	5.0	11.7
TasNetworks demand LESS majors	[7:00 AM]	8.3	8.7	16.2	11.8	13.4	7.8	2.7	8.9
Winter									
TasNetworks demand	[8:30 AM]	25.6	29.3	21.3	17.8	21.8	27.5	24.4	20.3
TasNetworks demand LESS majors	[8:30 AM]	27.0	30.5	22.1	21.7	22.6	26.8	23.5	18.2

The winter MD forecast equation

For each year of the TasNetworks updates, the actual winter MD forecast equation was re-estimated. The winter MD equation is estimated as a load factor equation. That is, the ratio of the winter MD to actual total annual energy. The dependant variable in the 2014 equation was estimated in two stages. The first equation estimates a time trend for the ratio of winter MD to energy. The second stage uses the difference from the time trend as the dependent variable, and includes other relevant explanatory variables. Loads and energies for the top four industrial customers are excluded from this equation. Loads from small major direct supplied customers are included in the estimated equation (since sufficient historical data is not yet available). In terms of the forecasts, however, loads from direct supplied customers are treated separately.

By linking the winter MD forecast for Tasmania to energy, it ensures consistency between the energy and the demand projections. Load factor equations for maximum demand modelling have historically been used quite extensively, including for VENCorp, Powerlink, TransGrid and ESIPC (and its predecessors) throughout the 1990s and early 2000 decade.

The energy projections for Tasmania reflect the sectoral composition of gross state product growth as well as the impact of changes in real electricity prices and other policy drives of the energy projections. The load factor equation effectively means the forecast winter MDs for Tasmania indirectly reflect the impact of GSP and real electricity price changes.

The winter MD equation also includes Tasmanian GSP as an independent explanatory variable. Its sign suggests that the faster the growth in GSP, the faster the growth in the ratio of the winter MD to total energy. For the 2014 update GSP has a small positive impact.

A price variable is very difficult to justify in any MD forecast equation until customers are interval metered and/or face peak power pricing/tariff structures. Price was included as an independent variable, but note that the estimated coefficient on real prices is statistically insignificant. The estimated equation is provided below.

$$MDw/E_t - MDw/E\,(t) = \underset{(-0.1)}{-0.0024} + \underset{(3.4)}{0.0022}\,TempW + \underset{(0.5)}{0.0003}\,GSP + \underset{(3.4)}{0.0082}\,D_1 + \underset{(3.4)}{0.0105}\,D_2 - \underset{(-1.3)}{0.0268}\,P$$

$\bar{R}^2 = 0.75$

Where:

MDw/E_t	=	the ratio of winter maximum demand and total annual energy at time t.
MDw/E (t)	=	the predicted MDw/E from the time trend model at time t.
MDw	=	winter maximum demand, excluding top four industrial customers.
E	=	total generated energy, excluding top four individual customers.
TempW	=	18- weighted average temperature of minimum from day of winter peak (0.8) and yesterday's maximum (0.2).
GSP	=	percentage change in State GSP.
D_1	=	dummy variable for winter 2004 and winter 2005 (used to remove the abnormal spikes in 2004 and 2005).
D_2	=	dummy variable for winter 2011 and 2012 (to account for structural change)
and MDw	=	$E * (-0.0024 + 0.0022\,TempW + 0.0003\,GSP + 0.0082\,D_1 + 0.0105 D_2 - 0.0268\,P + MDw/E\,(t))$.

t statistics are shown in parenthesis.

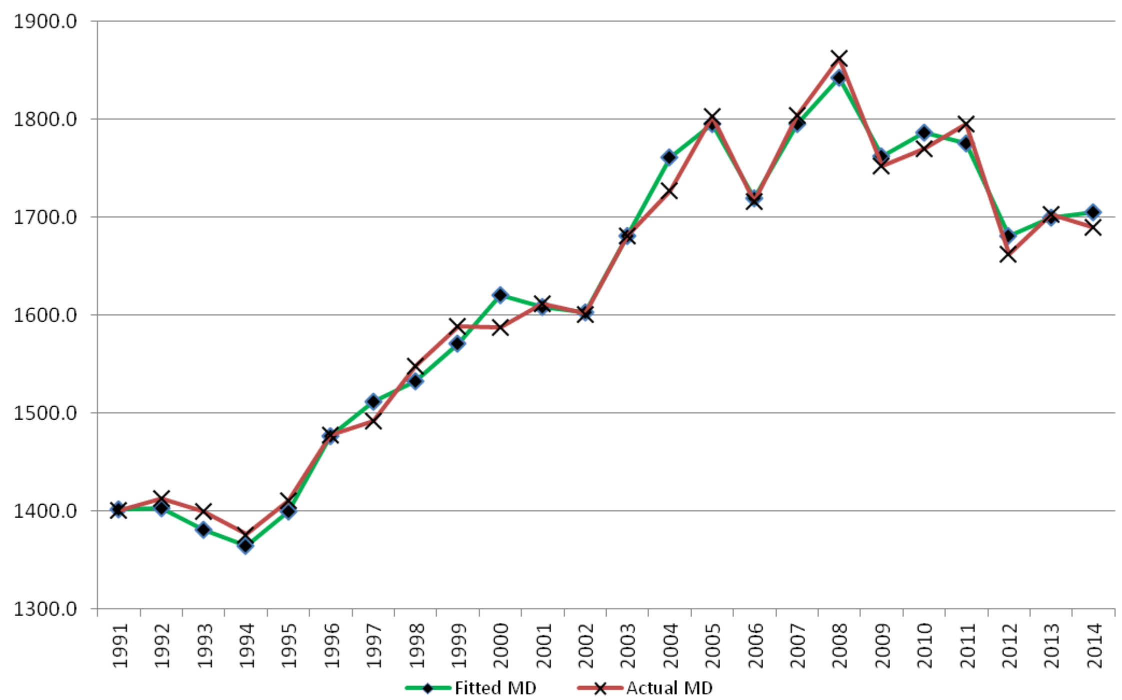
The low level of significance for GSP suggests its direct impact on peak demand is weak. Temperature has a significant impact on winter maximum demand, suggesting colder days are associated with increased maximum demand.

Table 3.10 shows the actual and fitted winter MD over the period 1994 to 2014. Fitted values are the values predicted by a model fitted to a set of data. These values include the load of the top four major industrial customers. This implies that the load at the top four individual customers is known. Load at these customers is currently around 600 MW. These loads are analysed separately in this section.

Figure 3.7 shows actual and fitted winter maximum demands over the period 1991 to 2014.

Table 3.10	Actual and fitted winter maximum demands – 1994 to 2014			
	10th	50th	90th	Actual
1994	1563.5	1501.3	1432.2	1376.0
1995	1583.8	1521.4	1452.0	1411.0
1996	1604.0	1541.5	1471.9	1478.0
1997	1624.3	1561.6	1491.8	1492.0
1998	1644.6	1581.7	1511.7	1548.0
1999	1664.9	1601.8	1531.6	1588.3
2000	1685.1	1621.9	1551.5	1587.4
2001	1705.4	1642.0	1571.3	1612.1
2002	1725.7	1662.1	1591.2	1601.3
2003	1746.0	1682.2	1611.1	1680.6
2004	1766.2	1702.3	1631.0	1726.9
2005	1786.5	1722.4	1650.9	1802.6
2006	1806.8	1742.5	1670.8	1716.1
2007	1827.1	1762.6	1690.6	1803.5
2008	1847.3	1782.7	1710.5	1862.1
2009	1867.6	1802.8	1730.4	1752.6
2010	1887.9	1822.9	1750.3	1770.2
2011	1908.2	1843.0	1770.2	1794.8
2012	1778.5	1713.1	1640.1	1662.4
2013	1798.7	1733.2	1659.9	1703.1
2014	1819.0	1753.3	1679.8	1704.1

Figure 3.7: Actual and fitted winter maximum demands (MDs) – 1991 to 2014



As indicated in Table 3.10, the forecast error ranges up to 2.0 per cent for the historical period. This forecast error assumes load at the top four industrial customers is known. A 30 MW to 40 MW forecast error at the major industrials would increase the forecast error by a further 1.0 per cent. Additional error statistics are tabulated in Appendix C.

A similar forecasting equation was estimated for the summer generated maximum demand. The summer peak for Tasmania typically occurs between 7:00 and 8:30 a.m. on a cold summer weekday. The equation below was estimated in 2006. The summer MD equation has been re-estimated a number of times using alternative functional forms and variable definitions, but still, unsatisfactory and implausible empirical results were obtained.

$$MDs/E = \underset{(16.6)}{0.159} - \underset{(-1.7)}{0.0015}\ TempS + \underset{(1.0)}{0.0002}\ GSP - \underset{(-0.6)}{0.005}\ DUM \qquad \bar{R}^2 = 0.29$$

Where:

MDs = summer maximum demand, excluding top four industrial customers.

E = total generated energy, excluding top four individual customers.

TempS = weighted average temperature of minimum from day of summer peak (0.8) and yesterday's maximum (0.2).

GSP = percentage change in Tasmanian GSP.

DUM = dummy variable for winter 1999.

t statistics are shown in parenthesis.

As indicated above, the fit for the summer MD equation was relatively poor. In any case, the coefficient on temperature is not significantly different from the coefficient on the winter MD equation. What all this suggests is that there is significantly more non-weather related viability in the summer MDs and that the relationship with temperature is similar to the winter MD equation. Unstable irrigation loads could partly explain this instability.

3.6 Time profile of winter maximum demands

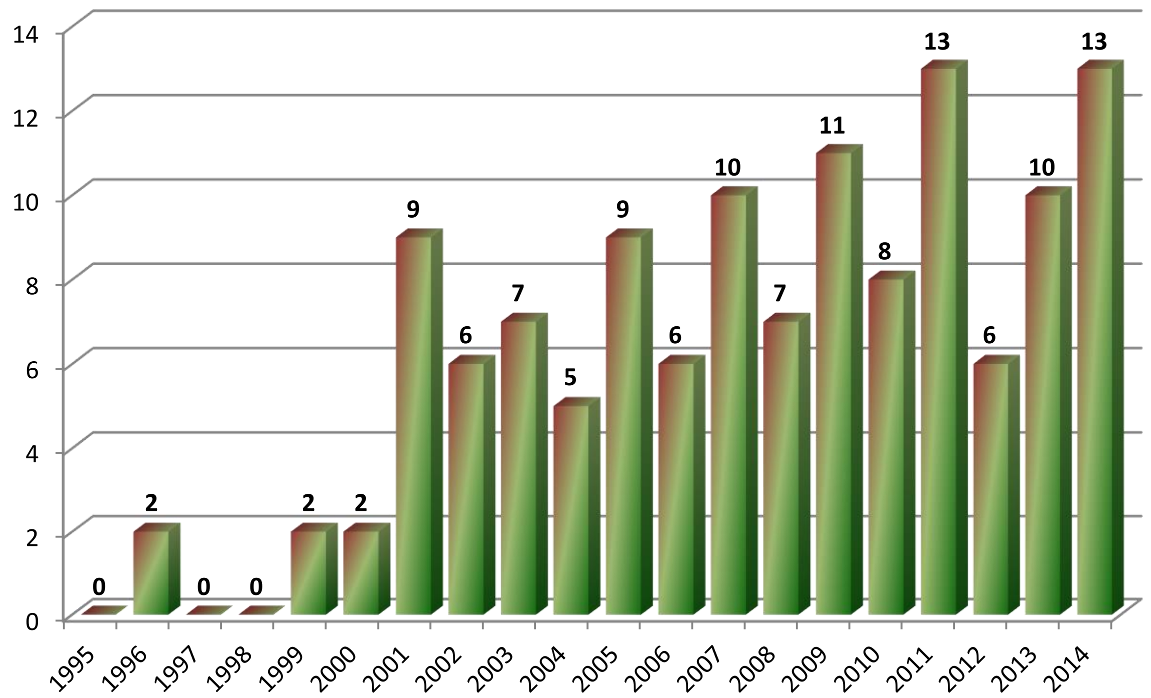
Tasmania has traditionally experienced a morning system peak demand. However, analysis suggests there has been a shift in the time profile of peak demands from morning to the afternoon, when particular climatic conditions prevail. Vis-à-vis, if the daily maximum temperature falls below 10°C there is a high probability of an afternoon peak.

Half hourly system demands by generation for winter (June, July and August) between 1987 and 2013 were examined. Weekends and public holidays were removed from the data set. The top 30 daily maximums for each winter were extracted. Between 1987 and 1998 there was no marked shift in the time profile of daily system peak demands, with the exception of 1996 where two afternoon peaks were observed. However, in 1999 and 2000, two of the top thirty system peeks occurred in the afternoon, when the maximum temperature was below 10°C. The number of afternoon peaks increased to 9 out of 30 in 2001 and 6 out of 30 in 2002. In 2004, 5 of the top 30 were evening peaks. There were nine again in winter 2005 and six in 2006. In both 2004 and 2005, out of all 66 daily winter weekday MDs (and not the top 30), 22 were evening peaks.

In 2009 there were 11 evening peaks in the top 30, following 7 in 2008. There were 8 in winter 2010 and 13 in 2011. There were an equal high 13 evening peaks in 2014.

In 2012 NIEIR attempted to re-estimate the winter MD equations allowing for both morning and evening peaks. The evening model, however, proved quite unstable and unsatisfactory regression results were obtained. NIEIR will examine alternative specifications in the future, including the Peak Sim approach.

Figure 3.8: Tasmanian winter maximum demands
Tasmanian top 30 system peaks – number of evening peaks



3.7 The impact of gas supply on electricity sales

Tasmania's energy supply sector has undergone a process of significant upgrading since 2000. These include:

- the development of significant renewable energy sources of power (e.g. wind and hydro) mainly reflecting MRET and RET;
- the construction of the Basslink interconnector linking the NEM to the Tasmanian interconnected power system; and
- the introduction of natural gas supplies to Tasmania and the gradual roll-out of gas distribution and reticulation infrastructure.

The take-up of natural gas by Tasmanian households has been relatively slow. This is because the costs of conversion, or the early scrappage of electrical or wood using technologies for space or are heating is not economic. Where the roll-out extends past new housing developments, the uptake of natural gas could be around 40 to 50 per cent.

In March 2009 Powerco changed its business name to Tas Gas Networks. By August 2009, a total of 6,500 customers in Tasmania were connected to the distribution system, including 500 companies and 50 large industries. Customer numbers were estimated to be around 8,400 by 2012.

For residential customers, Aurora Energy tariffs in 2014 are currently:

- fixed charge 21.5 cents/day – $78.48/annum; and
- variable charge $31.90/GJ.

Tas Gas Networks also charges a $300 connection fee (as at January 2013).

Natural gas

NIEIR's Tasmanian energy model includes an industry based gas projection model.

In terms of gas penetration into Tasmanian commercial and industrial industries, the gas penetration is assumed to increase from around zero in 2005 to around 40 per cent of the implied Victorian gas intensity by industry. This implies that the gas intensity per unit of output in Tasmania will gradually increase to up to 40 per cent of the Victorian intensity (Victoria has a mature gas market).

Gas penetration into the Tasmanian industrial/commercial sectors would typically occur in the following end-uses:

- commercial and industrial boilers;
- industrial kilns;
- cogeneration; and
- commercial and industrial cooking.

For the residential sector, new gas connections are determined from:

- 24 per cent of new dwellings; and
- 0.5 per cent of existing dwellings.

The take-up of natural gas in Tasmania has been relatively slow compared to initial expectations.

3.8 The contribution of non-scheduled generation and wind

The contribution of wind and embedded generation (hydroelectric) was re-assessed in 2014. There is limited historical data to make an accurate or probabilistic assessment.

Non-scheduled hydro in Tasmania includes the following:

- Rowallan;
- Repulse
- Cluny;
- Butlers Gorge; and
- Paloona.

In terms of energy, the contribution of non-scheduled hydro was assessed at 431 GWh. This represents the average of two normal years and two drought years.

The contribution of wind to energy was assumed to be 35.7 per cent. (Capacity factor applied to capacity in place.)

In the absence of extensive data, the contribution of non-scheduled hydroelectric generation was assessed by identifying the actual contribution by these generators in the top five peaks over the last five years.

For winter, averaging all these implies a contribution of 65.8 MW for winter and 37.5 MW for summer for non-scheduled hydro in Tasmania. The winter calculation uses 2012, 2013 and 2014 winters while the summer calculation used summers 2011-12, 2012-13 and 2013-14. The contribution of wind energy to summer and winter peaks is assumed to be zero. This may be revised in 2014.

3.9 Assumed price elasticity for Tasmania and how it will contribute to the forecast model

The Tasmanian electricity model includes price elasticities by industry. The long-run own price elasticities of demand are as follows:

Residential	-0.25
Commercial	-0.20
Industrial	-0.30.

These price elasticities only apply to retail, commercial and industrial loads. TasNetworks' direct supply customers are treated on a customer by customer basis and do not include price effects.

The long run price elasticity implies effects over 15-20 years. In practice, most of the effect has occurred by year 4 or 5. The -0.25 for residential and above implies that a 10 per cent increase in residential prices will reduce residential sales by 2.5 per cent.

3.10 A summary of the impact of greenhouse policy on Tasmania

The impact of greenhouse policy on Tasmania is presented below. The assumptions for electricity prices and carbon are presented in Section 3.3.

Energy/Greenhouse policy	Timing	Quantitative impacts	Uncertainties
Clean Energy Future	1 July 2012 – 1 July 2014	Price impact \$23/t CO_2e	Energy intensive industries.
Direct Action Plan	2014	Uncertain	Actual emissions reduction.
Climate Smart Tasmania 2013: A 2020 Climate Change Strategy	2013	Projected 100% net renewable energy capacity by 2020 (up from 87%) 35% reduction in CO_2 emissions from 1990 levels by 2020	
Renewable energy			
Feed-in-Tariff (Tasmania)	Ongoing	28¢/kWh up to 10 kW (pre-existing customers until 2019) 8¢/kWh new customers from Aug, 2013 to Dec 2013. Regulated rate set by independent Tasmanian Economic Regulator from 1 Jan 2014.	Length of scheme price
Renewable Energy Target	2011 onwards	Retail prices rise 2010-2015 +4.4% 2016-2020 +5.4% 2021-2030 +3.7%	Price of RECs impact of HW. Program continuation and scope. RET currently under review.
Demand management			
Smart Meters (Tasmania)	Not proposed	Nil	
Solar Cities Program	None	None	Tasmania not included
Smart Grids (Tasmania)	Not proposed.	None	
Energy Efficiency Opportunities Program	1 July 2006 – 21 June 2014	Large energy users in Tasmania > 0.5 PJs	Continuation of program from July 1, 2014
6-Star Building energy efficiency rating	1 May 2013	Efficiency standards for new homes and extensions.	Compliance
Appliances MEPs	Ongoing	Australia only	Dumping of non-compliant appliances
Electric HW Phase Out	2010-2012 staged	Australia only, energy only	Tasmania not participating
Incandescent light bulb phase out (MEPS)	2009 commenced	Australia and energy only	Market share of compliant halogen lights
State based Energy Efficiency Scheme (Tasmania)	Not proposed		
Electric cars	2012 onwards	Low uptake	Battery technology
State Renewable Energy Strategy		Emission reduction strategies with the State's largest emitters. Convert coal combustion to natural gas.	

4. Tasmanian electrical energy forecasts to 2045

This section presents electricity demand forecasts by class and electricity generated for the Tasmanian distribution region to 2045. Projections to 2045 are provided in Appendix D. The commentary in this section focuses on the outlook to 2025. The methodology for developing the Tasmanian energy projections was presented in Section 3.1.

Three scenarios were developed, a base, high and low growth scenario. The economic and industry projections associated with these scenarios were outlined in Section 2. The methodology and modelling assumptions relating to electricity sales were outlined in Section 3. The commentary focuses on the period to 2024-25.

The contribution of non-scheduled and wind generation to Tasmanian energy generated needs to be deducted from total energy generated (to meet all Tasmanian end-use demands and losses) to obtain scheduled Tasmanian generation.

For energy, non-scheduled hydro-electric generation are assumed to contribute 430 GWh to annual generation. This is based on average generation by these hydro generators over two normal years and two drought years. Non-scheduled wind generators were assumed to contribute to energy assuming an overall average capacity utilisation rate of 35.7 per cent. Table 4.1 shows the forecast total generation, both including and excluding non-scheduled generation.

4.1 Electricity sales by customer class

The base scenario

Under the base scenario, Tasmanian gross state product grows by 0.8 per cent in average terms between 2014 and 2025. Population growth averages 0.5 per cent per annum over the same period.

Table 4.1 presents electricity sales projections by major class for Tasmania to 2045. Figures 4.1 to 4.4 show the total growth and growth by major class and scenario between 2005 and 2025. Total electricity sales growth averages 0.9 per cent per annum between 2014 and 2025.

The main movements by class in the base scenario are as follows.

- A general feature of the energy projection for residential, commercial and industrial is the impact of the price increases on sales growth.
- Growth in the residential market has been relatively flat over the last decade. The extension of the gas distribution and reticulation network leads to a very small but gradual loss of heating load (both space and water). Residential sales remain relatively flat in absolute terms between 2014 and 2025. Residential electricity sales in Tasmania rise by 0.7 per cent between 2014 and 2025.
- Commercial sales growth over the 2014 to 2025 period is partly dampened by the substitution of natural gas for electricity in area heating and hot water, as well as cooking. Commercial sector sales growth averages 2.4 per cent per annum between 2014 and 2025.
- Industrial sales in Tasmania fell by 1.2 per cent in 2010-11 and fell by 3.2 per cent in 2011-12. Small majors fell 34 per cent in 2010-11, mainly reflecting load loss at Emu Bay and Wesley Vale. Industrial energy, excluding major load, rises by 0.9 per cent per annum between 2014 and 2025. Major industrial customer sales have increased, on average, by 1.0 per cent per annum over the last 10 years in Tasmania. The forecasts for industrial load include additional

new, or expansions in existing, load consistent with history. These are relatively small and can be seen in 2016-17 and 2021-22.

- Major load energy (top four industrials) fell by 4.4 per cent in 2011-12 and rose by 2.2 per cent in 2012-13. Major load fell by 1.1 per cent in 2013-14 but is forecast to increase by 2.2 per cent in 2014-15.
- Public lighting electricity sales are linked to general population growth. Public lighting is forecast to grow at an average annual rate of 2.7 per cent between 2014 and 2025.

The high scenario

Under the high growth scenario, Tasmania's gross state product increases by an average annual rate of 1.3 per cent between 2014 and 2025. Population growth averages 0.4 per cent per annum over the same period.

The key features of the high scenario in terms of electricity sales are:

- total electricity sales growth averaging 1.9 per cent per annum between 2014 and 2025, 1.0 percentage point above the base scenario;
- average residential sales growth of 1.6 per cent per annum between 2014 and 2025, reflecting stronger dwelling formation;
- commercial sales growth averaging 3.5 per cent per annum between 2014 and 2025, 1.1 percentage points above the average base projection; and
- industrial sales growth of 1.7 per cent per annum on average between 2014 and 2025, partly reflecting more rapid growth in energy intensive industries and downstream processing of primary food products.

The low scenario

Under the low scenario, Tasmania's gross state product increases at an average annual rate of 0.3 per cent, 0.5 percentage points below the base projection. Average annual population growth between 2014 and 2025 is 0.3 per cent per annum, 0.2 percentage points below the base scenario.

The key features of the low scenario in terms of electricity sales are:

- average annual residential sales rising by 0.4 per cent per annum between 2014 and 2025, reflecting slower growth in the dwelling stock and the impact of gas reticulation;
- comparatively slow growth in commercial sales, which average 1.4 per cent per annum between 2014 and 2025, 1.0 percentage point below the average growth under the base scenario;
- industrial sales fall by an average rate of 0.6 per cent between 2014 and 2025, reflecting much slower growth in manufacturing output generally for Tasmania and the loss of some industrial load. TEMCO is assumed to close in 2019-20 under the low scenario; and
- total average sales across all classes falling by 0.8 per cent between 2014 and 2025, 1.7 percentage points below the base projection.

Figure 4.1: Tasmanian electricity sales by class – total
Base, high and low scenarios

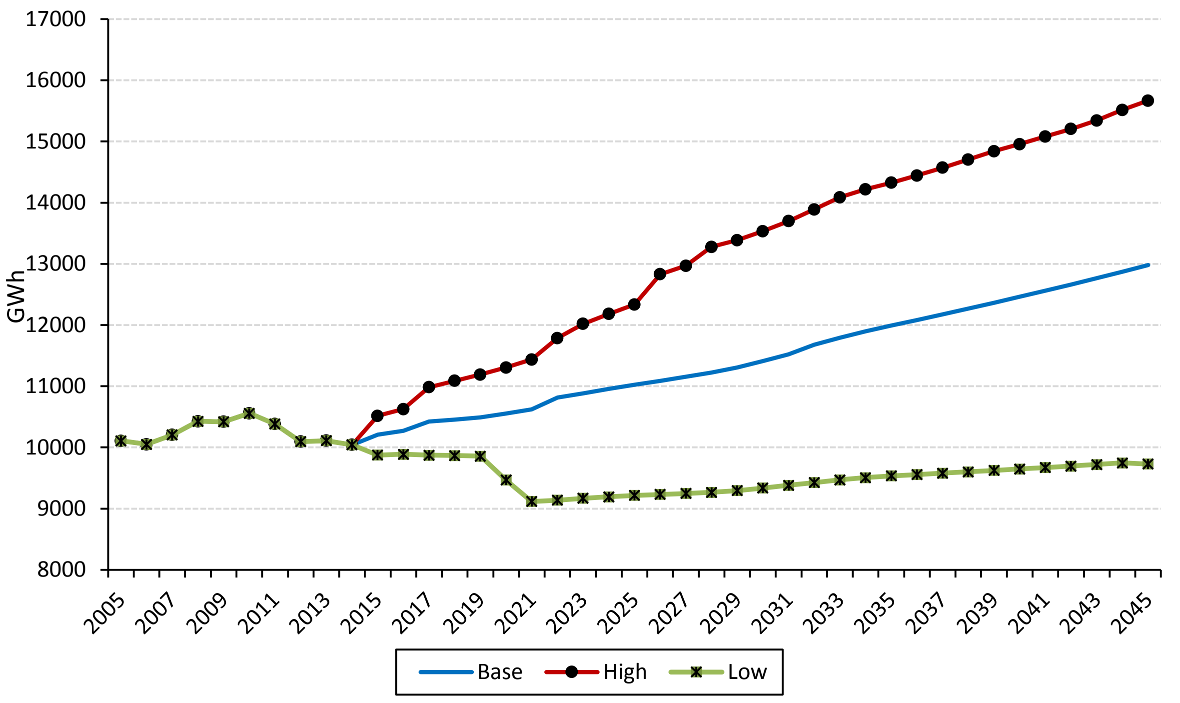


Figure 4.2: Tasmanian electricity sales by class – residential
Base, high and low scenarios

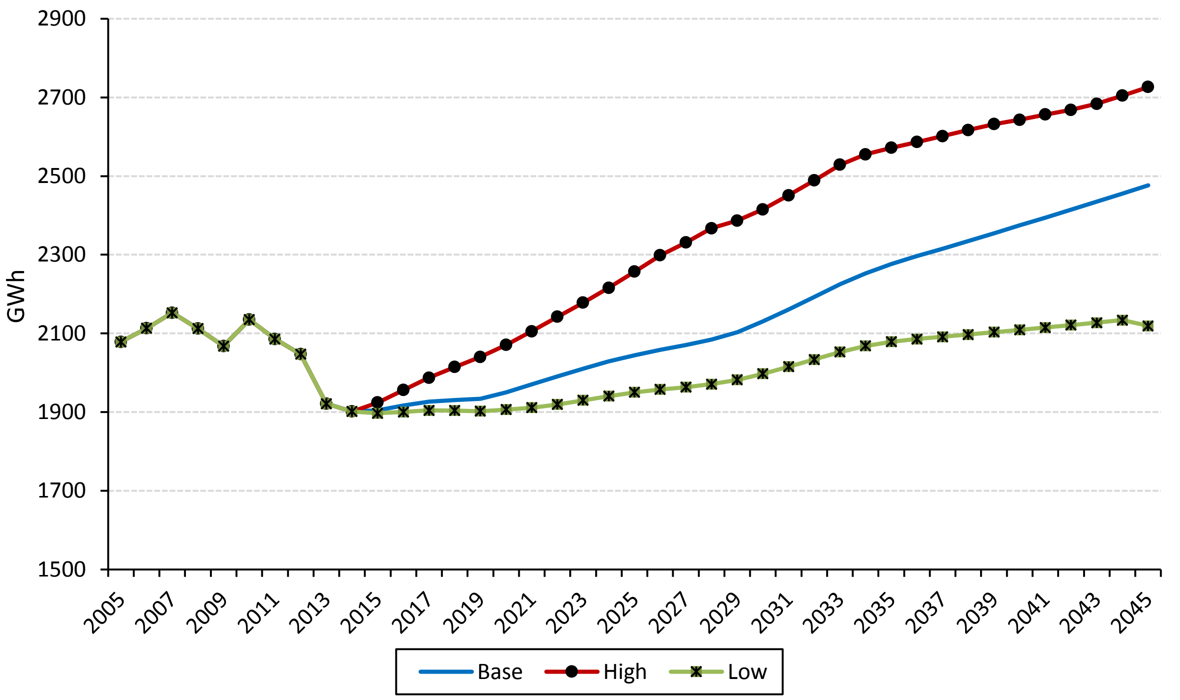


Figure 4.3: Tasmanian electricity sales by class – commercial
Base, high and low scenarios

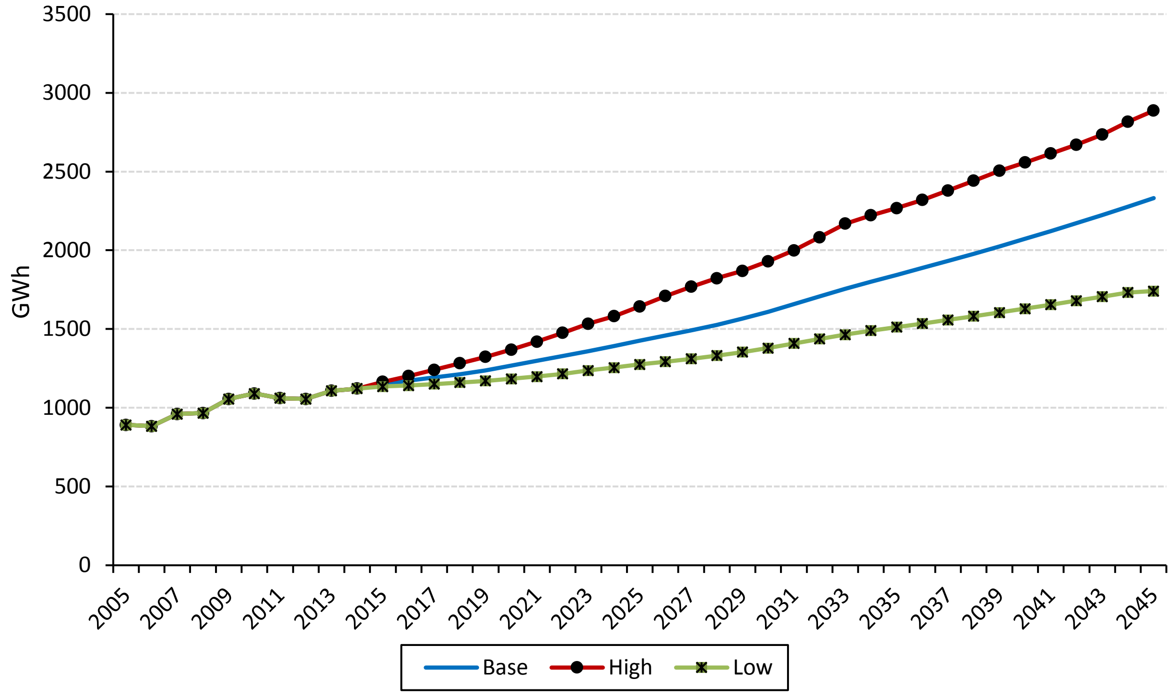
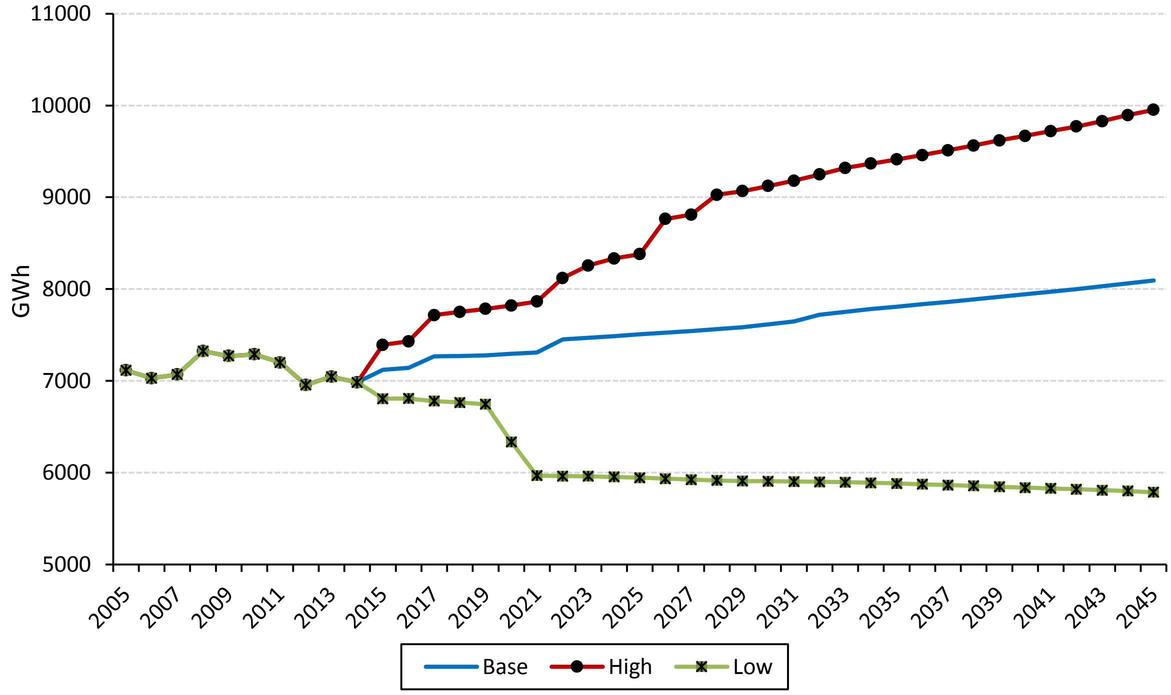


Figure 4.4: Tasmanian electricity sales by class – industrial
Base, high and low scenarios



4.2 Electricity generated

Table 4.1 shows electricity generated projections for the Tasmanian system for the base, low and high scenarios. Figure 4.5 shows the projection for Tasmanian electricity generated by scenario to 2025.

Under the base scenario, total Tasmanian electricity generated averages 0.9 per cent growth between 2014 and 2025. Under the high scenario, total electricity generated averages 1.9 per cent growth between 2014 and 2025. Under the low scenario, total Tasmanian electricity generated falls by an average rate of 0.8 per cent between 2014 and 2025.

Figure 4.5: Tasmanian total electricity generated by scenario – base, high and low scenarios – 2005 to 2045

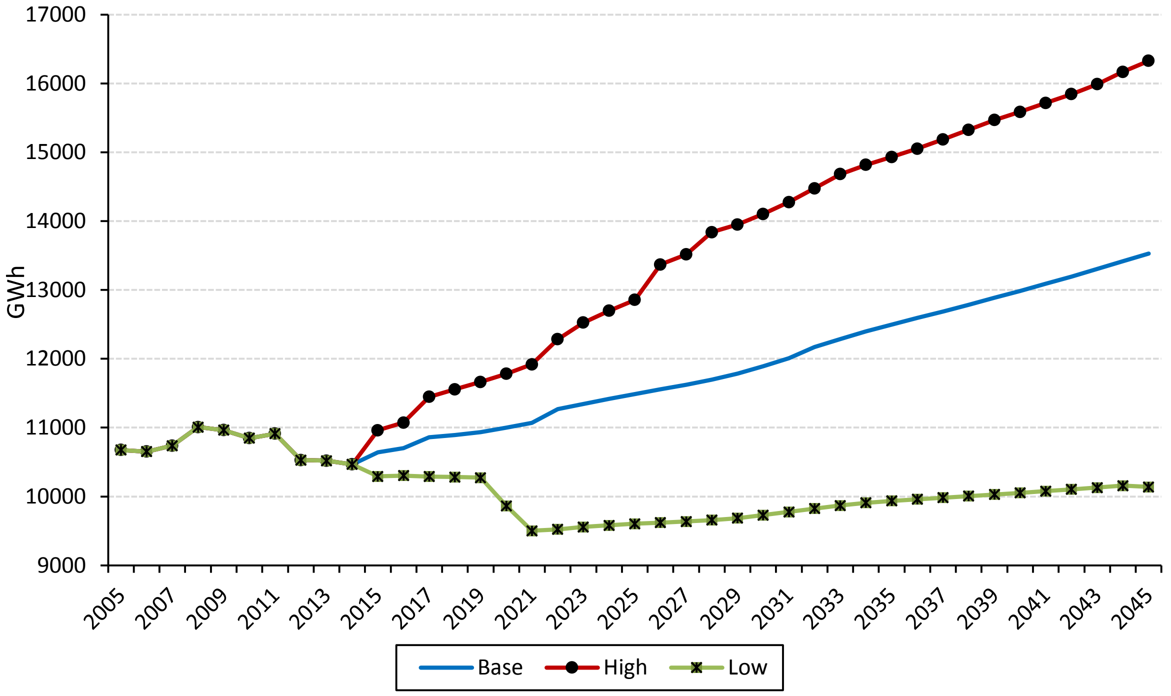


TABLE 4.1 TOTAL ELECTRICITY SALES BY CLASS - TASMANIA

	RESI-DENTIAL	COMMERC-IAL	INDUSTRIAL	PUBLIC LIGHTING	STATE TOTAL	TOTAL GENERATED	TOTAL GENERATED EXCLUDING EMBEDDED & WIND
Unit	*************************		GWH	******************************			
BASE							
2011	2085.65	1060.50	7199.90	36.91	10382.96	10912.88	9955.05
2012	2047.17	1055.80	6955.13	37.31	10095.41	10529.36	9595.80
2013	1921.28	1107.80	7043.94	36.10	10109.12	10518.76	9596.82
2014	1901.20	1122.12	6983.05	36.00	10042.37	10466.17	9102.48
2015	1904.74	1149.65	7119.10	37.07	10210.56	10641.46	9248.03
2016	1916.70	1171.09	7142.69	38.14	10268.63	10701.98	9308.55
2017	1926.04	1191.52	7265.06	39.26	10421.88	10861.70	9468.27
2018	1930.48	1212.61	7269.98	40.39	10453.47	10894.63	9501.20
2019	1933.45	1238.13	7278.64	41.52	10491.75	10934.52	9541.08
2020	1950.45	1266.81	7293.42	42.60	10553.28	10998.65	9605.22
2025	2044.69	1425.54	7505.72	48.47	11024.41	11489.66	10096.23
2030	2130.27	1609.86	7615.02	55.32	11410.46	11892.00	10498.57
2035	2276.05	1844.02	7808.18	63.22	11991.47	12497.53	11104.10
2040	2374.25	2072.82	7941.68	72.25	12461.00	12986.87	11593.44
2045	2476.01	2330.59	8091.87	82.57	12981.04	13528.86	12135.43
Percentage changes							
2014	-1.05	1.29	-0.86	-0.28	-0.66	-0.50	-5.15
2015	0.19	2.45	1.95	2.96	1.67	1.67	1.60
2016	0.63	1.86	0.33	2.89	0.57	0.57	0.65
2017	0.49	1.74	1.71	2.95	1.49	1.49	1.72
2018	0.23	1.77	0.07	2.89	0.30	0.30	0.35
2019	0.15	2.10	0.12	2.79	0.37	0.37	0.42
2020	0.88	2.32	0.20	2.60	0.59	0.59	0.67
Compound growth rate (per cent) -							
2014-2025	0.66	2.20	0.66	2.74	0.85	0.85	0.95
2020-2040	0.99	2.49	0.43	2.68	0.83	0.83	0.95
2014-2045	0.86	2.39	0.48	2.71	0.83	0.83	0.93
HIGH - Levels							
2015	1924.32	1164.19	7391.06	37.46	10517.02	10960.86	10960.86
2016	1955.96	1200.80	7430.21	38.94	10625.91	11074.34	9680.91
2017	1987.44	1240.41	7715.37	40.47	10983.68	11447.21	10053.78
2018	2014.40	1282.29	7750.40	42.01	11089.09	11557.07	10163.64
2019	2040.16	1323.55	7783.02	43.63	11190.36	11662.61	10269.18
2020	2070.45	1368.36	7820.61	45.33	11304.75	11781.83	10388.40
2025	2256.93	1643.90	8380.20	54.75	12335.78	12856.37	11462.93
2030	2415.11	1930.17	9123.09	64.87	13533.23	14104.36	12710.93
2035	2571.61	2267.93	9411.51	75.95	14327.00	14931.63	13538.20
2040	2643.14	2558.02	9668.67	87.69	14957.51	15588.75	14195.31
2045	2726.38	2887.14	9952.15	102.85	15668.52	16329.76	14936.33
Compound growth rate (per cent) -							
2014-2025	1.57	3.53	1.67	3.89	1.89	1.89	2.12
2020-2040	1.23	3.18	1.07	3.35	1.41	1.41	1.57
2014-2045	1.17	3.10	1.15	3.44	1.45	1.45	1.61
LOW - Levels							
2015	1896.86	1134.82	6806.11	36.69	9874.48	10291.20	8897.77
2016	1900.28	1141.50	6807.69	37.39	9886.87	10304.11	8910.68
2017	1904.29	1150.74	6780.20	38.12	9873.35	10290.02	8896.59
2018	1903.95	1160.72	6763.85	38.85	9867.37	10283.79	8890.36
2019	1902.14	1170.19	6745.07	39.56	9856.96	10272.94	8879.51
2020	1906.05	1184.07	6335.33	40.33	9465.78	9865.25	8471.82
2025	1950.26	1274.89	5944.06	45.51	9214.72	9603.60	8210.17
2030	1997.30	1379.21	5906.08	52.92	9335.51	9729.48	8336.05
2035	2078.55	1512.35	5881.36	61.53	9533.80	9936.14	8542.71
2040	2108.97	1629.62	5836.30	71.55	9646.44	10053.53	8660.10
2045	2119.01	1741.47	5785.89	81.93	9728.29	10138.84	8745.41
Compound growth rate (per cent) -							
2014-2025	0.23	1.17	-1.45	2.15	-0.78	-0.78	-0.93
2020-2040	0.51	1.61	-0.41	2.91	0.09	0.09	0.11
2014-2045	0.35	1.43	-0.60	2.69	-0.10	-0.10	-0.13

All data are for the financial year ending in June of the year specified.

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Figure 4.6: Total PV customers, Tasmania

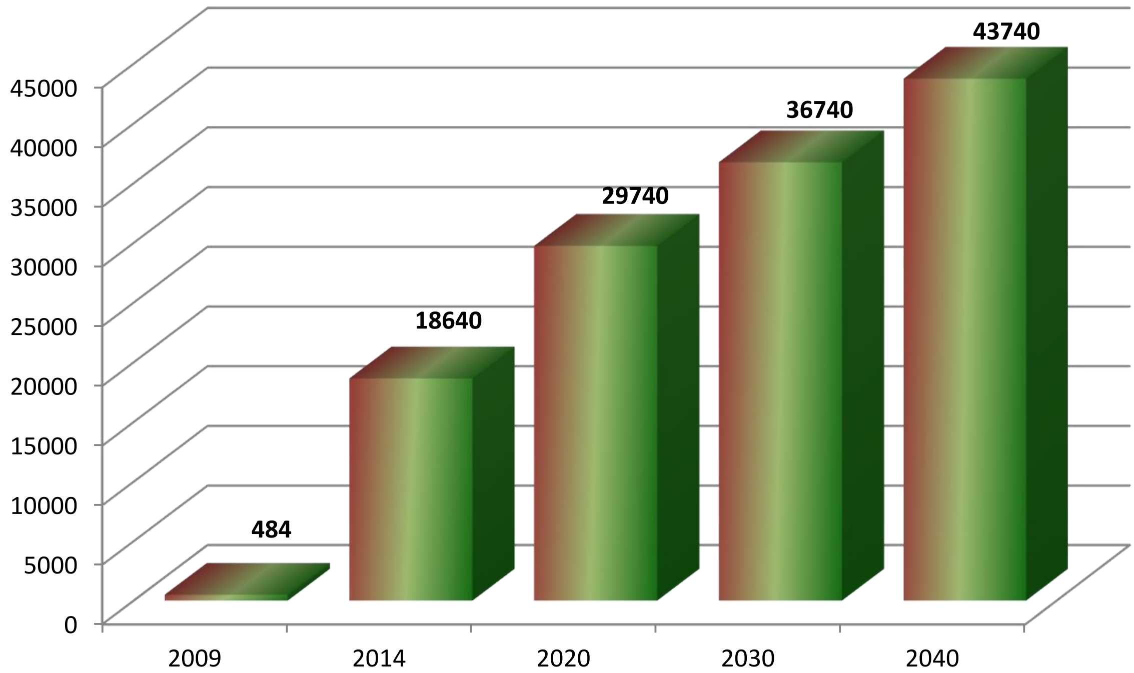

Figure 4.7: Total PV capacity, Tasmania

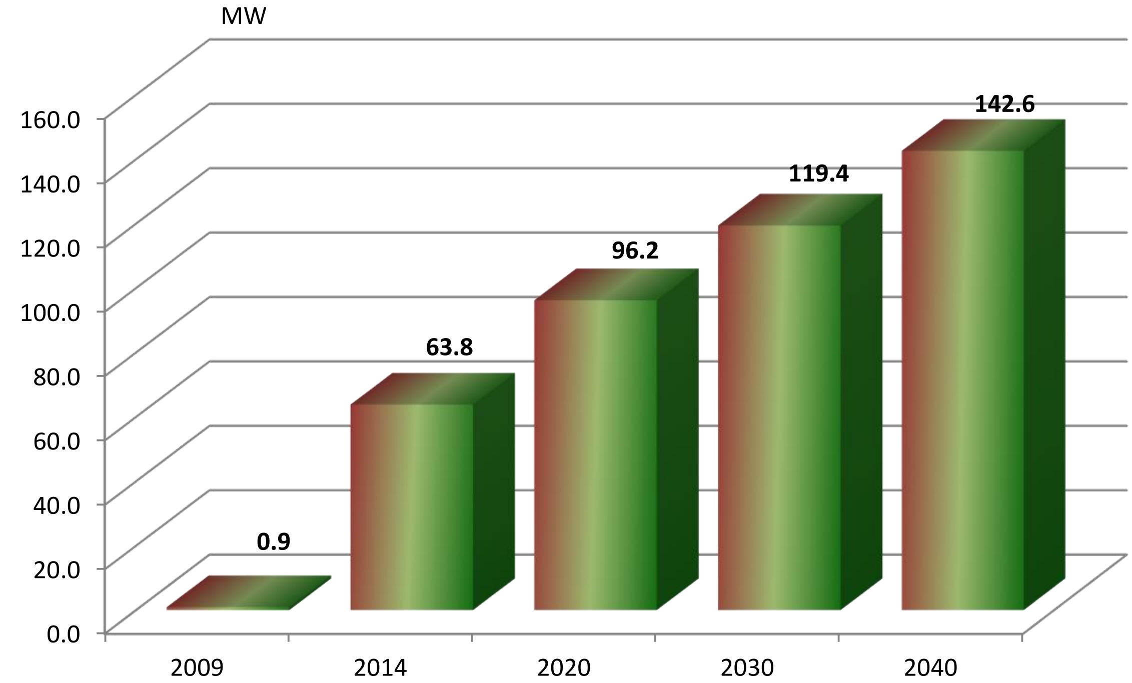

TABLE 4.5 Small Scale PV - Tasmania

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
Unit	Number	** MW **	** KW **	***********	GWH	**********	** MW **
BASE							
2011	4560.00	7.16	1.57	7.50	2.62	4.87	2.15
2012	7829.00	15.64	2.00	13.26	4.64	8.62	4.69
2013	12481.00	35.23	2.22	25.68	8.99	16.69	10.57
2014	18640.00	63.81	2.44	43.46	15.21	28.25	19.14
2015	21640.00	71.78	2.66	61.57	21.55	40.02	21.53
2016	24640.00	80.41	2.88	76.85	26.90	49.95	24.12
2017	27640.00	89.41	3.00	92.15	32.25	59.89	26.82
2018	28340.00	91.59	3.12	102.70	35.94	66.75	27.48
2019	29040.00	93.84	3.22	109.05	38.17	70.88	28.15
2020	29740.00	96.16	3.32	115.24	40.33	74.91	28.85
2025	33240.00	107.77	3.32	130.94	45.83	85.11	32.33
2030	36740.00	119.39	3.32	144.87	50.71	94.17	35.82
2035	40240.00	131.00	3.32	158.81	55.58	103.22	39.30
2040	43740.00	142.61	3.32	172.74	60.46	112.28	42.78
2045	47240.00	154.22	3.32	186.67	65.34	121.34	46.27
Percentage changes							
2014	49.35	81.12	9.92	69.22	69.22	69.22	81.12
2015	16.09	12.50	9.03	41.66	41.66	41.66	12.50
2016	13.86	12.03	8.28	24.82	24.82	24.82	12.03
2017	12.18	11.18	4.17	19.90	19.90	19.90	11.18
2018	2.53	2.44	4.00	11.45	11.45	11.45	2.44
2019	2.47	2.46	3.21	6.19	6.19	6.19	2.46
2020	2.41	2.47	3.11	5.67	5.67	5.67	2.47
Compound growth rate (per cent) -							
2014-2025	5.40	4.88	2.84	10.55	10.55	10.55	4.88
2020-2040	1.95	1.99	0.00	2.04	2.04	2.04	1.99
2014-2045	3.05	2.89	1.00	4.81	4.81	4.81	2.89
HIGH - Levels							
2015	22140.00	73.11	2.66	62.33	21.82	40.52	21.93
2016	25640.00	83.18	2.88	79.34	27.77	51.57	24.95
2017	29140.00	93.67	3.00	96.55	33.79	62.76	28.10
2018	32640.00	104.58	3.12	113.34	39.67	73.67	31.37
2019	36140.00	115.84	3.22	130.72	45.75	84.97	34.75
2020	39640.00	127.46	3.32	148.57	52.00	96.57	38.24
2025	57140.00	185.51	3.32	220.51	77.18	143.33	55.65
2030	74640.00	243.57	3.32	290.18	101.56	188.62	73.07
2035	92140.00	301.63	3.32	359.85	125.95	233.90	90.49
2040	109640.00	359.69	3.32	429.52	150.33	279.19	107.91
2045	127140.00	417.74	3.32	499.19	174.72	324.47	125.32
Compound growth rate (per cent) -							
2014-2025	10.72	10.19	2.84	15.91	15.91	15.91	10.19
2020-2040	5.22	5.32	0.00	5.45	5.45	5.45	5.32
2014-2045	6.39	6.25	1.00	8.19	8.19	8.19	6.25
LOW - Levels							
2015	21140.00	70.45	2.66	60.81	21.28	39.52	21.14
2016	23440.00	77.07	2.88	74.03	25.91	48.12	23.12
2017	25740.00	83.96	3.00	86.68	30.34	56.34	25.19
2018	28040.00	91.13	3.12	98.66	34.53	64.13	27.34
2019	30340.00	98.53	3.22	110.95	38.83	72.12	29.56
2020	32640.00	106.17	3.32	123.48	43.22	80.26	31.85
2025	44140.00	144.32	3.32	171.15	59.90	111.25	43.30
2030	55640.00	182.47	3.32	216.93	75.93	141.00	54.74
2035	67140.00	220.62	3.32	262.71	91.95	170.76	66.19
2040	78640.00	258.77	3.32	308.49	107.97	200.52	77.63
2045	90140.00	296.93	3.32	354.28	124.00	230.28	89.08
Compound growth rate (per cent) -							
2014-2025	8.15	7.70	2.84	13.27	13.27	13.27	7.70
2020-2040	4.49	4.56	0.00	4.68	4.68	4.68	4.56
2014-2045	5.22	5.09	1.00	7.00	7.00	7.00	5.09

All data are for the financial year ending in June of the year specified.

4.3 Natural gas sales to 2045

Table 4.6 shows forecast natural gas sales by class to 2045 for the base, high and low growth scenarios.

A gas transmission pipeline from the Victorian Longford processing plant direct to the Tasmanian mainland (Duke Energy proposal) was completed in mid-2002. Major gas transmission customers are Pacific Aluminium (Bell Bay), Ecka Granules, Australian Bulk Minerals and gas fired power generators.

The Tasmanian Government in 2003 awarded the distribution roll-out to Powerco, contributing $40 million to subsidise the distribution and reticulation of gas over the 2003 to 2007 period. Details of Stage One and Two of the roll-out were outlined in Section 3.7.

In this scenario for gas supply, the following assumptions have been made:

- industry usage, post the introduction of new supply, is relatively slow, since the replacement costs/conversion of plant and equipment is relatively high industry usage gradually ramps up over a 10 year period;
- the electricity industry commits itself to using natural gas as a significant fuel in generation to meet additional load requirements;
- the take-up of gas by residential customers is limited by the slow roll-out of reticulation systems, and the slow take-up of new connections;
- several major new industrial developments are over the 2015 to 2020 period (e.g. paper production, dairy and other food processing);
- a number of small cogeneration plants are developed by industry and the public sector (hospitals). A cogeneration plant was completed by Simplot, a food manufacturer, in December 2012.

The main cogeneration plant that was proposed is one associated with the proposed Gunns pulp mill. This is not included in the projection as this project has been cancelled.

As indicated in Table 4.6, natural gas usage by the residential sector rises to around 0.8 PJs by 2015 and 1.7 PJs by 2025.

TABLE 4.6 TASMANIA: GAS CONSUMPTION

	RESI-DENTIAL	INDUS-TRIAL	COMMER-CIAL (EXCL. NGV)	TRANSPORT (NGV)	ELECTRICITY GENERA-TION	GAS PRODUC-TION AND DISTRI-BUTION	WATER, SEWERAGE AND DRAINAGE	STATE TOTAL
Unit	******************************			PETAJOULES	******************************			
BASE								
2011	0.42	5.12	0.49	0.00	12.44	0.00	0.01	18.49
2012	0.52	5.68	0.61	0.00	12.44	0.00	0.02	19.26
2013	0.61	6.27	0.72	0.00	12.45	0.00	0.02	20.07
2014	0.70	6.32	0.75	0.00	12.51	0.00	0.02	20.29
2015	0.79	6.32	0.79	0.00	12.54	0.00	0.02	20.45
2016	0.87	6.53	0.82	0.00	12.58	0.00	0.02	20.82
2017	0.96	7.49	0.86	0.00	12.81	0.00	0.02	22.14
2018	1.05	8.33	0.88	0.00	13.04	0.00	0.02	23.31
2019	1.14	8.24	0.90	0.00	13.07	0.00	0.02	23.37
2020	1.24	8.18	0.92	0.00	13.12	0.00	0.02	23.48
2025	1.74	8.04	1.05	0.00	13.39	0.00	0.02	24.25
2030	2.26	8.05	1.20	0.00	13.68	0.00	0.02	25.21
2035	2.82	8.08	1.38	0.00	14.08	0.00	0.02	26.39
2040	3.40	8.08	1.61	0.00	14.40	0.00	0.02	27.51
2045	4.00	8.11	1.89	0.00	14.75	0.00	0.02	28.76
Percentage changes								
2014	14.44	0.77	3.96	0.00	0.44	0.00	2.83	1.10
2015	12.73	-0.07	5.07	0.00	0.31	0.00	3.16	0.79
2016	11.11	3.35	4.83	0.00	0.27	0.00	3.24	1.81
2017	10.23	14.70	4.67	0.00	1.82	0.00	3.25	6.32
2018	9.18	11.23	2.10	0.00	1.79	0.00	0.47	5.31
2019	8.25	-1.06	2.23	0.00	0.29	0.00	0.45	0.24
2020	8.77	-0.71	2.51	0.00	0.36	0.00	0.41	0.48
Compound growth rate (per cent) -								
2014-2025	8.68	2.22	3.18	0.00	0.62	0.00	1.24	1.63
2020-2040	5.18	-0.06	2.82	0.00	0.47	0.00	0.41	0.79
2014-2045	5.80	0.81	3.03	0.00	0.53	0.00	0.70	1.13
HIGH - Levels								
2015	3.26	8.88	1.24	0.00	13.04	0.00	0.03	26.45
2016	3.69	8.95	1.26	0.00	13.10	0.00	0.03	27.03
2017	4.12	10.07	1.52	0.00	13.36	0.00	0.03	29.10
2018	4.55	10.03	1.55	0.00	13.61	0.00	0.03	29.77
2019	4.98	9.91	1.59	0.00	13.67	0.00	0.03	30.19
2020	5.41	9.85	1.63	0.00	13.74	0.00	0.03	30.67
2025	7.63	9.78	1.87	0.00	14.16	0.00	0.04	33.48
2030	9.82	9.90	2.12	0.00	14.56	0.00	0.04	36.43
2035	12.11	10.03	2.42	0.00	15.02	0.00	0.04	39.62
2040	14.39	10.15	2.80	0.00	15.36	0.00	0.04	42.73
2045	16.84	10.32	3.28	0.00	15.73	0.00	0.04	46.20
Compound growth rate (per cent) -								
2014-2025	9.42	1.20	4.95	0.00	0.80	0.00	3.08	2.50
2020-2040	5.01	0.15	2.73	0.00	0.56	0.00	0.53	1.67
2014-2045	5.92	0.60	3.59	0.00	0.62	0.00	1.44	1.93
LOW - Levels								
2015	3.17	4.12	0.60	0.00	12.46	0.00	0.01	20.35
2016	3.54	4.35	0.66	0.00	12.47	0.00	0.01	21.04
2017	3.91	4.58	0.72	0.00	12.69	0.00	0.02	21.93
2018	4.29	4.55	0.74	0.00	12.92	0.00	0.02	22.52
2019	4.66	4.49	0.76	0.00	12.94	0.00	0.02	22.87
2020	5.04	4.47	0.78	0.00	12.97	0.00	0.02	23.28
2025	7.09	4.41	0.90	0.00	13.16	0.00	0.02	25.57
2030	9.30	4.43	1.03	0.00	13.36	0.00	0.02	28.14
2035	11.55	4.48	1.19	0.00	13.62	0.00	0.02	30.87
2040	13.83	4.46	1.39	0.00	13.81	0.00	0.02	33.51
2045	16.07	4.46	1.60	0.00	13.98	0.00	0.02	36.13
Compound growth rate (per cent) -								
2014-2025	8.84	0.74	4.37	0.00	0.51	0.00	2.05	2.32
2020-2040	5.17	-0.01	2.90	0.00	0.32	0.00	0.25	1.84
2014-2045	5.81	0.30	3.43	0.00	0.38	0.00	0.83	1.95

All data are for the financial year ending in June of the year specified.

5. Tasmanian maximum demand forecasts to 2045

5.1 Introduction

This section presents maximum demand estimates for Tasmania to 2045. The methodology for forecasting Tasmanian maximum demands for summer and winter is outlined in Section 3. The commentary focuses on the forecasts to 2022, with annual forecasts to 2045, are included in Appendix D.

Projections in this section are reported on three alternative bases:

(i) summer and winter MDs including embedded generations;

(ii) summer and winter MDs excluding embedded generators; and

(iii) summer and winter MDs excluding embedded generators and wind farms.

The following hydro generating units are classified as non-scheduled:

- Butlers Gorge;
- Rowallan;
- Paloona;
- Repluse; and
- Cluny.

The contribution of non-scheduled generation needs to be deducted from the maximum demand forecast to obtain scheduled maximum demands. The contribution of non-scheduled wind generation is assumed to be zero for both summer and winter MDs. For non-scheduled hydro-electric generators, NIEIR's approach was to estimate the average contribution of these generators to the respective summer and winter peaks over the last three years using the top five peaks only. This work was done for the 2014 TasNetworks update. NIEIR, after doing this, adopted to deduct 65.8 MW from the winter peak and 37.5 MW from the summer peak. For wind, the availability of wind (as a percentage of installed capacity) was assumed to be 0 per cent, as advised by TasNetworks. Given the commissioning of a new wind farm in Tasmania, this assumption will be revised.

The POE demands presented in this section are benchmarked against POE temperatures. Section 3.2 outlines the POE temperatures for Tasmania. Major load in Tasmania is a significant component of the forecast maximum demand. There are currently four major industrial loads in Tasmania. Smaller major loads are also modelled separately. Both coincident and non-coincident peaks for both major industrial loads and smaller major loads are included in this section.

Forecasts of winter and summer peaks in this section and the commentary, focuses on the MDs including non-scheduled generators. Forecasts of winter and summer peaks excluding these non-scheduled generators are provided.

5.2 A review of the 2014 winter MD forecast[1]

The actual MD (native) occurred on 11 August 2014 and was 1,690 MW. The temperature was around a 93rd POE temperature, so close to a 90th percentile MD. NIEIR's 90th percentile forecast from 2013 was 1,677 MW.

Major industrial load at MD was around 665 MW, around 23 MW above the 2013 forecast. The total forecast error is around 10 MW, however, excluding MI load the forecast error is 25 MW.

5.3 Forecasts of system maximum demand – summary of approach

Forecasts of maximum summer and winter demands (MDs) to 2045 are presented for three alternative temperature sets. These include temperatures of:

- winter temperatures of 0.9°C, 2.1°C and 3.2°C representing the approximate 10th, 50th and 90th percentiles; and
- summer temperatures of 7.0°C, 8.7°C and 9.9°C representing the 10th, 50th and 90th percentiles for the summer season.

Forecasts of winter and summer maximum demands are formulated from historical regression equations estimated from historical data supplied by TasNetworks, weather data supplied by the Bureau of Meteorology, and economic data collated by the Australian Bureau of Statistics. These regression equations are estimated excluding major load in Tasmania.

The key drivers of the forecasts of maximum demand for Tasmania are:

- gross state product growth;
- temperature sensitive load growth; and
- the indirect impact of electricity prices and other policies on demand.

NIEIR regularly re-estimates these maximum demand forecast equations and performs diagnostic checks on the models fitted to the Tasmanian peak demand data. Section 3.7 and Appendix C present additional details, including various error statistics.

It is important to note that all data in these tables for summer MDs refer to the financial year ending 30 June. For winter MDs the forecasts are presented on a calendar year basis.

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1 Demands represent the average half hourly demand (over 30 minutes).

5.4 Forecasts of summer and winter maximum demands – 10th percentile

Forecasts of winter and summer maximum demands for the base, high and low scenarios are presented in Tables 5.1 to 5.18. This commentary focuses on the 10th percentile. Commentary on the 50th percentile follows below.

The winter forecasts are presented in Tables 5.1 to 5.9. The winter demands are presented:

- including non-scheduled generation;
- excluding non-scheduled hydro generation; and
- excluding non-scheduled hydro and wind generation.

The winter demands are also separated into major industrial and small major loads. The maximum coincident demands for large industrials and small majors are presented in Tables 5.5, 5.6 and 5.7 by customer. Tables 5.8 and 5.9 show the maximum non-coincident forecasts for winter by large industrial and small major customers.

The summer forecasts are presented in Tables 5.10 to 5.18. The forecast tables for summer provide the same type of information that is provided for winter MDs.

It is important to note that the differences between the base, high and low growth scenarios reflects both different underlying economic growth as well as different major load assumptions for the top four Tasmanian industrial customers between each scenario.

For these weather conditions:

- the winter peak increases to 1,723 MW in winter 2015, compared to the actual MD recorded in winter 2014 of 1,690 MW; and
- the summer peak rises to 1,212 MW in 2014-15 compared to the actual in summer 2013-14 of 1,267 MW.

Figures 5.1 and 5.2 show the projections for winter and summer maximum demands respectively for each scenario through to 2025 for the 10th percentile.

The base scenario

- Under the base scenario the winter MD rises to 1,708 MW by winter 2015 and 1,901 MW by winter 2025.
- The summer MD under the base scenario rises to 1,212 MW by 2014-15 and to 1,401 MW by 2024-25.
- The winter MD in Tasmania under the base scenario rises by an average annual rate of 1.1 per cent respectively between 2015 and 2025, compared to average annual growth in total energy generated over the same period of 0.9 per cent.

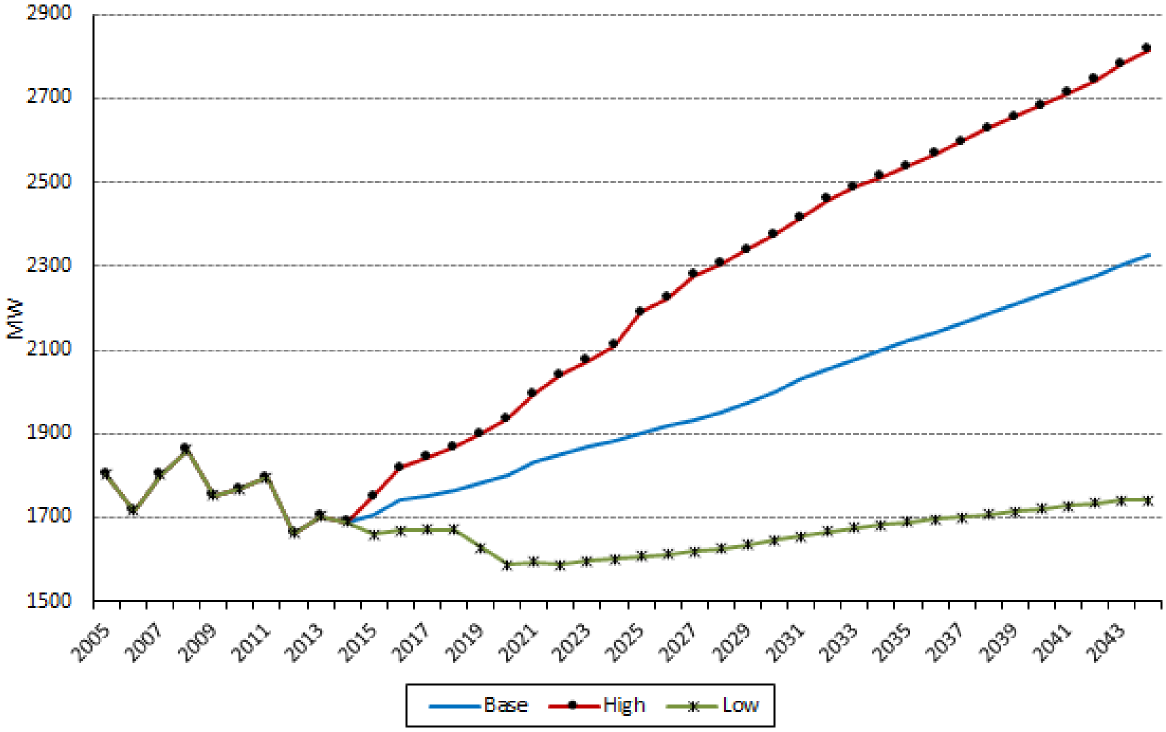
The high scenario

- Under the high scenario, the winter MD rises to 1,750 MW by winter 2015 and 2,190 MW by winter 2025. The winter MD rises by an average annual rate of 2.3 per cent between 2015 and 2025, compared to average annual growth in total energy generated of 1.9 per cent over the same period.
- The summer MD under the high scenario falls to 1,660 MW by summer 2014-15 and 1,608 MW by 2024-25. The summer MD under the high scenario increases at an average annual rate of 2.2 per cent, compared to average annual growth in energy generated of 1.9 per cent.

The low scenario

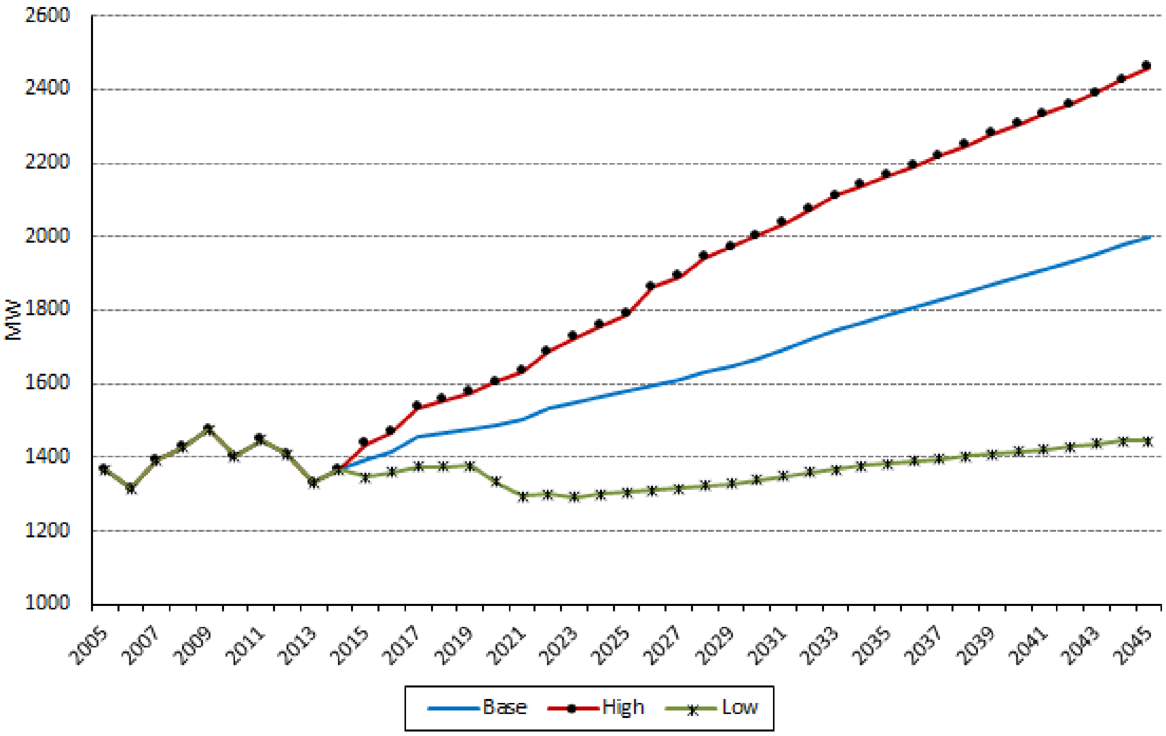
- Under the low scenario, the winter MD rises to 1,675 MW by winter 2015 and falls to 1,623 MW by winter 2025. This fall partly reflects the closure of a major industrial load under the low scenario (TEMCO). The winter MD falls by an average annual rate of -0.3 per cent between 2014 and 2025, compared to an average reduction in total energy generated of -0.8 per cent.
- The summer MD under the low scenario falls to 1,164 MW by summer 2014-15 and falls to 1,123 MW by 2024-25. The summer MD rises by an average annual rate of 1.1 per cent between 2014 and 2025 under the low scenario, compared to average annual reduction in total energy generated over the same period of -0.8 per cent.

Figure 5.1: Tasmanian winter generated maximum demand (including embedded generation)
10th percentile (0.9 degrees Celsius)



Note: Calendar years.

Figure 5.2: Tasmanian summer generated maximum demand
10th percentile (7.0 degrees Celsius)



5.5 Forecasts of summer and winter maximum demands – 50th percentile

Forecasts of Tasmanian winter and summer maximum demands for the base, high and low scenarios for the 50th percentile are also presented in Table 5.1. These temperatures represent more modest conditions at system maximum demand. Figures 5.3 and 5.4 show the projections for winter and summer maximum demands under these more extreme temperature conditions for each scenario to 2025.

The key features of forecasts for the next year are:

- the winter MD falls from 1,690 MW in 2014 to 1,687 MW in winter 2015; and
- the summer MD rises from 1,267 MW in 2013-14 to 1,212 MW in summer 2014-15.

Figure 5.3: Tasmanian winter generated maximum demand 50th percentile (2.1 degrees Celsius)

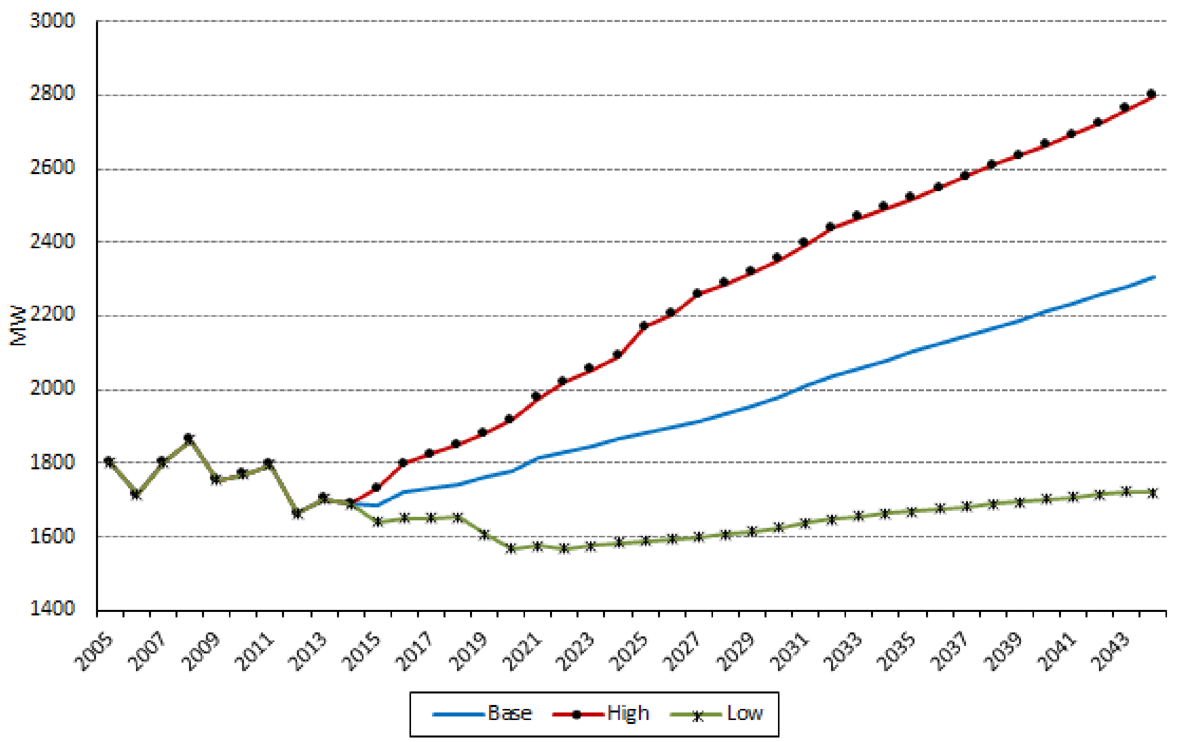


Figure 5.4: Tasmanian summer generated maximum demand 50th percentile (8.7 degrees Celsius)

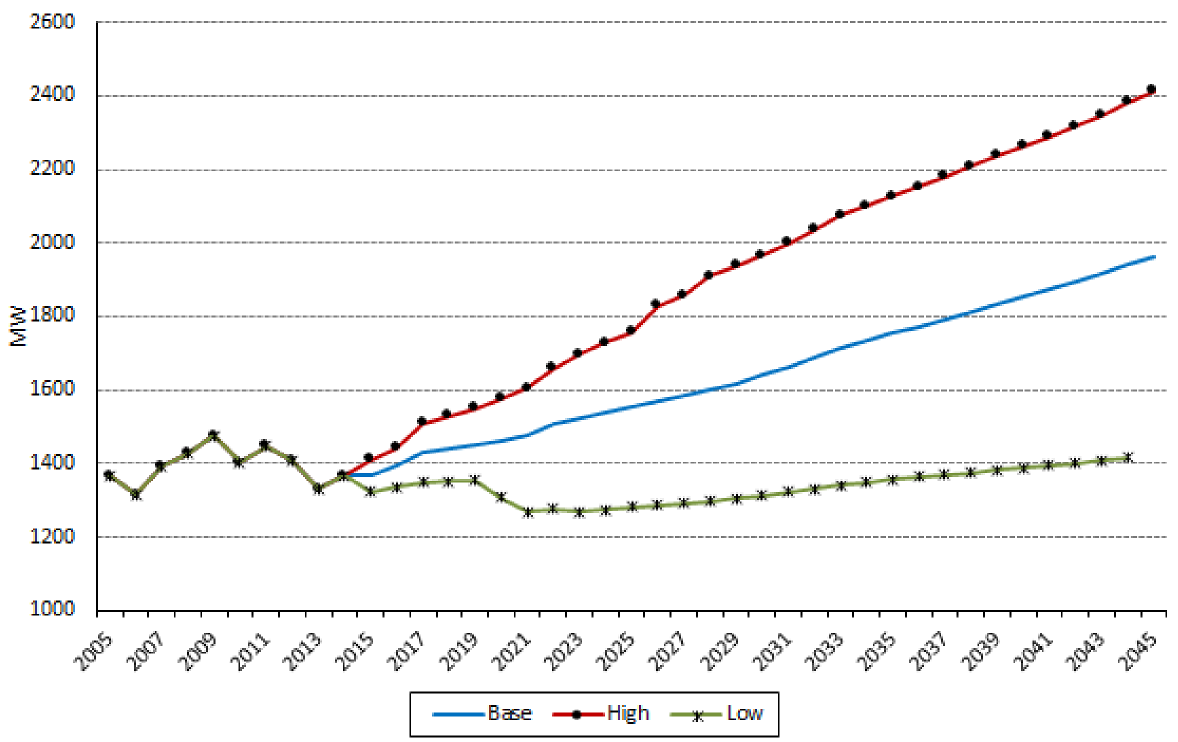


TABLE 5.1 MAXIMUM WINTER DEMANDS – TASMANIA (INCLUDING NON-SCHEDULED GENERATION)

	WINTER MAXIMUM DEMAND		
	PERCENTILES		
	10TH	50TH	90TH
	AVERAGE TEMPERATURE(CELSIUS)		
	1.5	2.6	3.6
Unit	************	MW	**********
BASE			
2012	1662.40	1662.40	1662.40
2013	1703.10	1703.10	1703.10
2014	1689.50	1689.50	1689.50
2015	1707.64	1687.44	1671.04
2016	1742.89	1722.70	1706.32
2017	1753.07	1732.88	1716.51
2018	1764.64	1744.46	1728.10
2019	1781.28	1761.11	1744.77
2020	1799.69	1779.53	1763.22
2025	1900.97	1880.87	1864.66
2030	2000.50	1980.46	1964.40
2035	2121.33	2101.38	2085.48
2040	2230.39	2210.52	2194.77
2044	2326.95	2307.15	2291.53
Percentage changes			
2013	2.45	2.45	2.45
2014	-0.80	-0.80	-0.80
2015	1.07	-0.12	-1.09
2016	2.06	2.09	2.11
2017	0.58	0.59	0.60
2018	0.66	0.67	0.68
2019	0.94	0.95	0.96
Compound growth rate (per cent) -			
2015-2025	1.08	1.09	1.10
2015-2044	1.07	1.08	1.09
HIGH - Levels			
2015	1750.19	1730.01	1713.65
2016	1817.73	1797.56	1781.24
2017	1843.92	1823.78	1807.49
2018	1869.30	1849.17	1832.91
2019	1900.79	1880.68	1864.46
2020	1936.37	1916.28	1900.10
2025	2189.50	2169.53	2153.60
2030	2373.76	2353.91	2338.20
2035	2538.20	2518.47	2503.00
2040	2683.18	2663.55	2648.29
2044	2816.65	2797.11	2782.04
Compound growth rate (per cent) -			
2015-2025	2.26	2.29	2.31
2015-2044	1.65	1.67	1.68
LOW - Levels			
2015	1659.56	1639.34	1622.91
2016	1669.33	1649.12	1632.69
2017	1671.24	1651.03	1634.60
2018	1672.22	1652.00	1635.57
2019	1627.73	1607.51	1591.08
2020	1588.83	1568.61	1552.17
2025	1608.07	1587.87	1571.47
2030	1645.81	1625.64	1609.28
2035	1689.28	1669.14	1652.84
2040	1721.35	1701.22	1684.96
2044	1740.97	1720.85	1704.61
Compound growth rate (per cent) -			
2015-2025	-0.31	-0.32	-0.32
2015-2044	0.17	0.17	0.17

All data are for the Calendar year ending in December of the year specified.

TABLE 5.2 MAXIMUM WINTER DEMANDS - TASMANIA(EXCLUDING NON-SCHEDULED HYDRO GENERATION)

	WINTER MAXIMUM DEMAND		
	PERCENTILES		
	10TH	50TH	90TH
	AVERAGE TEMPERATURE(CELSIUS)		
	1.5	2.6	3.6
Unit	**********	MW	***********
BASE			
2012	1574.50	1574.50	1574.50
2013	1659.20	1659.20	1659.20
2014	1601.30	1601.30	1601.30
2015	1641.84	1621.64	1605.24
2016	1677.09	1656.90	1640.52
2017	1687.27	1667.08	1650.71
2018	1698.84	1678.66	1662.30
2019	1715.48	1695.31	1678.97
2020	1733.89	1713.73	1697.42
2025	1835.17	1815.07	1798.86
2030	1934.70	1914.66	1898.60
2035	2055.53	2035.58	2019.68
2040	2164.59	2144.72	2128.97
2044	2261.15	2241.35	2225.73
Percentage changes			
2013	5.38	5.38	5.38
2014	-3.49	-3.49	-3.49
2015	2.53	1.27	0.25
2016	2.15	2.17	2.20
2017	0.61	0.61	0.62
2018	0.69	0.69	0.70
2019	0.98	0.99	1.00
Compound growth rate (per cent) -			
2015-2025	1.12	1.13	1.15
2015-2044	1.11	1.12	1.13
HIGH - Levels			
2015	1684.39	1664.21	1647.85
2016	1751.93	1731.76	1715.44
2017	1778.12	1757.98	1741.69
2018	1803.50	1783.37	1767.11
2019	1834.99	1814.88	1798.66
2020	1870.57	1850.48	1834.30
2025	2123.70	2103.73	2087.80
2030	2307.96	2288.11	2272.40
2035	2472.40	2452.67	2437.20
2040	2617.38	2597.75	2582.49
2044	2750.85	2731.32	2716.24
Compound growth rate (per cent) -			
2015-2025	2.34	2.37	2.39
2015-2044	1.71	1.72	1.74
LOW - Levels			
2015	1593.76	1573.54	1557.11
2016	1603.53	1583.32	1566.89
2017	1605.44	1585.23	1568.80
2018	1606.42	1586.20	1569.77
2019	1561.93	1541.71	1525.28
2020	1523.03	1502.81	1486.37
2025	1542.27	1522.07	1505.67
2030	1580.01	1559.84	1543.48
2035	1623.48	1603.34	1587.04
2040	1655.55	1635.42	1619.16
2044	1675.17	1655.05	1638.81
Compound growth rate (per cent) -			
2015-2025	-0.33	-0.33	-0.34
2015-2044	0.17	0.17	0.18

All data are for the Calendar year ending in December of the year specified.

TABLE 5.3 MAXIMUM WINTER DEMANDS – TASMANIA (EXCLUDING NON-SCHEDULED HYDRO AND WIND GENERATION)

		WINTER MAXIMUM DEMAND		
		PERCENTILES		
		10TH	50TH	90TH
		AVERAGE TEMPERATURE (CELSIUS)		
		1.5	2.6	3.6
Unit		**********	MW	***********
BASE				
	2012	1573.80	1573.80	1573.80
	2013	1582.20	1582.20	1582.20
	2014	1557.10	1557.10	1557.10
	2015	1596.84	1576.64	1560.24
	2016	1632.09	1611.90	1595.52
	2017	1642.27	1622.08	1605.71
	2018	1653.84	1633.66	1617.30
	2019	1670.48	1650.31	1633.97
	2020	1688.89	1668.73	1652.42
	2025	1790.17	1770.07	1753.86
	2030	1889.70	1869.66	1853.60
	2035	2010.53	1990.58	1974.68
	2040	2119.59	2099.72	2083.97
	2044	2216.15	2196.35	2180.73
Percentage changes				
	2013	0.53	0.53	0.53
	2014	-1.59	-1.59	-1.59
	2015	2.55	1.25	0.20
	2016	2.21	2.24	2.26
	2017	0.62	0.63	0.64
	2018	0.70	0.71	0.72
	2019	1.01	1.02	1.03
Compound growth rate (per cent) -				
	2015-2025	1.15	1.16	1.18
	2015-2044	1.14	1.15	1.16
HIGH - Levels				
	2015	1639.39	1619.21	1602.85
	2016	1706.93	1686.76	1670.44
	2017	1733.12	1712.98	1696.69
	2018	1758.50	1738.37	1722.11
	2019	1789.99	1769.88	1753.66
	2020	1825.57	1805.48	1789.30
	2025	2078.70	2058.73	2042.80
	2030	2262.96	2243.11	2227.40
	2035	2427.40	2407.67	2392.20
	2040	2572.38	2552.75	2537.49
	2044	2705.85	2686.32	2671.24
Compound growth rate (per cent) -				
	2015-2025	2.40	2.43	2.46
	2015-2044	1.74	1.76	1.78
LOW - Levels				
	2015	1548.76	1528.54	1512.11
	2016	1558.53	1538.32	1521.89
	2017	1560.44	1540.23	1523.80
	2018	1561.42	1541.20	1524.77
	2019	1516.93	1496.71	1480.28
	2020	1478.03	1457.81	1441.37
	2025	1497.27	1477.07	1460.67
	2030	1535.01	1514.84	1498.48
	2035	1578.48	1558.34	1542.04
	2040	1610.55	1590.42	1574.16
	2044	1630.17	1610.05	1593.81
Compound growth rate (per cent) -				
	2015-2025	-0.34	-0.34	-0.35
	2015-2044	0.18	0.18	0.18

All data are for the Calendar year ending in December of the year specified.

TABLE 5.4 MAXIMUM WINTER DEMANDS (10TH, 50TH, 90TH PERCENTILES) – TASMANIA (INCLUDING NON-SCHEDULED GENERATION)

	10TH PERCENTILE			50TH PERCENTILE			90TH PERCENTILE		
	EXCLUDING MAJOR LOAD	MAJOR LOAD & SMALL MAJORS	TOTAL	EXCLUDING MAJORS	MAJOR LOAD & SMALL MAJORS	TOTAL	EXCLUDING MAJORS	MAJOR LOAD & SMALL MAJORS	TOTAL
Unit	MW								
BASE									
2012	1034.84	627.56	1662.40	1034.84	627.56	1662.40	1034.84	627.56	1662.40
2013	975.65	727.45	1703.10	975.65	727.45	1703.10	975.65	727.45	1703.10
2014	956.49	733.01	1689.50	956.49	733.01	1689.50	956.49	733.01	1689.50
2015	999.68	707.96	1707.64	979.48	707.96	1687.44	963.08	707.96	1671.04
2016	1021.80	721.10	1742.89	1001.61	721.10	1722.70	985.22	721.10	1706.32
2017	1031.81	721.25	1753.07	1011.63	721.25	1732.88	995.26	721.25	1716.51
2018	1043.31	721.32	1764.64	1023.13	721.32	1744.46	1006.77	721.32	1728.10
2019	1059.86	721.41	1781.28	1039.69	721.41	1761.11	1023.35	721.41	1744.77
2020	1077.94	721.75	1799.69	1057.79	721.75	1779.53	1041.47	721.75	1763.22
2025	1163.48	737.50	1900.97	1143.37	737.50	1880.87	1127.17	737.50	1864.66
2030	1260.30	740.20	2000.50	1240.26	740.20	1980.46	1224.20	740.20	1964.40
2035	1374.74	746.59	2121.33	1354.79	746.59	2101.38	1338.89	746.59	2085.48
2040	1482.48	747.91	2230.39	1462.61	747.91	2210.52	1446.86	747.91	2194.77
2044	1577.83	749.12	2326.95	1558.02	749.12	2307.15	1542.41	749.12	2291.53
Percentage changes									
2013	-5.72	15.92	2.45	-5.72	15.92	2.45	-5.72	15.92	2.45
2014	-1.96	0.76	-0.80	-1.96	0.76	-0.80	-1.96	0.76	-0.80
2015	4.52	-3.42	1.07	2.40	-3.42	-0.12	0.69	-3.42	-1.09
2016	2.21	1.85	2.06	2.26	1.85	2.09	2.30	1.85	2.11
2017	0.98	0.02	0.58	1.00	0.02	0.59	1.02	0.02	0.60
2018	1.11	0.01	0.66	1.14	0.01	0.67	1.16	0.01	0.68
2019	1.59	0.01	0.94	1.62	0.01	0.95	1.65	0.01	0.96
Compound growth rate (per cent) -									
2015-2025	1.53	0.41	1.08	1.56	0.41	1.09	1.59	0.41	1.10
2015-2044	1.59	0.20	1.07	1.61	0.20	1.08	1.64	0.20	1.09
HIGH - Levels									
2015	1010.75	739.44	1750.19	990.57	739.44	1730.01	974.20	739.44	1713.65
2016	1048.11	769.62	1817.73	1027.95	769.62	1797.56	1011.62	769.62	1781.24
2017	1073.99	769.93	1843.92	1053.84	769.93	1823.78	1037.55	769.93	1807.49
2018	1099.14	770.16	1869.30	1079.01	770.16	1849.17	1062.75	770.16	1832.91
2019	1127.24	773.55	1900.79	1107.13	773.55	1880.68	1090.91	773.55	1864.46
2020	1159.17	777.19	1936.37	1139.08	777.19	1916.28	1122.91	777.19	1900.10
2025	1332.23	857.27	2189.50	1312.27	857.27	2169.53	1296.33	857.27	2153.60
2030	1486.06	887.70	2373.76	1466.20	887.70	2353.91	1450.49	887.70	2338.20
2035	1648.08	890.12	2538.20	1628.35	890.12	2518.47	1612.88	890.12	2503.00
2040	1790.51	892.67	2683.18	1770.88	892.67	2663.55	1755.62	892.67	2648.29
2044	1921.69	894.96	2816.65	1902.15	894.96	2797.11	1887.08	894.96	2782.04
Compound growth rate (per cent) -									
2015-2025	2.80	1.49	2.26	2.85	1.49	2.29	2.90	1.49	2.31
2015-2044	2.24	0.66	1.65	2.28	0.66	1.67	2.31	0.66	1.68
LOW - Levels									
2015	989.74	669.82	1659.56	969.53	669.82	1639.34	953.09	669.82	1622.91
2016	1003.31	666.02	1669.33	983.10	666.02	1649.12	966.67	666.02	1632.69
2017	1005.22	666.02	1671.24	985.01	666.02	1651.03	968.58	666.02	1634.60
2018	1006.20	666.02	1672.22	985.98	666.02	1652.00	969.55	666.02	1635.57
2019	1007.52	620.22	1627.73	987.30	620.22	1607.51	970.86	620.22	1591.08
2020	1009.83	579.00	1588.83	989.61	579.00	1568.61	973.18	579.00	1552.17
2025	1044.54	563.53	1608.07	1024.34	563.53	1587.87	1007.94	563.53	1571.47
2030	1082.28	563.53	1645.81	1062.10	563.53	1625.64	1045.75	563.53	1609.28
2035	1125.75	563.53	1689.28	1105.60	563.53	1669.14	1089.31	563.53	1652.84
2040	1157.81	563.53	1721.35	1137.68	563.53	1701.22	1121.42	563.53	1684.96
2044	1177.43	563.53	1740.97	1157.31	563.53	1720.85	1141.07	563.53	1704.61
Compound growth rate (per cent) -									
2015-2025	0.54	-1.71	-0.31	0.55	-1.71	-0.32	0.56	-1.71	-0.32
2015-2044	0.60	-0.59	0.17	0.61	-0.59	0.17	0.62	-0.59	0.17

All data are for the Calendar year ending in December of the year specified.

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TABLE 5.10 MAXIMUM SUMMER DEMANDS – TASMANIA (EXCLUDING NON-SCHEDULED HYDRO AND WIND GENERATION)

	SUMMER MAXIMUM DEMAND		
	PERCENTILES		
	10TH	50TH	90TH
	AVERAGE TEMPERATURE(CELSIUS)		
	7.0	8.6	9.8
Unit	**********	MW	***********
BASE			
2011	1286.70	1286.70	1286.70
2012	1329.90	1329.90	1329.90
2013	1236.40	1236.40	1236.40
2014	1267.30	1267.30	1267.30
2015	1212.43	1188.34	1169.53
2016	1234.84	1210.44	1191.38
2017	1272.60	1247.89	1228.60
2018	1282.05	1257.13	1237.69
2019	1292.49	1267.33	1247.71
2020	1306.62	1281.12	1261.24
2025	1400.52	1373.11	1351.79
2030	1487.25	1457.78	1434.89
2035	1604.16	1571.91	1546.94
2040	1706.01	1671.26	1644.39
2045	1817.82	1780.31	1751.36
Percentage changes			
2014	2.50	2.50	2.50
2015	-4.33	-6.23	-7.71
2016	1.85	1.86	1.87
2017	3.06	3.09	3.12
2018	0.74	0.74	0.74
2019	0.81	0.81	0.81
2020	1.09	1.09	1.08
Compound growth rate (per cent) -			
2014-2025	0.91	0.73	0.59
2020-2040	1.34	1.34	1.34
2014-2045	1.17	1.10	1.05
HIGH - Levels			
2015	1253.93	1229.59	1210.58
2016	1285.28	1260.38	1240.96
2017	1351.71	1326.19	1306.31
2018	1373.85	1347.80	1327.51
2019	1395.34	1368.77	1348.08
2020	1421.93	1394.77	1373.64
2025	1606.44	1575.73	1551.91
2030	1819.93	1785.59	1759.04
2035	1983.06	1944.69	1915.11
2040	2122.66	2080.90	2048.76
2045	2277.98	2232.43	2197.43
Compound growth rate (per cent) -			
2014-2025	2.18	2.00	1.86
2020-2040	2.02	2.02	2.02
2014-2045	1.91	1.84	1.79
LOW - Levels			
2015	1164.37	1140.53	1121.90
2016	1178.14	1154.19	1135.48
2017	1191.62	1167.56	1148.76
2018	1193.57	1169.48	1150.66
2019	1194.83	1170.74	1151.91
2020	1150.80	1126.70	1107.86
2025	1123.46	1098.70	1079.37
2030	1156.16	1130.63	1110.70
2035	1201.42	1174.76	1153.98
2040	1233.69	1206.26	1184.91
2045	1261.49	1233.43	1211.58
Compound growth rate (per cent) -			
2014-2025	-1.09	-1.29	-1.45
2020-2040	0.35	0.34	0.34
2014-2045	-0.01	-0.09	-0.14

All data are for the financial year ending in June of the year specified.

TABLE 5.11 MAXIMUM SUMMER DEMANDS – TASMANIA (INCLUDING NON-SCHEDULED GENERATION)

	SUMMER MAXIMUM DEMAND		
	PERCENTILES		
	10TH	50TH	90TH
	AVERAGE TEMPERATURE(CELSIUS)		
	7.0	8.6	9.8
Unit	***********	MW	**********
BASE			
2011	1445.50	1445.50	1445.50
2012	1408.80	1408.80	1408.80
2013	1331.60	1331.60	1331.60
2014	1366.80	1366.80	1366.80
2015	1394.13	1370.04	1351.23
2016	1416.54	1392.14	1373.08
2017	1454.30	1429.59	1410.30
2018	1463.75	1438.83	1419.39
2019	1474.19	1449.03	1429.41
2020	1488.32	1462.82	1442.94
2025	1582.22	1554.81	1533.49
2030	1668.95	1639.48	1616.59
2035	1785.86	1753.61	1728.64
2040	1887.71	1852.96	1826.09
2045	1999.52	1962.01	1933.06
Percentage changes			
2014	2.64	2.64	2.64
2015	2.00	0.24	-1.14
2016	1.61	1.61	1.62
2017	2.67	2.69	2.71
2018	0.65	0.65	0.64
2019	0.71	0.71	0.71
2020	0.96	0.95	0.95
Compound growth rate (per cent) -			
2014-2025	1.34	1.18	1.05
2020-2040	1.20	1.19	1.18
2014-2045	1.23	1.17	1.12
HIGH - Levels			
2015	1435.63	1411.29	1392.28
2016	1466.98	1442.08	1422.66
2017	1533.41	1507.89	1488.01
2018	1555.55	1529.50	1509.20
2019	1577.04	1550.47	1529.78
2020	1603.63	1576.47	1555.34
2025	1788.14	1757.43	1733.61
2030	2001.63	1967.29	1940.74
2035	2164.76	2126.39	2096.81
2040	2304.36	2262.60	2230.46
2045	2459.68	2414.13	2379.13
Compound growth rate (per cent) -			
2014-2025	2.47	2.31	2.18
2020-2040	1.83	1.82	1.82
2014-2045	1.91	1.85	1.80
LOW - Levels			
2015	1346.07	1322.23	1303.60
2016	1359.84	1335.89	1317.18
2017	1373.32	1349.26	1330.46
2018	1375.27	1351.18	1332.36
2019	1376.53	1352.44	1333.61
2020	1332.50	1308.40	1289.56
2025	1305.16	1280.40	1261.07
2030	1337.86	1312.33	1292.40
2035	1383.12	1356.46	1335.68
2040	1415.39	1387.96	1366.61
2045	1443.19	1415.13	1393.28
Compound growth rate (per cent) -			
2014-2025	-0.42	-0.59	-0.73
2020-2040	0.30	0.30	0.29
2014-2045	0.18	0.11	0.06

All data are for the financial year ending in June of the year specified.

TABLE 5.12 MAXIMUM SUMMER DEMANDS – TASMANIA (EXCLUDING NON-SCHEDULED HYDRO GENERATION)

	SUMMER MAXIMUM DEMAND		
	PERCENTILES		
	10TH	50TH	90TH
	AVERAGE TEMPERATURE(CELSIUS)		
	7.0	8.6	9.8
Unit	**********	MW	***********
BASE			
2011	1382.50	1382.50	1382.50
2012	1348.40	1348.40	1348.40
2013	1292.00	1292.00	1292.00
2014	1344.80	1344.80	1344.80
2015	1356.63	1332.54	1313.73
2016	1379.04	1354.64	1335.58
2017	1416.80	1392.09	1372.80
2018	1426.25	1401.33	1381.89
2019	1436.69	1411.53	1391.91
2020	1450.82	1425.32	1405.44
2025	1544.72	1517.31	1495.99
2030	1631.45	1601.98	1579.09
2035	1748.36	1716.11	1691.14
2040	1850.21	1815.46	1788.59
2045	1962.02	1924.51	1895.56
Percentage changes			
2014	4.09	4.09	4.09
2015	0.88	-0.91	-2.31
2016	1.65	1.66	1.66
2017	2.74	2.76	2.79
2018	0.67	0.66	0.66
2019	0.73	0.73	0.73
2020	0.98	0.98	0.97
Compound growth rate (per cent) -			
2014-2025	1.27	1.10	0.97
2020-2040	1.22	1.22	1.21
2014-2045	1.23	1.16	1.11
HIGH - Levels			
2015	1398.13	1373.79	1354.78
2016	1429.48	1404.58	1385.16
2017	1495.91	1470.39	1450.51
2018	1518.05	1492.00	1471.70
2019	1539.54	1512.97	1492.28
2020	1566.13	1538.97	1517.84
2025	1750.64	1719.93	1696.11
2030	1964.13	1929.79	1903.24
2035	2127.26	2088.89	2059.31
2040	2266.86	2225.10	2192.96
2045	2422.18	2376.63	2341.63
Compound growth rate (per cent) -			
2014-2025	2.43	2.26	2.13
2020-2040	1.87	1.86	1.86
2014-2045	1.92	1.85	1.81
LOW - Levels			
2015	1308.57	1284.73	1266.10
2016	1322.34	1298.39	1279.68
2017	1335.82	1311.76	1292.96
2018	1337.77	1313.68	1294.86
2019	1339.03	1314.94	1296.11
2020	1295.00	1270.90	1252.06
2025	1267.66	1242.90	1223.57
2030	1300.36	1274.83	1254.90
2035	1345.62	1318.96	1298.18
2040	1377.89	1350.46	1329.11
2045	1405.69	1377.63	1355.78
Compound growth rate (per cent) -			
2014-2025	-0.54	-0.71	-0.86
2020-2040	0.31	0.30	0.30
2014-2045	0.14	0.08	0.03

All data are for the financial year ending in June of the year specified.

TABLE 5.13 MAXIMUM SUMMER DEMANDS (10TH, 50TH, 90TH PERCENTILES) – TASMANIA (INCLUDING NON-SCHEDULED GENERATION)

	10TH PERCENTILE			50TH PERCENTILE			90TH PERCENTILE		
	EXCLUDING MAJOR LOAD	MAJOR LOAD & SMALL MAJORS	TOTAL	EXCLUDING MAJORS	MAJOR LOAD & SMALL MAJORS	TOTAL	EXCLUDING MAJORS	MAJOR LOAD & SMALL MAJORS	TOTAL
Unit	*******************			MW	*******************				
BASE									
2011	745.00	700.50	1445.50	745.00	700.50	1445.50	745.00	700.50	1445.50
2012	679.77	729.03	1408.80	679.77	729.03	1408.80	679.77	729.03	1408.80
2013	623.88	707.72	1331.60	623.88	707.72	1331.60	623.88	707.72	1331.60
2014	644.74	722.06	1366.80	644.74	722.06	1366.80	644.74	722.06	1366.80
2015	689.98	704.14	1394.13	665.90	704.14	1370.04	647.09	704.14	1351.23
2016	712.24	704.30	1416.54	687.84	704.30	1392.14	668.79	704.30	1373.08
2017	736.96	717.34	1454.30	712.25	717.34	1429.59	692.97	717.34	1410.30
2018	746.26	717.48	1463.75	721.35	717.48	1438.83	701.90	717.48	1419.39
2019	756.64	717.55	1474.19	731.48	717.55	1449.03	711.86	717.55	1429.41
2020	770.68	717.63	1488.32	745.19	717.63	1462.82	725.31	717.63	1442.94
2025	848.93	733.29	1582.22	821.53	733.29	1554.81	800.20	733.29	1533.49
2030	933.49	735.46	1668.95	904.02	735.46	1639.48	881.13	735.46	1616.59
2035	1043.65	742.20	1785.86	1011.41	742.20	1753.61	986.43	742.20	1728.64
2040	1144.46	743.25	1887.71	1109.71	743.25	1852.96	1082.84	743.25	1826.09
2045	1254.74	744.78	1999.52	1217.23	744.78	1962.01	1188.28	744.78	1933.06
Percentage changes									
2014	3.34	2.03	2.64	3.34	2.03	2.64	3.34	2.03	2.64
2015	7.02	-2.48	2.00	3.28	-2.48	0.24	0.36	-2.48	-1.14
2016	3.23	0.02	1.61	3.29	0.02	1.61	3.35	0.02	1.62
2017	3.47	1.85	2.67	3.55	1.85	2.69	3.62	1.85	2.71
2018	1.26	0.02	0.65	1.28	0.02	0.65	1.29	0.02	0.64
2019	1.39	0.01	0.71	1.41	0.01	0.71	1.42	0.01	0.71
2020	1.86	0.01	0.96	1.87	0.01	0.95	1.89	0.01	0.95
Compound growth rate (per cent) -									
2014-2025	2.53	0.14	1.34	2.23	0.14	1.18	1.98	0.14	1.05
2020-2040	2.00	0.18	1.20	2.01	0.18	1.19	2.02	0.18	1.18
2014-2045	2.17	0.10	1.23	2.07	0.10	1.17	1.99	0.10	1.12
HIGH - Levels									
2015	700.25	735.38	1435.63	675.91	735.38	1411.29	656.90	735.38	1392.28
2016	731.30	735.68	1466.98	706.40	735.68	1442.08	686.98	735.68	1422.66
2017	767.75	765.66	1533.41	742.24	765.66	1507.89	722.35	765.66	1488.01
2018	789.59	765.96	1555.55	763.54	765.96	1529.50	743.25	765.96	1509.20
2019	810.87	766.17	1577.04	784.30	766.17	1550.47	763.60	766.17	1529.78
2020	834.28	769.35	1603.63	807.12	769.35	1576.47	785.99	769.35	1555.34
2025	975.63	812.52	1788.14	944.91	812.52	1757.43	921.09	812.52	1733.61
2030	1120.49	881.14	2001.63	1086.14	881.14	1967.29	1059.60	881.14	1940.74
2035	1280.86	883.90	2164.76	1242.49	883.90	2126.39	1212.91	883.90	2096.81
2040	1418.30	886.07	2304.36	1376.54	886.07	2262.60	1344.40	886.07	2230.46
2045	1570.81	888.87	2459.68	1525.26	888.87	2414.13	1490.26	888.87	2379.13
Compound growth rate (per cent) -									
2014-2025	3.84	1.08	2.47	3.54	1.08	2.31	3.30	1.08	2.18
2020-2040	2.69	0.71	1.83	2.71	0.71	1.82	2.72	0.71	1.82
2014-2045	2.91	0.67	1.91	2.82	0.67	1.85	2.74	0.67	1.80
LOW - Levels									
2015	679.91	666.16	1346.07	656.07	666.16	1322.23	637.44	666.16	1303.60
2016	693.68	666.16	1359.84	669.73	666.16	1335.89	651.02	666.16	1317.18
2017	710.94	662.38	1373.32	686.88	662.38	1349.26	668.08	662.38	1330.46
2018	712.89	662.38	1375.27	688.80	662.38	1351.18	669.99	662.38	1332.36
2019	714.15	662.38	1376.53	690.06	662.38	1352.44	671.23	662.38	1333.61
2020	715.67	616.83	1332.50	691.57	616.83	1308.40	672.73	616.83	1289.56
2025	743.92	561.24	1305.16	719.16	561.24	1280.40	699.83	561.24	1261.07
2030	776.63	561.24	1337.86	751.09	561.24	1312.33	731.16	561.24	1292.40
2035	821.88	561.24	1383.12	795.22	561.24	1356.46	774.45	561.24	1335.68
2040	854.15	561.24	1415.39	826.73	561.24	1387.96	805.37	561.24	1366.61
2045	881.95	561.24	1443.19	853.89	561.24	1415.13	832.04	561.24	1393.28
Compound growth rate (per cent) -									
2014-2025	1.31	-2.26	-0.42	1.00	-2.26	-0.59	0.75	-2.26	-0.73
2020-2040	0.89	-0.47	0.30	0.90	-0.47	0.30	0.90	-0.47	0.29
2014-2045	1.02	-0.81	0.18	0.91	-0.81	0.11	0.83	-0.81	0.06

All data are for the financial year ending in June of the year specified.

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[redacted]

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6. PeakSim's maximum demand projections

TasNetworks has commissioned the National Institute of Economic and Industry Research ('the National Institute') to prepare projections of summer and winter maximum demands for TasNetworks' demand using the National Institute's PeakSim Model.

6.1 Background

The PeakSim model has evolved out a number of lines of research at the National Institute. The key initial research began several years ago with a request to provide greater information about the probabilistic nature of seasonal maximum demands. This research pulled together earlier work undertaken by the National Institute in the 1990s and work done by various planning body in Australia and around the world.

The PeakSim model generates probability distributions of peak demand from synthetically generated distributions of temperature and demand. This contrast with more deterministic model that conditions peak demand forecasts on given temperature levels.

PeakSim is based on an intuitive conceptual framework. Maximum demand can be segmented into two parts:

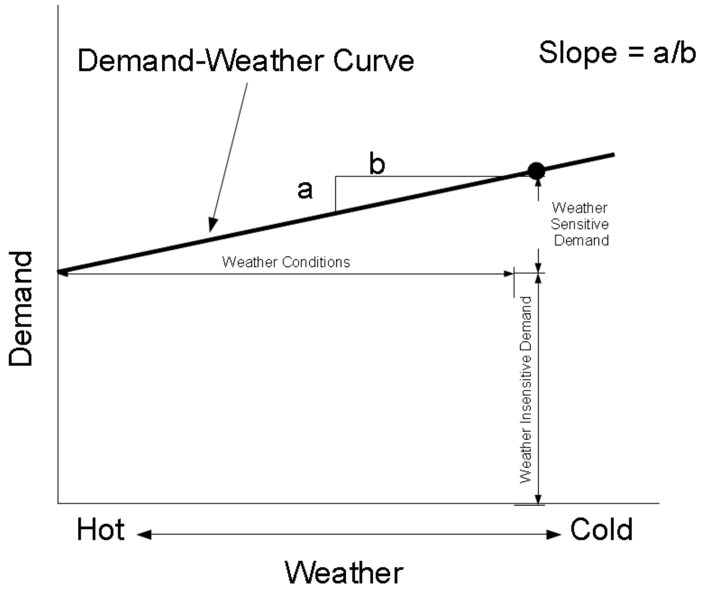
- weather insensitive demand; and
- weather sensitive demand.

Weather insensitive demand is the part of demand that would occur irrespective of the weather conditions. The level of weather insensitive demand is roughly approximated by demand on a mild weather day (all other factors held constant). Weather sensitive demand is the part of demand that occurs due to the prevailing weather conditions. This part of demand reflects the intensity of heating/cooling equipment use. The level of weather sensitive demand can vary significantly depending on the prevailing weather conditions.

The figure below provides a simplified illustration of the segmentation of demand between the weather insensitive demand and weather sensitive demand.[2] This diagram is a hypothetical illustration only. It characterises weather insensitive demand as a greater proportion of total demand. In many instances, the weather sensitive demand can account for a much larger proportion of overall demand than is illustrated here. The relative proportion of weather-sensitive and insensitive demand will depend on the composition of residential, commercial and industrial customers within the customer base.

[2] The diagram shows the relationship between demand-weather as linear. This is for illustrative purposes only.

Figure 6.1: Electricity demand and weather relationship during a typical summer



The proportions of weather insensitive demand and weather sensitive demand can be estimated (for any given year) using regression analysis.[3] Specifically, the weather insensitive part of demand can be inferred from the intercept and the weather sensitive part can be inferred from the product of the temperature coefficient (the slope) and the temperature variable.[4]

The PeakSim model uses half-hourly demand and temperature data. Each half-hourly period during the day is modelled separately to capture the intra-daily dynamics between demand and temperature.

As the economy evolves and the use and stock of electrical equipment increases, the intercept and temperature coefficients will change accordingly. Forward estimates of intercept and weather coefficients are the key drivers of the maximum demand projections. The intercept is projected forward using estimated future growth in underlying economic factors like population growth and economic activity. The temperature coefficient is projected forward using forecasts of air-conditioning stock and other temperature sensitive equipment. The National Institute monitors and forecasts air conditioner sales and this information is incorporated into the PeakSim model.

Maximum demand is the highest level of demand recorded within a given period.[5] Maximum demand event typically arise during periods of extreme weather conditions. These events are difficult to predict in advance, largely because the severity of weather extremes can vary significantly from year to year. For this reason, maximum demand projections are presented as a probability distribution of possible maximum demand levels (i.e. probability of exceedance levels). This report focuses on projected maximum demand for three key probability levels; 10%, 50% and 90%.[6] The probability distribution generated by PeakSim captures the impacts of different weather extremes and general randomness of consumer behaviour on maximum demand events.

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3 Temperature can be used as general indicator of prevailing weather conditions.

4 Electricity demand has a greater range of influences than prevailing weather conditions. Many consumer activities routinely occur at certain points during the day or week. Therefore, electricity demand varies significantly across periods, independently of weather conditions. The regression analysis can be easily structured to account for these 'routine' factors.

5 Highest half-hourly demand reading.

6 The model underlying these three projections generates projections for the full spectrum of probability levels.

In this modelling exercise, we employ a simulation method called 'bootstrapping' to generate the probability distributions. This involves sampling historical temperature data and regression residual estimates to generate a large number of synthetic sequences of temperature and the residuals.[7] These synthetic sequences are then feed back into the estimated demand-temperature equations to generate synthetic sequences of demand.

Synthetic distributions of demand for each half hour period are generated from the estimated models using synthetically-generated temperature and residual series. Synthetic temperature series are generated from historical temperature data using sampling methods that preserve the observed patterns in the historical data and allow for the effects of urban and global warming on recent and future climatic conditions. Similarly, synthetic residuals series are generated using sampling methods that ensure consistency with the model structure and the historical events.

The highest readings from each synthetic demand sequence are identified. These readings represent feasible levels of maximum demand and form the basis of the maximum demand probability distribution. The 90th, 50th and 10th percentile values of the highest readings are the 10%, 50% and 90% probability of exceedance levels, respectively. Probability of exceedance levels are separately generated for each forecast year using the respective year's projected demand-temperature equation.

In additional to the conventional metrics of 10%, 50% and 90% probability of exceedance levels, the PeakSim model can generates projections for the full probability spectrum.

[7] The residuals provide a proxy measure of the randomness of consumer behaviour. The residuals may also capture errors arising from the modeling process, namely model specification, measurement and sampling errors. As long as these errors are not idiosyncratic, the residuals can be representative of the random elements of consumer behaviour. See National Institute of Economic and Industry Research (2006) 'Modelling of synthetic demand and temperature data' published in Electricity Supply Industry Planning Council, Annual Planning Review, Appendix 4 (Section 4, pages 143-148) for further discussion.

6.2 Data and assumptions

TasNetworks provided the National Institute with half-hourly readings of network electricity demand spanning the period July 1987 to October 2014 for Tasmania. The Tasmanian network demand encompasses:

1. direct-supplied customers; and
2. distribution-supplied customers;

TasNetworks also separately supplied half-hourly readings for the direct-supplied customers (among other data) allowing the distribution-supplied customers to be implied.

Segments	Sample period
TasNetworks Data	July 1987 to October 2014
Major Direct-supplied customers	July 1999 to October 2014
Small Direct-supplied Customers	Jan 2008 to October 2014
Distribution supplied Customers	Jan 2008 to October 2014

The National Institute independently obtained:

- confidential air conditioning sales data from industry sources; and
- half-hourly and daily readings of air temperature at various weather stations (below) from the Australian Bureau of Meteorology.

Area[8]	Daily data	Half-hourly data
Tasmania	Hobart (Ellerslie Road)	Hobart (Ellerslie Road)

The National Institute has also utilised information/data from a range of other third party sources including:

- government statistical/research bodies (Australian Bureau of Statistics, Bureau of Resource and Energy Economics);
- government department and agencies; and
- other research and consulting organisations.

As with any modelling exercise, a number of assumptions need to be made to generate a set of projections. It has been assumed that (among other things):

- economic conditions will be consistent with those set out earlier in this report;
- normal or standard seasonal weather conditions (consistent with recent history records) will prevail over the projection period; and
- demand is not constrained or impacted by network supply events (i.e. outages, transfers and other types of disruption planned or unforeseen).

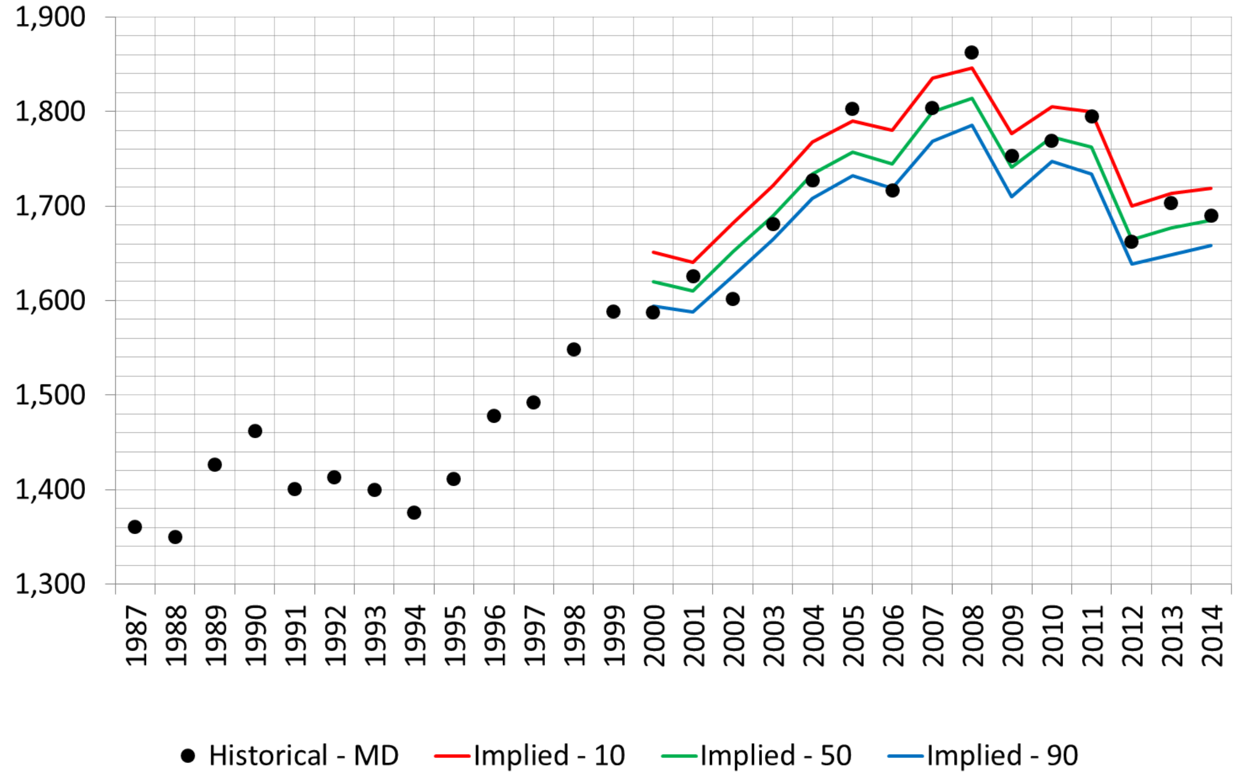
[8] Due to data limitation, data from a more localised weather station could not be used in the simulation modelling. Despite this, the chosen weather station provides a very representative measure of prevailing weather conditions in the area.

6.3 Implied historical PoE levels

Figures 6.2 and 6.3 shows (respectively) recent winter and summer maximum demands relative to 10%, 50% and 90% probability of exceedance levels estimated from simulation modelling of demand and temperature.

Due to limited and inconsistent weather data on a half-hourly basis, implied probability of exceedance for years prior to 1999 could not be estimated.

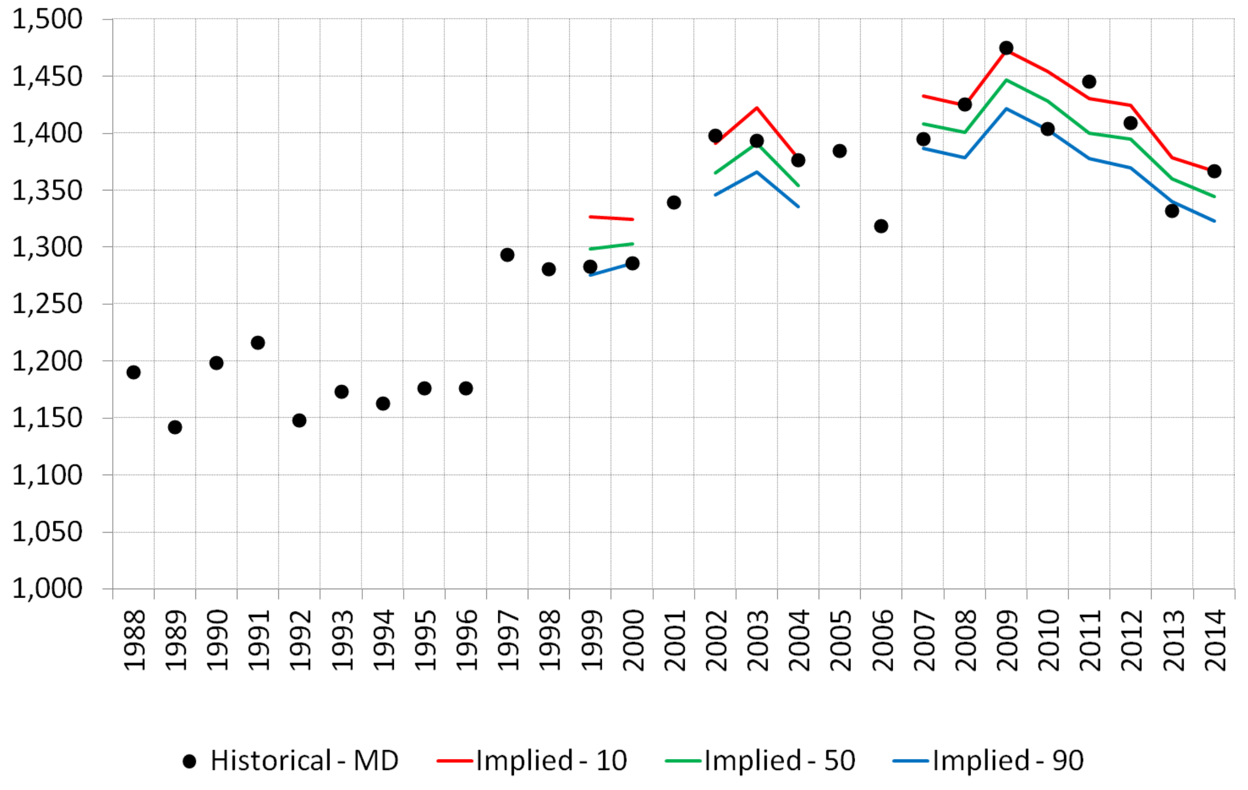
Figure 6.2: Implied historical probability of exceedance level and observed winter maximum demand (MW)



Based on this modelling, the 2014 winter maximum demand of 1,689 was approximately a 44 per cent probability of exceedance event. A 10 per cent probability of exceedance event would have been a maximum demand of 1718 MW.[9]

[9] This estimate is based on the prevailing economic and seasonal conditions and the underlying stock of electrical appliance and equipment.

Figure 6.3: Implied historical probability of exceedance level and observed summer maximum demand (MW)



Due to inconsistency in the half-hourly electricity data in certain periods, implied probability of exceedance for some summers could not be accurately estimated.

Based on this modelling, the 2013-14 summer maximum demand of 1,367 MW was approximately a 9 per cent probability of exceedance event.[10]

[10] This estimate is based on the prevailing economic and seasonal conditions and the underlying stock of electrical appliance and equipment.

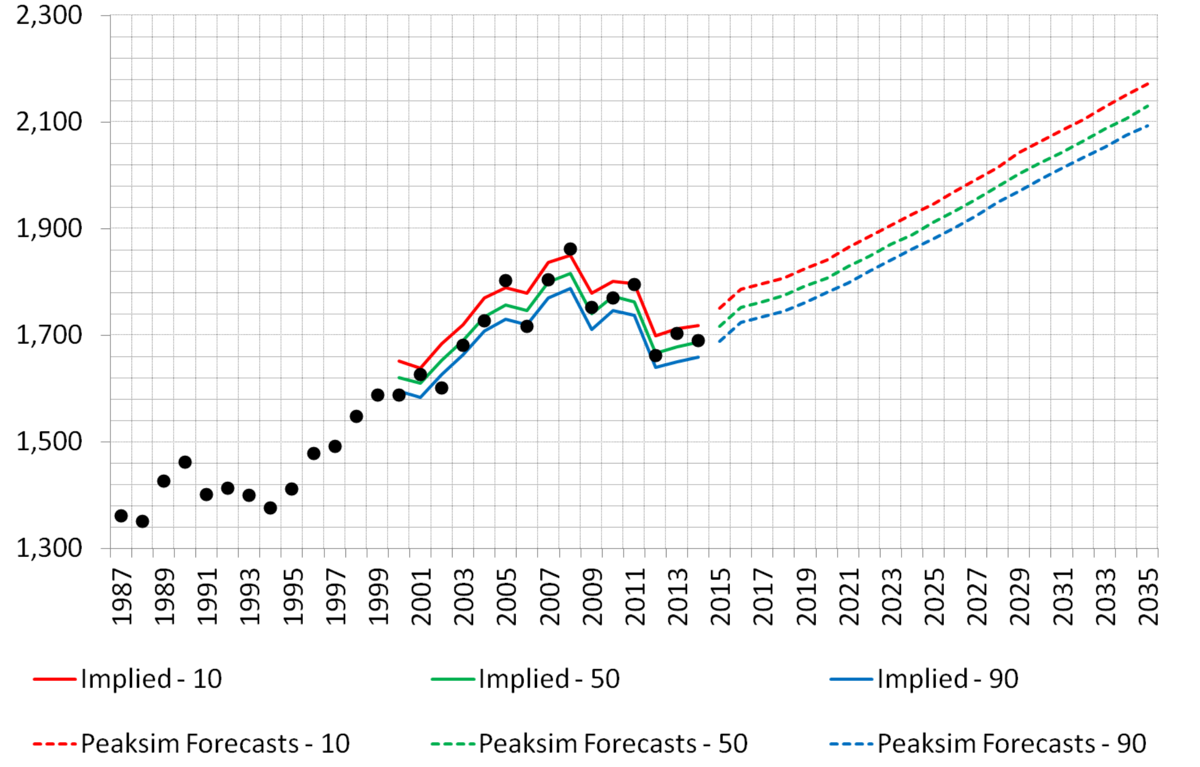
6.4 Projections

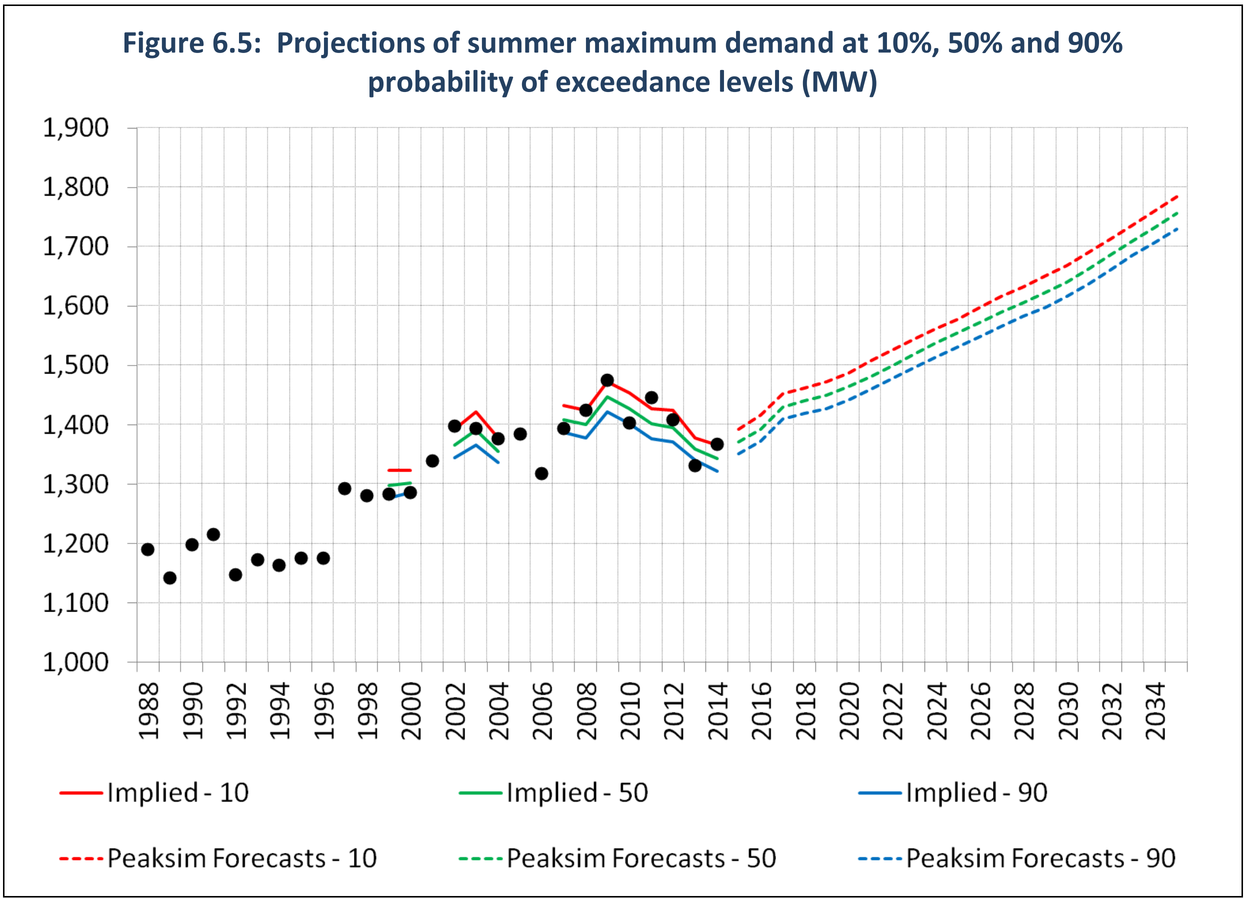
Figures 6.4 and 6.5 present projections of maximum demand under a base economic scenario for winter and summer (respectively) for Tasmania.

Winter maximum demand at 10% probability of exceedance level is projected to increase, on average, by around 1.22 per cent per annum over the next ten years.

Summer maximum demand at 10% probability of exceedance level is projected to increase, on average, by around 1.44 per cent per annum over the next ten year

Figure 6.4: Projections of winter maximum demand at 10%, 50% and 90% probability of exceedance levels (MW)





Projections of non-coincident maximum demand have been also separately estimated for distribution area segment of Tasmanian Network Demand. Tables 6.1 and 6.2 present the non-coincidence maximum demand projections for both Tasmanian Network Demand and Distribution Area Demand and for winter and summer (respectively).

Table 6.1	Projections of winter (non-coincidence) maximum demand for key segment																
Segment	**Measure***	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Tasmanian Network Demand	10% PoE	1,778	1,801	1,797	1,698	1,713	1,718	1750	1786	1797	1808	1825	1841	1864	1885	1906	1928
	50% PoE	1,741	1,773	1,763	1,667	1,678	1,686	1717	1752	1763	1774	1792	1808	1829	1849	1871	1889
	90% PoE	1,711	1,746	1,737	1,639	1,650	1,658	1688	1723	1734	1745	1761	1780	1798	1821	1841	1861
	Observed	1,753	1,769	1,795	1,662	1,703	1,689										
	Implied PoE	31	56	11	59	17	44										
Distribution Area Demand	10% PoE	1161	1142	1104	1078	1027	1018	1060	1084	1091	1101	1118	1134	1152	1168	1185	1199
	50% PoE	1123	1110	1072	1045	996	991	1032	1053	1061	1071	1089	1104	1122	1136	1154	1168
	90% PoE	1093	1083	1043	1017	971	967	1008	1029	1035	1047	1065	1076	1095	1111	1125	1141
	Observed	1098	1071	1076	1053	1006	990										
	Implied PoE	85	96	44	36	37	53										

Note: * 10%, 50%, 90% PoE and Observed estimates are expressed in MWs. Implied PoE estimates are expressed as percentages.

Table 6.2	Projections of summer (non-coincidence) maximum demand for each segment																
Segment	**Measure***	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Tasmanian Network Demand	10% PoE	1473	1454	1427	1424	1378	1366	1392	1417	1453	1463	1473	1487	1507	1526	1545	1562
	50% PoE	1447	1427	1402	1395	1360	1344	1371	1393	1430	1441	1450	1464	1481	1500	1520	1538
	90% PoE	1423	1403	1377	1371	1341	1322	1351	1373	1410	1419	1427	1442	1460	1478	1496	1514
	Observed	1475	1404	1445	1409	1332	1367										
	Implied PoE	9	89	1	29	98	9										
Distribution Area Demand	10% PoE	780	742	738	701	691	696	718	741	770	778	791	805	820	837	854	871
	50% PoE	755	720	717	683	673	677	699	723	749	758	769	783	799	816	831	848
	90% PoE	733	700	697	664	656	661	683	705	731	739	750	763	780	795	812	826
	Observed	776	704	762	697	667	677										
	Implied PoE	14	85	2	15	67	50										

Note: * 10%, 50%, 90% PoE and Observed estimates are expressed in MWs. Implied PoE estimates are expressed as percentages.

Appendix A: Explanation of forecast input

Set out below are the explanations of forecast input that shows which factors have been considered in the forecast.

	Maximum demand forecast				Energy sales forecast					
Input variable	**Retail Base**	**Retail High and Low**	**Direct supplied customers Base**	**Direct supplied customers High and Low**	**Retail Base**	**Retail High and Low**	**Direct supplied customers Base**	**Direct supplied customers High and Low**	**Source of information**	**Reference**
1. GSP	NIEIR	NIEIR			NIEIR	NIEIR			NIEIR economic forecast – macro forecast NIEIR economic analysis	Appendix 1
❖ Private consumption									Component of GSP but not directly used	
❖ Private dwelling investment									Component of GSP but not directly used	
❖ Private non-dwelling constant investment									Component of GSP but not directly used	
❖ Private equipment investment									Component of GSP but not directly used	
❖ Government consumption									Component of GSP but not directly used	
❖ State financial demand									Component of GSP but not directly used	
❖ Overseas exports									Component of GSP but not directly used	
❖ Overseas imports									Component of GSP but not directly used	
❖ Wages, salaries and supplements									Component of GSP but not directly used	
❖ GSP deflator base year 2006-07									Component of GSP but not directly used	
❖ Consumer Price Index 1989-90					NIEIR	NIEIR				
❖ Employment									Component of GSP but not directly used	
❖ Labour force participation rate									Component of GSP but not directly used	
❖ Unemployment rate									Component of GSP but not directly used	
❖ Civilian working age population									Component of GSP but not directly used	
❖ Population									Component of GSP but not directly used	
❖ Net overseas migration									Component of GSP but not directly used	
❖ Number of households									Dwelling stock NIEIR forecast	
Sector										
1. Agriculture, forestry and fishery					NIEIR	NIEIR			NIEIR economic forecast	
2. Mining					NIEIR	NIEIR			NIEIR economic forecast	
3. Food, beverages and tobacco					NIEIR	NIEIR			NIEIR economic forecast	
4. Textile, clothing, footwear & leather					NIEIR	NIEIR			NIEIR economic forecast	
5. Wood, paper products, printing, publishing and recorded media					NIEIR	NIEIR			NIEIR economic forecast	
6. Petroleum, coal and chemicals					NIEIR	NIEIR			NIEIR economic forecast	
7. Non-metallic products					NIEIR	NIEIR			NIEIR economic forecast	
8. Metal products					NIEIR	NIEIR			NIEIR economic forecast	
9. Machinery and equipment					NIEIR	NIEIR			NIEIR economic forecast	
10. Electricity					NIEIR	NIEIR			NIEIR economic forecast	
11. Gas					NIEIR	NIEIR			NIEIR economic forecast	
12. Water					NIEIR	NIEIR			NIEIR economic forecast	
13. Construction					NIEIR	NIEIR			NIEIR economic forecast	
14. All services					NIEIR	NIEIR			NIEIR economic forecast	
Other variables										
Electricity prices					NIEIR	NIEIR			AEMO price forecast	
Temperature	BOM	BOM			BOM	BOM			Bureau of Meteorology	
Historic values	TasNetworks	TasNetworks	TasNetworks	TasNetworks	Aurora	Aurora	TasNetworks	TasNetworks		
Company information			NIEIR/ TasNetworks	NIEIR/ TasNetworks			NIEIR/ TasNetworks	NIEIR/ TasNetworks	Company website/industry intelligence	
Customer forecast via TasNetworks			TasNetworks	TasNetworks			TasNetworks	TasNetworks	Contractual values based on TasNetworks	
International and domestic outlook	NIEIR									

Appendix B: Backcasting the Tasmanian winter MD

The Tasmanian MD back-projections:

- daily reference temperature conditions; and
- were calculated by NIEIR and are based on actual economic conditions.

The Tasmanian actual MDs represent total actual demands, including major industrial loads. Variations in major industrial loads could contribute up to around 40 MW to the backcasting error, although more typically it is around 30 MW.

There is no correction to the actual MDs for time of day effects as the Tasmanian winter MD virtually always occurs at 8:30 a.m. and 9:00 a.m.

Figure B.1 compares the Tasmanian actual winter MDs with the Tasmanian winter back-projections. This figure uses calculations that involve using the actual temperatures at system maximum demand and therefore represents a comparison of actual with fitted. In other words, it is effectively an ex-post forecast comparison where the actual values of the independent variables are used in the calculation.

Figure B.1: Actual and fitted winter maximum demands (MDs) – 1991 to 2014

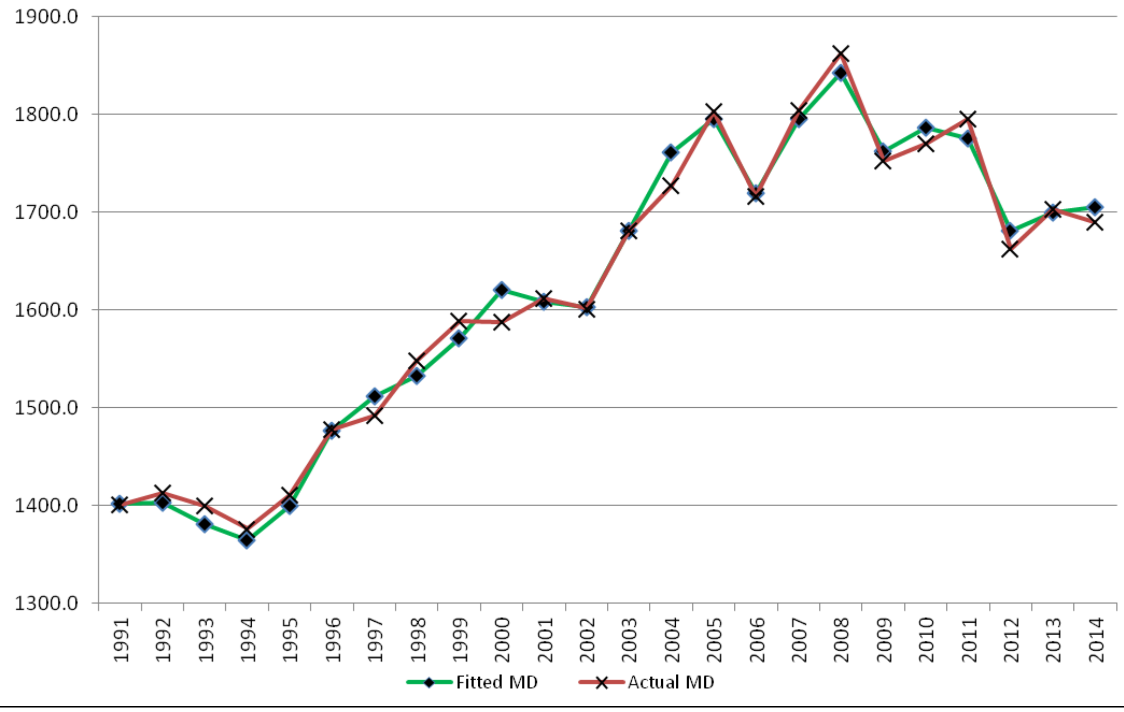
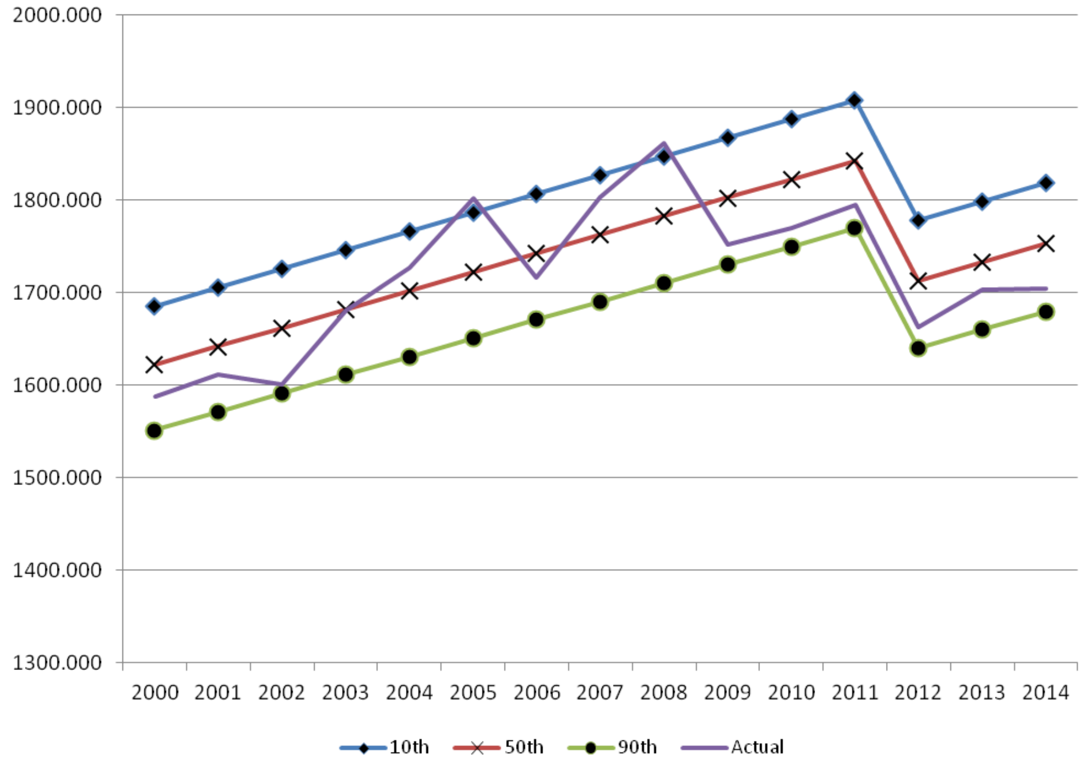


Figure B.2 shows an alternative representation of the forecast equation, where instead of using the actual temperatures at system MD the POE temperatures for winter are used to generate the 10th, 50th and 90th backward looking demands. The two extremes, the 10th and 90th POE demand lines, are also adjusted for the average variability in major load demand at system MD. That is, 35 MW is added to the 10th POE and 35 MW deducted from the 90th POE demand. In 2009 the global financial crisis led one MI customer to cut their load by around 50 per cent.

Figure B.2: Comparison of actual winter MDs with 10th, 50th and 90th backward projections



Note: Adjusted for TEMCO low reading at System MD in 2012.

Table B.1 shows the actual temperatures and POE levels (based on temperature) associated with Tasmanian winter maximum demands.

Table B.1	Actual temperatures and POE level based on temperature at winter MD	
	POE temperature on peaks (Celsius)	Percentile (per cent)
1998	2.2	53th
1999	4.2	100th
2000	2.8	79th
2001	2.4	56th
2002	2.96	87th
2003	4.0	100rd
2004	3.1	88rd
2005	2.5	67th
2006	4.6	100th
2007	1.6	28th
2008	4.3	100th
2009	3.6	96nd
2010	3.5	94th
2011	2.6	75th
2012	3.7	97th
2013	3.4	92nd
2014	3.9	98th

Appendix C: Forecast evaluation and errors

The following error calculation formulae were supplied by AEMO from an unknown source.

Suppose the forecast sample is $j = T+1, T+2, \ldots, T+h$, and denote the actual and forecasted value in period t as y_t and $\hat{y}_t$, respectively. The reported forecast error statistics are computed as follows:

Root Mean Squared Error	$\sqrt{\sum_{t=T+1}^{T+h} (\hat{y}_t - y_t)^2/(h+1)}$
Mean Absolute Error	$\sum_{t=T+1}^{T+h} \lvert \hat{y}_t - y_t \rvert/(h+1)$
Mean Absolute Percentage Error	$\sum_{t=T+1}^{T+h} \left\lvert \frac{\hat{y}_t - y_t}{y_t} \right\rvert/(h+1)$
Theil Inequality Coefficient	$\dfrac{\sqrt{\sum_{t=T+1}^{T+h} (\hat{y}_t - y_t)^2/(h+1)}}{\sqrt{\sum_{t=T+1}^{T+h} \hat{y}_t^{\,2}/(h+1)} + \sqrt{\sum_{t=T+1}^{T+h} y_t^{\,2}/(h+1)}}$

The first two forecast error statistics depend on the scale of the dependent variable. These should be used as relative measures to compare forecasts for the same series across different models; the smaller the error, the better the forecasting ability of that model according to that criterion. The remaining two statistics are scale invariant. The Theil inequality coefficient always lies between zero and one, where zero indicates a perfect fit.

The mean squared forecast error can be decomposed as:

The mean squared forecast error can be decomposed as

$$\sum(\hat{y}_t - y_t)^2/h = ((\sum \hat{y}_t/h) - \bar{y})^2 + (s_{\hat{y}} - s_y)^2 + 2(1-r)s_{\hat{y}}s_y \qquad (14.5)$$

where $\sum \hat{y}_t/h$, $\bar{y}$, $s_{\hat{y}}$, s_y are the means and (biased) standard deviations of $\hat{y}_t$ and y, and r is the correlation between $\hat{y}_t$ and y. The proportions are defined as:

Bias Proportion	$\dfrac{\left(\left(\sum \hat{y}_t / h\right) - \bar{y}\right)^2}{\sum (\hat{y}_t - y_t)^2 / h}$
Variance Proportion	$\dfrac{(s_{\hat{y}} - s_y)^2}{\sum (\hat{y}_t - y_t)^2 / h}$
Covariance Proportion	$\dfrac{2(1-r) s_{\hat{y}} s_y}{\sum (\hat{y}_t - y_t)^2 / h}$

- The bias proportion tells us how far the mean of the forecast is from the mean of the actual series.
- The variance proportion tells us how far the variation of the forecast is from the variation of the actual series.
- The covariance proportion measures the remaining unsystematic forecasting errors.

Note that the bias, variance and covariance proportions add up to one.

If your forecast is “good”, the bias and variance proportions should be small so that most of the bias should be concentrated on the covariance proportions.

Table C.1 RMSE					
	Fitted P	Actual A	Error	Per cent error	Squared error
1991	1402.1	1401.0	1.1	0.0	1.3
1992	1403.3	1413.0	-9.7	0.0	94.4
1993	1381.3	1400.0	-18.7	0.0	350.7
1994	1364.1	1376.0	-11.9	0.0	141.9
1995	1399.2	1411.0	-11.8	0.0	138.9
1996	1476.9	1478.0	-1.1	0.0	1.2
1997	1511.4	1492.0	19.4	0.0	377.1
1998	1532.7	1548.0	-15.3	0.0	234.7
1999	1571.0	1588.3	-17.3	0.0	298.0
2000	1621.0	1587.4	33.6	0.0	1131.1
2001	1608.0	1612.1	-4.1	0.0	16.5
2002	1602.5	1601.3	1.3	0.0	1.6
2003	1681.4	1680.6	0.8	0.0	0.6
2004	1760.8	1726.9	33.9	0.0	1147.0
2005	1795.5	1802.6	-7.0	0.0	49.7
2006	1719.7	1716.1	3.6	0.0	12.8
2007	1795.7	1803.5	-7.9	0.0	61.8
2008	1842.7	1862.1	-19.3	0.0	374.2
2009	1762.7	1752.6	10.1	0.0	101.3
2010	1786.3	1770.2	16.1	0.0	258.5
2011	1775.6	1794.8	-19.2	0.0	369.3
2012	1681.1	1662.4	18.7	0.0	350.3
2013	1699.2	1703.1	-3.9	0.0	15.4
2014	1705.1	1689.5	15.6	0.0	243.2
All years					
Sum of squared errors (SSE)					5771.4
Mean of SSE					240.5
RMSE = Square Root – all years					15.5
10 years – 2004-2013					
Sum of squared errors(SSE)					1836.5
Mean of SSE					183.6
RMSE = Square Root					
RMSE- 10 years					13.6

Table C.2	Theil's inequality coefficient calculations										
				Standard deviations – whole sample				Standard deviations – 10 year sample			
P-A	(P-A)^2	p^2	A^2	A-Mean A	Squared	P-Mean P	Squared	A-Mean A	Squared	P-Mean P	Squared
1.1	1.3	1965972.7	1962801.0	-218.7	47822.8	-217.8	47453.9				
-9.7	94.4	1969208.7	1996569.0	-206.7	42718.4	-216.7	46952.7				
-18.7	350.7	1907916.9	1960000.0	-219.7	48261.2	-238.7	56976.3				
-11.9	141.9	1860741.1	1893376.0	-243.7	59382.0	-255.9	65475.0				
-11.8	138.9	1957799.4	1990921.0	-208.7	43549.1	-220.8	48733.6				
-1.1	1.2	2181261.2	2184484.0	-141.7	20074.4	-143.1	20466.5				
19.4	377.1	2284384.2	2226064.0	-127.7	16303.3	-108.6	11783.7				
-15.3	234.7	2349103.6	2396304.0	-71.7	5138.6	-87.3	7619.9	-207.7	43135.9	-223.7	50031.5
-17.3	298.0	2468037.5	2522579.4	-31.4	987.3	-49.0	2398.2	-167.4	28032.5	-185.4	34357.2
33.6	1131.1	2627622.6	2519721.3	-32.3	1044.7	1.0	1.0	-168.3	28334.6	-135.4	18322.7
-4.1	16.5	2585712.2	2598785.8	-7.6	57.9	-12.0	142.9	-143.6	20625.8	-148.3	22005.0
1.3	1.6	2568141.1	2564120.1	-18.4	338.5	-17.4	303.8	-154.4	23840.9	-153.8	23658.7
0.8	0.6	2827026.1	2824321.1	60.9	3707.3	61.4	3770.6	-75.1	5643.1	-75.0	5621.9
33.9	1147.0	3100457.2	2982336.7	107.3	11504.7	140.8	19836.1	-28.7	826.4	4.5	19.9
-7.0	49.7	3223895.3	3249254.5	182.9	33446.8	175.6	30817.9	46.9	2197.4	39.2	1533.9
3.6	12.8	2957276.1	2944968.0	96.4	9294.2	99.7	9940.6	-39.6	1568.2	-36.7	1345.6
-7.9	61.8	3224480.2	3252782.6	183.9	33805.6	175.7	30875.1	47.9	2290.1	39.3	1546.7
-19.3	374.2	3395596.3	3467258.2	242.4	58744.8	222.7	49614.8	106.4	11313.6	86.4	7457.8
10.1	101.3	3107143.6	3071764.1	133.0	17678.5	142.7	20374.3	-3.0	9.3	6.4	40.4
16.1	258.5	3190930.7	3133750.2	150.6	22667.1	166.3	27671.3	14.5	211.7	30.0	897.7
-19.2	369.3	3152692.2	3221307.0	175.1	30665.5	155.6	24215.0	39.1	1529.4	19.2	369.7
18.7	350.3	2826148.6	2763573.8	42.7	1824.6	61.1	3738.7	-93.3	8703.4	-75.2	5661.1
-3.9	15.4	2887199.2	2900549.6	83.4	6958.2	79.2	6273.5	-52.6	2765.9	-57.2	3269.5
15.6	243.2	2907249.9	2854308.9	69.8	4870.0	85.1	7241.2	-66.2	4385.3	-51.3	2630.7

Table C.2	Theil's inequality coefficient calculations (continued)										
				Standard deviations – whole sample				Standard deviations – 10 year sample			
P-A	(P-A)^2	p^2	A^2	A-Mean A	Squared	P-Mean P	Squared	A-Mean A	Squared	P-Mean P	Squared
All years											
sum	5771.4	63525996.8	63481900.1		520845.5		542676.6		34974.5		24753.1
divide by nobs	240.5	2646916.5	2645079.2		21701.9		22611.5		3497.4		2475.3
Sqrt	15.5	1626.9	1626.4		147.3		150.4		59.1		49.8
	fitted	actual									
Means/averages	1620.0	1619.7									
Standard deviation	153.61	150.48									
Covariance	22611.53	21701.90	22036.52								
Theil's inequality coefficient	0.0048										
Correlation coeff	0.9948	0.9948	check								
Bias	0.0003										
Variance	0.0388										
Covariance	0.9608	0.9608	check								
10 years – 2004-2013											
Sum	1836.49	30872612.16	30859516.81								
Divide by nobs	183.65	3087261.22	3085951.68								
Sqrt	13.55	1757.06	1756.69								
	fitted	fitted									
Means/averages	1756.36	1755.69									
Standard deviation	59.14	49.75									
Covariance	2475.31	4921.71	2799.17								
Theil's inequality coefficient	0.0039										
Correlation coeff	0.9838	0.8020	check								
Bias	0.0024										
Variance	0.4798										
Covariance	0.5178	0.5178	check								

Note: The bias, variance and covariance must sum to 1 so the covariance component is just the residual.

Appendix D: Energy MD projections for Tasmania for the next 30 years

Table D.1	Electricity sales by class (GWh)						
	Residential	Commercial	Industrial	Public lighting	Total	Electricity generated	Total generate difference (excl. non-scheduled wind)
Base scenario							
2005	2078.2	890.9	7113.9	24.1	10107.1	10674.7	9982.4
2006	2113.0	883.0	7029.3	24.1	10049.3	10651.6	9892.7
2007	2152.5	959.6	7068.4	24.0	10204.6	10738.7	10122.7
2008	2112.3	966.1	7324.1	24.8	10427.3	11008.3	10259.9
2009	2067.7	1056.1	7270.3	25.4	10419.5	10964.2	10080.0
2010	2135.0	1090.5	7288.6	43.3	10557.3	10846.6	9920.0
2011	2085.6	1060.5	7199.9	36.9	10383.0	10912.9	9955.1
2012	2047.2	1055.8	6955.1	37.3	10095.4	10529.4	9595.8
2013	1921.3	1107.8	7043.9	36.1	10109.1	10518.8	9596.8
2014	1901.2	1122.1	6983.0	36.0	10042.4	10466.2	9102.5
2015	1904.7	1149.7	7119.1	37.1	10210.6	10641.5	9248.0
2016	1916.7	1171.1	7142.7	38.1	10268.6	10702.0	9308.5
2017	1926.0	1191.5	7265.1	39.3	10421.9	10861.7	9468.3
2018	1930.5	1212.6	7270.0	40.4	10453.5	10894.6	9501.2
2019	1933.5	1238.1	7278.6	41.5	10491.7	10934.5	9541.1
2020	1950.4	1266.8	7293.4	42.6	10553.3	10998.6	9605.2
2021	1970.0	1297.7	7310.1	43.7	10621.5	11069.8	9676.4
2022	1990.5	1329.0	7450.4	44.8	10814.8	11271.2	9877.8
2023	2009.8	1360.0	7467.5	46.0	10883.3	11342.6	9949.2
2024	2028.6	1391.4	7487.6	47.2	10954.8	11417.1	10023.6
2025	2044.7	1425.5	7505.7	48.5	11024.4	11489.7	10096.2
2026	2058.0	1458.0	7523.3	49.8	11089.0	11557.0	10163.6
2027	2070.5	1491.3	7541.3	51.1	11154.2	11624.9	10231.4
2028	2084.6	1526.9	7561.6	52.5	11225.6	11699.3	10305.9
2029	2102.7	1566.1	7584.1	53.9	11306.8	11784.0	10390.5
2030	2130.3	1609.9	7615.0	55.3	11410.5	11892.0	10498.6
2031	2160.8	1658.9	7645.4	56.8	11521.9	12008.1	10614.7
2032	2192.3	1707.0	7720.2	58.4	11677.8	12170.6	10777.2
2033	2224.6	1755.3	7751.8	59.9	11791.6	12289.3	10895.8
2034	2252.9	1800.9	7781.3	61.6	11896.6	12398.7	11005.3
2035	2276.1	1844.0	7808.2	63.2	11991.5	12497.5	11104.1
2036	2296.3	1887.6	7834.3	64.9	12083.1	12593.0	11199.6
2037	2315.5	1932.1	7860.4	66.7	12174.7	12688.5	11295.0
2038	2334.9	1977.9	7886.8	68.5	12268.1	12785.8	11392.4
2039	2354.5	2024.8	7913.9	70.3	12363.5	12885.3	11491.8
2040	2374.3	2072.8	7941.7	72.2	12461.0	12986.9	11593.4
2041	2394.2	2122.0	7970.2	74.2	12560.6	13090.7	11697.2
2042	2414.3	2172.3	7999.5	76.2	12662.4	13196.7	11803.3
2043	2434.6	2223.8	8029.6	78.3	12766.3	13305.1	11911.6
2044	2455.2	2276.6	8060.4	80.4	12872.5	13415.8	12022.3
2045	2476.0	2330.6	8091.9	82.6	12981.0	13528.9	12135.4

Table D.1	Electricity sales by class (GWh) – continued						
	Residential	Commercial	Industrial	Public lighting	Total	Electricity generated	Total generate difference (excl. non-scheduled wind)
High scenario							
2015	1924.3	1164.2	7391.1	37.5	10517.0	10960.9	10960.9
2016	1956.0	1200.8	7430.2	38.9	10625.9	11074.3	9680.9
2017	1987.4	1240.4	7715.4	40.5	10983.7	11447.2	10053.8
2018	2014.4	1282.3	7750.4	42.0	11089.1	11557.1	10163.6
2019	2040.2	1323.5	7783.0	43.6	11190.4	11662.6	10269.2
2020	2070.5	1368.4	7820.6	45.3	11304.8	11781.8	10388.4
2021	2105.2	1419.9	7864.1	47.1	11436.3	11918.9	10525.5
2022	2142.3	1475.6	8120.1	48.8	11786.8	12284.2	10890.8
2023	2178.1	1534.0	8255.4	50.6	12018.2	12525.4	11132.0
2024	2215.9	1581.6	8332.9	52.5	12182.8	12697.0	11303.5
2025	2256.9	1643.9	8380.2	54.8	12335.8	12856.4	11462.9
2026	2298.5	1710.0	8764.1	56.8	12829.4	13370.8	11977.4
2027	2330.9	1768.5	8810.8	58.9	12969.2	13516.5	12123.1
2028	2367.3	1822.9	9027.3	61.0	13278.5	13838.9	12445.5
2029	2386.9	1868.9	9067.4	62.9	13386.0	13950.9	12557.5
2030	2415.1	1930.2	9123.1	64.9	13533.2	14104.4	12710.9
2031	2450.8	1999.6	9180.1	67.0	13697.4	14275.5	12882.1
2032	2489.0	2083.3	9248.7	69.2	13890.1	14476.3	13082.9
2033	2528.6	2169.7	9318.9	71.6	14088.9	14683.5	13290.0
2034	2555.1	2222.2	9367.1	73.8	14218.1	14818.2	13424.7
2035	2571.6	2267.9	9411.5	75.9	14327.0	14931.6	13538.2
2036	2586.4	2320.0	9458.9	78.2	14443.6	15053.1	13659.7
2037	2601.6	2379.4	9511.0	80.5	14572.5	15187.5	13794.1
2038	2617.0	2441.7	9564.6	82.8	14706.1	15326.7	13933.3
2039	2631.9	2504.9	9619.5	85.3	14841.5	15467.9	14074.4
2040	2643.1	2558.0	9668.7	87.7	14957.5	15588.7	14195.3
2041	2656.4	2614.8	9720.1	90.3	15081.6	15718.0	14324.6
2042	2668.4	2670.7	9771.9	92.9	15203.8	15845.4	14452.0
2043	2683.5	2735.1	9828.9	95.7	15343.2	15990.7	14597.3
2044	2704.6	2815.9	9895.8	98.8	15515.1	16169.9	14776.4
2045	2726.4	2887.1	9952.1	102.9	15668.5	16329.8	14936.3

Table D.1	Electricity sales by class (GWh) – continued						
	Residential	Commercial	Industrial	Public lighting	Total	Electricity generated	Total generate difference (excl. non-scheduled wind)
Low scenario							
2015	1896.9	1134.8	6806.1	36.7	9874.5	10291.2	8897.8
2016	1900.3	1141.5	6807.7	37.4	9886.9	10304.1	8910.7
2017	1904.3	1150.7	6780.2	38.1	9873.4	10290.0	8896.6
2018	1903.9	1160.7	6763.8	38.8	9867.4	10283.8	8890.4
2019	1902.1	1170.2	6745.1	39.6	9857.0	10272.9	8879.5
2020	1906.1	1184.1	6335.3	40.3	9465.8	9865.3	8471.8
2021	1911.2	1198.5	5966.8	41.1	9117.6	9502.3	8108.9
2022	1919.3	1215.4	5961.3	41.9	9137.9	9523.5	8130.1
2023	1930.0	1236.8	5960.2	42.8	9169.9	9556.8	8163.4
2024	1940.6	1255.1	5953.7	44.2	9193.6	9581.6	8188.2
2025	1950.3	1274.9	5944.1	45.5	9214.7	9603.6	8210.2
2026	1957.4	1292.8	5933.6	46.9	9230.7	9620.3	8226.9
2027	1963.4	1311.1	5923.4	48.3	9246.2	9636.4	8243.0
2028	1970.8	1331.0	5914.7	49.8	9266.3	9657.4	8263.9
2029	1981.9	1353.6	5907.3	51.3	9294.2	9686.4	8293.0
2030	1997.3	1379.2	5906.1	52.9	9335.5	9729.5	8336.0
2031	2015.2	1408.7	5902.5	54.5	9380.9	9776.7	8383.3
2032	2033.6	1436.8	5899.2	56.2	9425.9	9823.7	8430.3
2033	2052.6	1464.6	5895.3	57.9	9470.4	9870.1	8476.7
2034	2068.0	1489.7	5889.2	59.7	9506.6	9907.8	8514.4
2035	2078.6	1512.3	5881.4	61.5	9533.8	9936.1	8542.7
2036	2085.7	1534.9	5872.7	63.4	9556.7	9960.1	8566.6
2037	2091.4	1557.8	5863.8	65.4	9578.5	9982.7	8589.3
2038	2097.2	1581.3	5854.7	67.4	9600.5	10005.7	8612.3
2039	2103.0	1605.3	5845.5	69.4	9623.2	10029.3	8635.9
2040	2109.0	1629.6	5836.3	71.5	9646.4	10053.5	8660.1
2041	2115.0	1654.4	5827.1	73.7	9670.3	10078.4	8685.0
2042	2121.1	1679.7	5818.1	76.0	9694.8	10103.9	8710.5
2043	2127.1	1705.4	5809.0	78.3	9719.8	10130.0	8736.6
2044	2133.5	1731.5	5799.9	80.7	9745.7	10157.0	8763.6
2045	2119.0	1741.5	5785.9	81.9	9728.3	10138.8	8745.4

Table D.2	Maximum demands (including non-scheduled generation) – WINTER (these are calendar years for winter)		
	10th	50th	90th
Base scenario			
2005	1802.6	1802.6	1802.6
2006	1716.1	1716.1	1716.1
2007	1802.5	1802.5	1802.5
2008	1861.0	1861.0	1861.0
2009	1752.6	1752.6	1752.6
2010	1769.2	1769.2	1769.2
2011	1794.8	1794.8	1794.8
2012	1662.4	1662.4	1662.4
2013	1703.1	1703.1	1703.1
2014	1689.5	1689.5	1689.5
2015	1707.6	1687.4	1671.0
2016	1742.9	1722.7	1706.3
2017	1753.1	1732.9	1716.5
2018	1764.6	1744.5	1728.1
2019	1781.3	1761.1	1744.8
2020	1799.7	1779.5	1763.2
2021	1832.5	1812.4	1796.1
2022	1849.6	1829.4	1813.2
2023	1867.2	1847.1	1830.8
2024	1884.6	1864.5	1848.3
2025	1901.0	1880.9	1864.7
2026	1917.6	1897.5	1881.4
2027	1934.1	1914.0	1897.8
2028	1952.5	1932.5	1916.3
2029	1975.6	1955.6	1939.5
2030	2000.5	1980.5	1964.4
2031	2030.9	2010.9	1994.9
2032	2055.8	2035.8	2019.8
2033	2079.1	2059.1	2043.2
2034	2100.6	2080.6	2064.7
2035	2121.3	2101.4	2085.5
2036	2142.5	2122.5	2106.7
2037	2163.7	2143.8	2127.9
2038	2185.3	2165.4	2149.6
2039	2207.5	2187.6	2171.8
2040	2230.4	2210.5	2194.8
2041	2253.6	2233.8	2218.0
2042	2277.6	2257.7	2242.1
2043	2301.9	2282.1	2266.4
2044	2327.0	2307.1	2291.5

Table D.2	Maximum demands (including non-scheduled generation) – WINTER (these are calendar years for winter) – continued		
	10th	50th	90th
High scenario			
2015	1750.2	1730.0	1713.6
2016	1817.7	1797.6	1781.2
2017	1843.9	1823.8	1807.5
2018	1869.3	1849.2	1832.9
2019	1900.8	1880.7	1864.5
2020	1936.4	1916.3	1900.1
2021	1995.4	1975.3	1959.2
2022	2039.5	2019.5	2003.4
2023	2074.1	2054.1	2038.0
2024	2109.5	2089.6	2073.6
2025	2189.5	2169.5	2153.6
2026	2222.5	2202.6	2186.7
2027	2277.7	2257.8	2242.0
2028	2305.1	2285.2	2269.4
2029	2337.6	2317.7	2302.0
2030	2373.8	2353.9	2338.2
2031	2415.6	2395.7	2380.1
2032	2458.1	2438.3	2422.7
2033	2486.9	2467.1	2451.6
2034	2511.8	2492.1	2476.5
2035	2538.2	2518.5	2503.0
2036	2567.6	2547.9	2532.4
2037	2597.6	2577.9	2562.5
2038	2627.9	2608.3	2592.9
2039	2654.5	2634.9	2619.6
2040	2683.2	2663.6	2648.3
2041	2711.3	2691.7	2676.5
2042	2743.2	2723.6	2708.5
2043	2781.6	2762.1	2747.0
2044	2816.7	2797.1	2782.0

Table D.2	Maximum demands (including non-scheduled generation) – WINTER (these are calendar years for winter) – continued		
	10th	50th	90th
Low scenario			
2015	1659.6	1639.3	1622.9
2016	1669.3	1649.1	1632.7
2017	1671.2	1651.0	1634.6
2018	1672.2	1652.0	1635.6
2019	1627.7	1607.5	1591.1
2020	1588.8	1568.6	1552.2
2021	1595.2	1575.0	1558.6
2022	1588.7	1568.5	1552.0
2023	1595.8	1575.6	1559.2
2024	1602.5	1582.3	1565.9
2025	1608.1	1587.9	1571.5
2026	1613.5	1593.4	1577.0
2027	1618.8	1598.6	1582.2
2028	1625.7	1605.5	1589.1
2029	1635.3	1615.2	1598.8
2030	1645.8	1625.6	1609.3
2031	1656.2	1636.1	1619.7
2032	1666.8	1646.6	1630.3
2033	1675.8	1655.6	1639.3
2034	1682.9	1662.8	1646.5
2035	1689.3	1669.1	1652.8
2036	1695.4	1675.3	1659.0
2037	1701.7	1681.5	1665.2
2038	1708.1	1687.9	1671.7
2039	1714.6	1694.5	1678.2
2040	1721.3	1701.2	1685.0
2041	1728.2	1708.1	1691.8
2042	1735.2	1715.1	1698.9
2043	1742.5	1722.3	1706.1
2044	1741.0	1720.8	1704.6

Table D.3	Maximum demands (including non-scheduled generation) – SUMMER		
	10th	50th	90th
Base scenario			
2005	1366.6	1366.6	1366.6
2006	1315.4	1315.4	1315.4
2007	1393.4	1393.4	1393.4
2008	1425.1	1425.1	1425.1
2009	1475.3	1475.3	1475.3
2010	1403.8	1403.8	1403.8
2011	1445.5	1445.5	1445.5
2012	1408.8	1408.8	1408.8
2013	1331.6	1331.6	1331.6
2014	1366.8	1366.8	1366.8
2015	1394.1	1370.0	1351.2
2016	1416.5	1392.1	1373.1
2017	1454.3	1429.6	1410.3
2018	1463.7	1438.8	1419.4
2019	1474.2	1449.0	1429.4
2020	1488.3	1462.8	1442.9
2021	1503.8	1477.9	1457.8
2022	1534.7	1508.4	1488.0
2023	1550.3	1523.7	1502.9
2024	1566.3	1539.3	1518.3
2025	1582.2	1554.8	1533.5
2026	1597.3	1569.6	1548.0
2027	1612.7	1584.6	1562.7
2028	1629.2	1600.7	1578.5
2029	1647.3	1618.3	1595.9
2030	1669.0	1639.5	1616.6
2031	1692.0	1662.0	1638.7
2032	1720.5	1689.9	1666.1
2033	1743.6	1712.4	1688.2
2034	1765.4	1733.7	1709.1
2035	1785.9	1753.6	1728.6
2036	1805.7	1773.0	1747.6
2037	1826.0	1792.7	1767.0
2038	1846.2	1812.5	1786.4
2039	1866.8	1832.5	1806.1
2040	1887.7	1853.0	1826.1
2041	1909.3	1874.0	1846.8
2042	1931.1	1895.3	1867.6
2043	1953.6	1917.2	1889.1
2044	1976.2	1939.3	1910.8
2045	1999.5	1962.0	1933.1

Table D.3	Maximum demands (including non-scheduled generation) – SUMMER – continued		
	10th	50th	90th
High scenario			
2015	1435.6	1411.3	1392.3
2016	1467.0	1442.1	1422.7
2017	1533.4	1507.9	1488.0
2018	1555.6	1529.5	1509.2
2019	1577.0	1550.5	1529.8
2020	1603.6	1576.5	1555.3
2021	1633.2	1605.4	1583.8
2022	1687.3	1658.8	1636.6
2023	1726.7	1697.4	1674.7
2024	1757.6	1727.6	1704.4
2025	1788.1	1757.4	1733.6
2026	1861.7	1830.1	1805.7
2027	1890.7	1858.4	1833.4
2028	1943.7	1910.7	1885.1
2029	1971.0	1937.4	1911.4
2030	2001.6	1967.3	1940.7
2031	2035.2	2000.0	1972.9
2032	2073.1	2037.0	2009.1
2033	2111.7	2074.6	2046.0
2034	2139.7	2101.9	2072.8
2035	2164.8	2126.4	2096.8
2036	2191.0	2152.0	2121.9
2037	2219.5	2179.9	2149.3
2038	2248.6	2208.2	2177.1
2039	2277.9	2236.8	2205.2
2040	2304.4	2262.6	2230.5
2041	2332.5	2290.0	2257.4
2042	2360.2	2317.0	2283.9
2043	2390.8	2347.0	2313.3
2044	2426.5	2381.8	2347.4
2045	2459.7	2414.1	2379.1

Table D.3	Maximum demands (including non-scheduled generation) – SUMMER – continued		
	10th	50th	90th
Low scenario			
2014	1346.1	1322.2	1303.6
2015	1359.8	1335.9	1317.2
2016	1373.3	1349.3	1330.5
2017	1375.3	1351.2	1332.4
2018	1376.5	1352.4	1333.6
2019	1332.5	1308.4	1289.6
2020	1293.7	1269.5	1250.7
2021	1299.6	1275.3	1256.3
2022	1292.7	1268.2	1249.1
2023	1299.1	1274.5	1255.3
2024	1305.2	1280.4	1261.1
2025	1310.4	1285.5	1266.1
2026	1315.6	1290.6	1271.1
2027	1321.5	1296.3	1276.7
2028	1328.6	1303.3	1283.6
2029	1337.9	1312.3	1292.4
2030	1347.8	1322.0	1301.9
2031	1357.6	1331.6	1311.3
2032	1367.4	1341.2	1320.7
2033	1376.0	1349.5	1328.8
2034	1383.1	1356.5	1335.7
2035	1389.6	1362.8	1341.9
2036	1395.9	1369.0	1348.0
2037	1402.3	1375.2	1354.1
2038	1408.8	1381.5	1360.3
2039	1415.4	1388.0	1366.6
2040	1422.1	1394.5	1373.0
2041	1428.9	1401.2	1379.6
2042	1435.8	1407.9	1386.2
2043	1442.9	1414.8	1392.9
2044	1443.2	1415.1	1393.3
2045	1346.1	1322.2	1303.6

Table D.4	Maximum demands (excluding embedded generation)					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
Base scenario						
2005	1728.6	1728.6	1728.6	1356.0	1356.0	1356.0
2006	1636.5	1636.5	1636.5	1295.5	1295.5	1295.5
2007	1710.8	1710.8	1710.8	1370.6	1370.6	1370.6
2008	1773.8	1773.8	1773.8	1399.4	1399.4	1399.4
2009	1690.8	1690.8	1690.8	1434.2	1434.2	1434.2
2010	1698.6	1698.6	1698.6	1377.8	1377.8	1377.8
2011	1717.1	1717.1	1717.1	1382.5	1382.5	1382.5
2012	1574.5	1574.5	1574.5	1348.4	1348.4	1348.4
2013	1659.2	1659.2	1659.2	1292.0	1292.0	1292.0
2014	1601.3	1601.3	1601.3	1344.8	1344.8	1344.8
2015	1641.8	1621.6	1605.2	1356.6	1332.5	1313.7
2016	1677.1	1656.9	1640.5	1379.0	1354.6	1335.6
2017	1687.3	1667.1	1650.7	1416.8	1392.1	1372.8
2018	1698.8	1678.7	1662.3	1426.2	1401.3	1381.9
2019	1715.5	1695.3	1679.0	1436.7	1411.5	1391.9
2020	1733.9	1713.7	1697.4	1450.8	1425.3	1405.4
2021	1766.7	1746.6	1730.3	1466.3	1440.4	1420.3
2022	1783.8	1763.6	1747.4	1497.2	1470.9	1450.5
2023	1801.4	1781.3	1765.0	1512.8	1486.2	1465.4
2024	1818.8	1798.7	1782.5	1528.8	1501.8	1480.8
2025	1835.2	1815.1	1798.9	1544.7	1517.3	1496.0
2026	1851.8	1831.7	1815.6	1559.8	1532.1	1510.5
2027	1868.3	1848.2	1832.0	1575.2	1547.1	1525.2
2028	1886.7	1866.7	1850.5	1591.7	1563.2	1541.0
2029	1909.8	1889.8	1873.7	1609.8	1580.8	1558.4
2030	1934.7	1914.7	1898.6	1631.5	1602.0	1579.1
2031	1965.1	1945.1	1929.1	1654.5	1624.5	1601.2
2032	1990.0	1970.0	1954.0	1683.0	1652.4	1628.6
2033	2013.3	1993.3	1977.4	1706.1	1674.9	1650.7
2034	2034.8	2014.8	1998.9	1727.9	1696.2	1671.6
2035	2055.5	2035.6	2019.7	1748.4	1716.1	1691.1
2036	2076.7	2056.7	2040.9	1768.2	1735.5	1710.1
2037	2097.9	2078.0	2062.1	1788.5	1755.2	1729.5
2038	2119.5	2099.6	2083.8	1808.7	1775.0	1748.9
2039	2141.7	2121.8	2106.0	1829.3	1795.0	1768.6
2040	2164.6	2144.7	2129.0	1850.2	1815.5	1788.6
2041	2187.8	2168.0	2152.2	1871.8	1836.5	1809.3
2042	2211.8	2191.9	2176.3	1893.6	1857.8	1830.1
2043	2236.1	2216.3	2200.6	1916.1	1879.7	1851.6
2044	2261.2	2241.3	2225.7	1938.7	1901.8	1873.3
2045				1962.0	1924.5	1895.6

Table D.4	Maximum demands (excluding embedded generation) – continued					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
High scenario						
2015	1684.4	1664.2	1647.8	1398.1	1373.8	1354.8
2016	1751.9	1731.8	1715.4	1429.5	1404.6	1385.2
2017	1778.1	1758.0	1741.7	1495.9	1470.4	1450.5
2018	1803.5	1783.4	1767.1	1518.1	1492.0	1471.7
2019	1835.0	1814.9	1798.7	1539.5	1513.0	1492.3
2020	1870.6	1850.5	1834.3	1566.1	1539.0	1517.8
2021	1929.6	1909.5	1893.4	1595.7	1567.9	1546.3
2022	1973.7	1953.7	1937.6	1649.8	1621.3	1599.1
2023	2008.3	1988.3	1972.2	1689.2	1659.9	1637.2
2024	2043.7	2023.8	2007.8	1720.1	1690.1	1666.9
2025	2123.7	2103.7	2087.8	1750.6	1719.9	1696.1
2026	2156.7	2136.8	2120.9	1824.2	1792.6	1768.2
2027	2211.9	2192.0	2176.2	1853.2	1820.9	1795.9
2028	2239.3	2219.4	2203.6	1906.2	1873.2	1847.6
2029	2271.8	2251.9	2236.2	1933.5	1899.9	1873.9
2030	2308.0	2288.1	2272.4	1964.1	1929.8	1903.2
2031	2349.8	2329.9	2314.3	1997.7	1962.5	1935.4
2032	2392.3	2372.5	2356.9	2035.6	1999.5	1971.6
2033	2421.1	2401.3	2385.8	2074.2	2037.1	2008.5
2034	2446.0	2426.3	2410.7	2102.2	2064.4	2035.3
2035	2472.4	2452.7	2437.2	2127.3	2088.9	2059.3
2036	2501.8	2482.1	2466.6	2153.5	2114.5	2084.4
2037	2531.8	2512.1	2496.7	2182.0	2142.4	2111.8
2038	2562.1	2542.5	2527.1	2211.1	2170.7	2139.6
2039	2588.7	2569.1	2553.8	2240.4	2199.3	2167.7
2040	2617.4	2597.8	2582.5	2266.9	2225.1	2193.0
2041	2645.5	2625.9	2610.7	2295.0	2252.5	2219.9
2042	2677.4	2657.8	2642.7	2322.7	2279.5	2246.4
2043	2715.8	2696.3	2681.2	2353.3	2309.5	2275.8
2044	2750.9	2731.3	2716.2	2389.0	2344.3	2309.9
2045				2422.2	2376.6	2341.6

Table D.4	Maximum demands (excluding embedded generation) – continued					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
Low scenario						
2015	1593.8	1573.5	1557.1	1308.6	1284.7	1266.1
2016	1603.5	1583.3	1566.9	1322.3	1298.4	1279.7
2017	1605.4	1585.2	1568.8	1335.8	1311.8	1293.0
2018	1606.4	1586.2	1569.8	1337.8	1313.7	1294.9
2019	1561.9	1541.7	1525.3	1339.0	1314.9	1296.1
2020	1523.0	1502.8	1486.4	1295.0	1270.9	1252.1
2021	1529.4	1509.2	1492.8	1256.2	1232.0	1213.2
2022	1522.9	1502.7	1486.2	1262.1	1237.8	1218.8
2023	1530.0	1509.8	1493.4	1255.2	1230.7	1211.6
2024	1536.7	1516.5	1500.1	1261.6	1237.0	1217.8
2025	1542.3	1522.1	1505.7	1267.7	1242.9	1223.6
2026	1547.7	1527.6	1511.2	1272.9	1248.0	1228.6
2027	1553.0	1532.8	1516.4	1278.1	1253.1	1233.6
2028	1559.9	1539.7	1523.3	1284.0	1258.8	1239.2
2029	1569.5	1549.4	1533.0	1291.1	1265.8	1246.1
2030	1580.0	1559.8	1543.5	1300.4	1274.8	1254.9
2031	1590.4	1570.3	1553.9	1310.3	1284.5	1264.4
2032	1601.0	1580.8	1564.5	1320.1	1294.1	1273.8
2033	1610.0	1589.8	1573.5	1329.9	1303.7	1283.2
2034	1617.1	1597.0	1580.7	1338.5	1312.0	1291.3
2035	1623.5	1603.3	1587.0	1345.6	1319.0	1298.2
2036	1629.6	1609.5	1593.2	1352.1	1325.3	1304.4
2037	1635.9	1615.7	1599.4	1358.4	1331.5	1310.5
2038	1642.3	1622.1	1605.9	1364.8	1337.7	1316.6
2039	1648.8	1628.7	1612.4	1371.3	1344.0	1322.8
2040	1655.5	1635.4	1619.2	1377.9	1350.5	1329.1
2041	1662.4	1642.3	1626.0	1384.6	1357.0	1335.5
2042	1669.4	1649.3	1633.1	1391.4	1363.7	1342.1
2043	1676.7	1656.5	1640.3	1398.3	1370.4	1348.7
2044	1675.2	1655.0	1638.8	1405.4	1377.3	1355.4
2045				1405.7	1377.6	1355.8

Table D.5	Maximum demands (excluding wind and embedded generation)					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
Base scenario						
2005	1670.6	1670.6	1670.6	1297.2	1297.2	1297.2
2006	1619.9	1619.9	1619.9	1292.2	1292.2	1292.2
2007	1695.7	1695.7	1695.7	1365.1	1365.1	1365.1
2008	1662.7	1662.7	1662.7	1331.2	1331.2	1331.2
2009	1669.3	1669.3	1669.3	1434.2	1434.2	1434.2
2010	1669.3	1669.3	1669.3	1359.3	1359.3	1359.3
2011	1620.3	1620.3	1620.3	1286.7	1286.7	1286.7
2012	1573.8	1573.8	1573.8	1329.9	1329.9	1329.9
2013	1582.2	1582.2	1582.2	1236.4	1236.4	1236.4
2014	1557.1	1557.1	1557.1	1267.3	1267.3	1267.3
2015	1596.8	1576.6	1560.2	1212.4	1188.3	1169.5
2016	1632.1	1611.9	1595.5	1234.8	1210.4	1191.4
2017	1642.3	1622.1	1605.7	1272.6	1247.9	1228.6
2018	1653.8	1633.7	1617.3	1282.0	1257.1	1237.7
2019	1670.5	1650.3	1634.0	1292.5	1267.3	1247.7
2020	1688.9	1668.7	1652.4	1306.6	1281.1	1261.2
2021	1721.7	1701.6	1685.3	1322.1	1296.2	1276.1
2022	1738.8	1718.6	1702.4	1353.0	1326.7	1306.3
2023	1756.4	1736.3	1720.0	1368.6	1342.0	1321.2
2024	1773.8	1753.7	1737.5	1384.6	1357.6	1336.6
2025	1790.2	1770.1	1753.9	1400.5	1373.1	1351.8
2026	1806.8	1786.7	1770.6	1415.6	1387.9	1366.3
2027	1823.3	1803.2	1787.0	1431.0	1402.9	1381.0
2028	1841.7	1821.7	1805.5	1447.5	1419.0	1396.8
2029	1864.8	1844.8	1828.7	1465.6	1436.6	1414.2
2030	1889.7	1869.7	1853.6	1487.3	1457.8	1434.9
2031	1920.1	1900.1	1884.1	1510.3	1480.3	1457.0
2032	1945.0	1925.0	1909.0	1538.8	1508.2	1484.4
2033	1968.3	1948.3	1932.4	1561.9	1530.7	1506.5
2034	1989.8	1969.8	1953.9	1583.7	1552.0	1527.4
2035	2010.5	1990.6	1974.7	1604.2	1571.9	1546.9
2036	2031.7	2011.7	1995.9	1624.0	1591.3	1565.9
2037	2052.9	2033.0	2017.1	1644.3	1611.0	1585.3
2038	2074.5	2054.6	2038.8	1664.5	1630.8	1604.7
2039	2096.7	2076.8	2061.0	1685.1	1650.8	1624.4
2040	2119.6	2099.7	2084.0	1706.0	1671.3	1644.4
2041	2142.8	2123.0	2107.2	1727.6	1692.3	1665.1
2042	2166.8	2146.9	2131.3	1749.4	1713.6	1685.9
2043	2191.1	2171.3	2155.6	1771.9	1735.5	1707.4
2044	2216.2	2196.3	2180.7	1794.5	1757.6	1729.1
2045				1817.8	1780.3	1751.4

Table D.5	Maximum demands (excluding wind and embedded generation) – continued					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
High scenario						
2015	1639.4	1619.2	1602.8	1253.9	1229.6	1210.6
2016	1706.9	1686.8	1670.4	1285.3	1260.4	1241.0
2017	1733.1	1713.0	1696.7	1351.7	1326.2	1306.3
2018	1758.5	1738.4	1722.1	1373.9	1347.8	1327.5
2019	1790.0	1769.9	1753.7	1395.3	1368.8	1348.1
2020	1825.6	1805.5	1789.3	1421.9	1394.8	1373.6
2021	1884.6	1864.5	1848.4	1451.5	1423.7	1402.1
2022	1928.7	1908.7	1892.6	1505.6	1477.1	1454.9
2023	1963.3	1943.3	1927.2	1545.0	1515.7	1493.0
2024	1998.7	1978.8	1962.8	1575.9	1545.9	1522.7
2025	2078.7	2058.7	2042.8	1606.4	1575.7	1551.9
2026	2111.7	2091.8	2075.9	1680.0	1648.4	1624.0
2027	2166.9	2147.0	2131.2	1709.0	1676.7	1651.7
2028	2194.3	2174.4	2158.6	1762.0	1729.0	1703.4
2029	2226.8	2206.9	2191.2	1789.3	1755.7	1729.7
2030	2263.0	2243.1	2227.4	1819.9	1785.6	1759.0
2031	2304.8	2284.9	2269.3	1853.5	1818.3	1791.2
2032	2347.3	2327.5	2311.9	1891.4	1855.3	1827.4
2033	2376.1	2356.3	2340.8	1930.0	1892.9	1864.3
2034	2401.0	2381.3	2365.7	1958.0	1920.2	1891.1
2035	2427.4	2407.7	2392.2	1983.1	1944.7	1915.1
2036	2456.8	2437.1	2421.6	2009.3	1970.3	1940.2
2037	2486.8	2467.1	2451.7	2037.8	1998.2	1967.6
2038	2517.1	2497.5	2482.1	2066.9	2026.5	1995.4
2039	2543.7	2524.1	2508.8	2096.2	2055.1	2023.5
2040	2572.4	2552.8	2537.5	2122.7	2080.9	2048.8
2041	2600.5	2580.9	2565.7	2150.8	2108.3	2075.7
2042	2632.4	2612.8	2597.7	2178.5	2135.3	2102.2
2043	2670.8	2651.3	2636.2	2209.1	2165.3	2131.6
2044	2705.9	2686.3	2671.2	2244.8	2200.1	2165.7
2045				2278.0	2232.4	2197.4

Table D.5	Maximum demands (excluding wind and embedded generation) – continued					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
Low scenario						
2015	1548.8	1528.5	1512.1	1164.4	1140.5	1121.9
2016	1558.5	1538.3	1521.9	1178.1	1154.2	1135.5
2017	1560.4	1540.2	1523.8	1191.6	1167.6	1148.8
2018	1561.4	1541.2	1524.8	1193.6	1169.5	1150.7
2019	1516.9	1496.7	1480.3	1194.8	1170.7	1151.9
2020	1478.0	1457.8	1441.4	1150.8	1126.7	1107.9
2021	1484.4	1464.2	1447.8	1112.0	1087.8	1069.0
2022	1477.9	1457.7	1441.2	1117.9	1093.6	1074.6
2023	1485.0	1464.8	1448.4	1111.0	1086.5	1067.4
2024	1491.7	1471.5	1455.1	1117.4	1092.8	1073.6
2025	1497.3	1477.1	1460.7	1123.5	1098.7	1079.4
2026	1502.7	1482.6	1466.2	1128.7	1103.8	1084.4
2027	1508.0	1487.8	1471.4	1133.9	1108.9	1089.4
2028	1514.9	1494.7	1478.3	1139.8	1114.6	1095.0
2029	1524.5	1504.4	1488.0	1146.9	1121.6	1101.9
2030	1535.0	1514.8	1498.5	1156.2	1130.6	1110.7
2031	1545.4	1525.3	1508.9	1166.1	1140.3	1120.2
2032	1556.0	1535.8	1519.5	1175.9	1149.9	1129.6
2033	1565.0	1544.8	1528.5	1185.7	1159.5	1139.0
2034	1572.1	1552.0	1535.7	1194.3	1167.8	1147.1
2035	1578.5	1558.3	1542.0	1201.4	1174.8	1154.0
2036	1584.6	1564.5	1548.2	1207.9	1181.1	1160.2
2037	1590.9	1570.7	1554.4	1214.2	1187.3	1166.3
2038	1597.3	1577.1	1560.9	1220.6	1193.5	1172.4
2039	1603.8	1583.7	1567.4	1227.1	1199.8	1178.6
2040	1610.5	1590.4	1574.2	1233.7	1206.3	1184.9
2041	1617.4	1597.3	1581.0	1240.4	1212.8	1191.3
2042	1624.4	1604.3	1588.1	1247.2	1219.5	1197.9
2043	1631.7	1611.5	1595.3	1254.1	1226.2	1204.5
2044	1630.2	1610.0	1593.8	1261.2	1233.1	1211.2
2045				1261.5	1233.4	1211.6

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Table D.7	Retail sales by class (GWh)				
	Residential	Commercial (estimate)	Industrial	Public lighting	Total
Base scenario					
2005	2078.2	890.9	2080.9	24.1	5074.1
2006	2113.0	883.0	2015.1	24.1	5035.2
2007	2152.5	959.6	1904.5	24.0	5040.6
2008	2112.3	966.1	2031.7	24.8	5134.9
2009	2067.7	1056.1	2074.9	25.4	5224.1
2010	2135.0	1090.5	2025.4	43.3	5294.2
2011	2085.6	1060.5	1626.2	36.9	4809.2
2012	2047.2	1055.8	1625.3	37.3	4765.6
2013	1921.3	1107.8	1596.4	36.1	4661.6
2014	1901.2	1122.1	1597.5	36.0	4656.8
2015	1904.7	1149.7	1614.4	37.1	4705.9
2016	1916.7	1171.1	1638.0	38.1	4763.9
2017	1926.0	1191.5	1657.1	39.3	4813.9
2018	1930.5	1212.6	1662.0	40.4	4845.5
2019	1933.5	1238.1	1670.7	41.5	4883.8
2020	1950.4	1266.8	1685.5	42.6	4945.3
2021	1970.0	1297.7	1702.1	43.7	5013.5
2022	1990.5	1329.0	1720.1	44.8	5084.4
2023	2009.8	1360.0	1737.3	46.0	5153.1
2024	2028.6	1391.4	1757.3	47.2	5224.5
2025	2044.7	1425.5	1775.5	48.5	5294.2
2026	2058.0	1458.0	1793.0	49.8	5358.8
2027	2070.5	1491.3	1811.0	51.1	5423.9
2028	2084.6	1526.9	1831.4	52.5	5495.4
2029	2102.7	1566.1	1853.9	53.9	5576.6
2030	2130.3	1609.9	1884.8	55.3	5680.3
2031	2160.8	1658.9	1915.1	56.8	5791.6
2032	2192.3	1707.0	1946.9	58.4	5904.6
2033	2224.6	1755.3	1978.6	59.9	6018.4
2034	2252.9	1800.9	2008.0	61.6	6123.4
2035	2276.1	1844.0	2034.9	63.2	6218.2
2036	2296.3	1887.6	2061.0	64.9	6309.8
2037	2315.5	1932.1	2087.1	66.7	6401.4
2038	2334.9	1977.9	2113.5	68.5	6494.8
2039	2354.5	2024.8	2140.6	70.3	6590.2
2040	2374.3	2072.8	2168.4	72.2	6687.7
2041	2394.2	2122.0	2197.0	74.2	6787.4
2042	2414.3	2172.3	2226.3	76.2	6889.1
2043	2434.6	2223.8	2256.3	78.3	6993.0
2044	2455.2	2276.6	2287.1	80.4	7099.3
2045	2476.0	2330.6	2318.6	82.6	7207.8

Table D.7	Retail sales by class (GWh) – continued				
	Residential	Commercial (estimate)	Industrial	Public lighting	Total
High scenario					
2015	1924.3	1164.2	1630.9	37.5	4756.9
2016	1956.0	1200.8	1670.0	38.9	4865.7
2017	1987.4	1240.4	1711.0	40.5	4979.3
2018	2014.4	1282.3	1746.1	42.0	5084.8
2019	2040.2	1323.5	1778.7	43.6	5186.0
2020	2070.5	1368.4	1816.3	45.3	5300.5
2021	2105.2	1419.9	1859.8	47.1	5432.0
2022	2142.3	1475.6	1907.5	48.8	5574.2
2023	2178.1	1534.0	1956.9	50.6	5719.6
2024	2215.9	1581.6	2000.1	52.5	5850.1
2025	2256.9	1643.9	2047.4	54.8	6003.0
2026	2298.5	1710.0	2100.3	56.8	6165.6
2027	2330.9	1768.5	2147.0	58.9	6305.3
2028	2367.3	1822.9	2191.4	61.0	6442.6
2029	2386.9	1868.9	2231.5	62.9	6550.2
2030	2415.1	1930.2	2287.3	64.9	6697.5
2031	2450.8	1999.6	2344.2	67.0	6861.6
2032	2489.0	2083.3	2412.9	69.2	7054.4
2033	2528.6	2169.7	2483.1	71.6	7253.0
2034	2555.1	2222.2	2531.2	73.8	7382.3
2035	2571.6	2267.9	2575.7	75.9	7491.1
2036	2586.4	2320.0	2623.1	78.2	7607.7
2037	2601.6	2379.4	2675.1	80.5	7736.6
2038	2617.0	2441.7	2728.8	82.8	7870.3
2039	2631.9	2504.9	2783.7	85.3	8005.8
2040	2643.1	2558.0	2832.8	87.7	8121.6
2041	2656.4	2614.8	2884.3	90.3	8245.8
2042	2668.4	2670.7	2936.0	92.9	8368.0
2043	2683.5	2735.1	2993.0	95.7	8507.3
2044	2704.6	2815.9	3060.0	98.8	8679.3
2045	2726.4	2887.1	3116.3	102.9	8832.7

Table D.7	Retail sales by class (GWh) – continued				
	Residential	Commercial (estimate)	Industrial	Public lighting	Total
Low scenario					
2015	1896.9	1134.8	1592.8	36.7	4661.2
2016	1900.3	1141.5	1594.3	37.4	4673.5
2017	1904.3	1150.7	1597.0	38.1	4690.1
2018	1903.9	1160.7	1580.6	38.8	4684.0
2019	1902.1	1170.2	1561.9	39.6	4673.8
2020	1906.1	1184.1	1550.7	40.3	4681.2
2021	1911.2	1198.5	1540.9	41.1	4691.7
2022	1919.3	1215.4	1535.4	41.9	4712.0
2023	1930.0	1236.8	1534.3	42.8	4743.9
2024	1940.6	1255.1	1527.8	44.2	4767.7
2025	1950.3	1274.9	1518.2	45.5	4788.9
2026	1957.4	1292.8	1507.7	46.9	4804.8
2027	1963.4	1311.1	1497.5	48.3	4820.3
2028	1970.8	1331.0	1488.8	49.8	4840.4
2029	1981.9	1353.6	1481.4	51.3	4868.2
2030	1997.3	1379.2	1480.2	52.9	4909.6
2031	2015.2	1408.7	1476.6	54.5	4955.0
2032	2033.6	1436.8	1473.3	56.2	4999.9
2033	2052.6	1464.6	1469.4	57.9	5044.5
2034	2068.0	1489.7	1463.3	59.7	5080.7
2035	2078.6	1512.3	1455.5	61.5	5107.9
2036	2085.7	1534.9	1446.8	63.4	5130.8
2037	2091.4	1557.8	1437.9	65.4	5152.5
2038	2097.2	1581.3	1428.8	67.4	5174.7
2039	2103.0	1605.3	1419.6	69.4	5197.3
2040	2109.0	1629.6	1410.4	71.5	5220.5
2041	2115.0	1654.4	1401.2	73.7	5244.3
2042	2121.1	1679.7	1392.2	76.0	5269.0
2043	2127.1	1705.4	1383.1	78.3	5293.9
2044	2133.5	1731.5	1374.0	80.7	5319.7
2045	2119.0	1741.5	1360.0	81.9	5302.4

Table D.8	Retail energy maximum demands					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
Base scenario						
2005	1186.0	1186.0	1186.0	776.1	776.1	776.1
2006	1108.6	1108.6	1108.6	738.5	738.5	738.5
2007	1198.2	1198.2	1198.2	773.4	773.4	773.4
2008	1125.1	1125.1	1125.1	746.3	746.3	746.3
2009	1078.8	1078.8	1078.8	759.6	759.6	759.6
2010	1050.6	1050.6	1050.6	684.1	684.1	684.1
2011	1054.5	1054.5	1054.5	745.0	745.0	745.0
2012	1034.8	1034.8	1034.8	679.8	679.8	679.8
2013	975.6	975.6	975.6	623.9	623.9	623.9
2014	956.5	956.5	956.5	644.7	644.7	644.7
2015	999.7	979.5	963.1	690.0	665.9	647.1
2016	1021.8	1001.6	985.2	712.2	687.8	668.8
2017	1031.8	1011.6	995.3	737.0	712.3	693.0
2018	1043.3	1023.1	1006.8	746.3	721.4	701.9
2019	1059.9	1039.7	1023.4	756.6	731.5	711.9
2020	1077.9	1057.8	1041.5	770.7	745.2	725.3
2021	1096.2	1076.0	1059.7	785.8	760.0	739.8
2022	1112.9	1092.7	1076.5	802.2	775.9	755.5
2023	1130.3	1110.2	1093.9	817.5	790.9	770.1
2024	1147.4	1127.3	1111.0	833.3	806.3	785.3
2025	1163.5	1143.4	1127.2	848.9	821.5	800.2
2026	1179.7	1159.6	1143.5	863.8	836.0	814.4
2027	1195.6	1175.5	1159.4	878.8	850.6	828.8
2028	1213.6	1193.5	1177.4	894.8	866.3	844.1
2029	1236.1	1216.1	1200.0	912.4	883.4	860.9
2030	1260.3	1240.3	1224.2	933.5	904.0	881.1
2031	1285.2	1265.2	1249.2	955.9	925.9	902.6
2032	1310.0	1290.0	1274.0	978.9	948.3	924.6
2033	1333.1	1313.1	1297.1	1001.9	970.7	946.5
2034	1354.2	1334.2	1318.3	1023.5	991.8	967.2
2035	1374.7	1354.8	1338.9	1043.7	1011.4	986.4
2036	1395.4	1375.4	1359.6	1063.3	1030.6	1005.3
2037	1416.4	1396.5	1380.6	1083.1	1049.9	1024.1
2038	1437.9	1418.0	1402.2	1103.2	1069.4	1043.3
2039	1460.0	1440.1	1424.3	1123.6	1089.4	1062.9
2040	1482.5	1462.6	1446.9	1144.5	1109.7	1082.8
2041	1505.5	1485.7	1469.9	1165.7	1130.4	1103.1
2042	1529.1	1509.2	1493.6	1187.3	1151.5	1123.8
2043	1553.2	1533.4	1517.7	1209.4	1173.0	1144.9
2044	1577.8	1558.0	1542.4	1231.9	1194.9	1166.4
2045				1254.7	1217.2	1188.3

Table D.8	Retail energy maximum demands (continued)					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
High scenario						
2015	1010.7	990.6	974.2	700.2	675.9	656.9
2016	1048.1	1027.9	1011.6	731.3	706.4	687.0
2017	1074.0	1053.8	1037.6	767.7	742.2	722.4
2018	1099.1	1079.0	1062.7	789.6	763.5	743.3
2019	1127.2	1107.1	1090.9	810.9	784.3	763.6
2020	1159.2	1139.1	1122.9	834.3	807.1	786.0
2021	1193.2	1173.2	1157.0	860.5	832.6	811.0
2022	1227.1	1207.0	1190.9	889.7	861.2	839.0
2023	1257.4	1237.4	1221.3	918.9	889.6	866.9
2024	1292.3	1272.3	1256.3	945.6	915.6	892.4
2025	1332.2	1312.3	1296.3	975.6	944.9	921.1
2026	1364.7	1344.7	1328.8	1009.4	977.8	953.4
2027	1395.6	1375.7	1359.9	1037.8	1005.5	980.5
2028	1419.1	1399.2	1383.4	1067.0	1033.9	1008.4
2029	1450.8	1430.9	1415.2	1090.6	1057.0	1031.0
2030	1486.1	1466.2	1450.5	1120.5	1086.1	1059.6
2031	1527.2	1507.4	1491.7	1153.2	1118.0	1090.8
2032	1569.4	1549.6	1534.0	1190.4	1154.3	1126.4
2033	1597.8	1578.0	1562.4	1228.7	1191.7	1163.0
2034	1622.1	1602.4	1586.8	1256.3	1218.6	1189.5
2035	1648.1	1628.3	1612.9	1280.9	1242.5	1212.9
2036	1676.7	1656.9	1641.5	1306.7	1267.7	1237.6
2037	1706.2	1686.5	1671.1	1334.5	1294.8	1264.2
2038	1736.3	1716.6	1701.3	1363.1	1322.7	1291.6
2039	1762.5	1742.9	1727.6	1392.2	1351.1	1319.4
2040	1790.5	1770.9	1755.6	1418.3	1376.5	1344.4
2041	1818.2	1798.6	1783.4	1445.8	1403.3	1370.7
2042	1849.5	1829.9	1814.7	1473.0	1429.9	1396.8
2043	1887.4	1867.8	1852.7	1503.1	1459.2	1425.5
2044	1921.7	1902.2	1887.1	1538.3	1493.6	1459.2
2045				1570.8	1525.3	1490.3

Table D.8	Retail energy maximum demands (continued)					
	Winter (these are calendar years)			Summer		
	10th	50th	90th	10th	50th	90th
Low scenario						
2015	989.7	969.5	953.1	679.9	656.1	637.4
2016	1003.3	983.1	966.7	693.7	669.7	651.0
2017	1005.2	985.0	968.6	710.9	686.9	668.1
2018	1006.2	986.0	969.6	712.9	688.8	670.0
2019	1007.5	987.3	970.9	714.2	690.1	671.2
2020	1009.8	989.6	973.2	715.7	691.6	672.7
2021	1016.2	996.0	979.6	717.8	693.7	674.8
2022	1025.1	1004.9	988.5	723.7	699.5	680.5
2023	1032.3	1012.1	995.7	731.5	707.0	687.9
2024	1039.0	1018.8	1002.3	737.9	713.3	694.1
2025	1044.5	1024.3	1007.9	743.9	719.2	699.8
2026	1050.0	1029.8	1013.4	749.2	724.3	704.9
2027	1055.3	1035.1	1018.7	754.3	729.3	709.8
2028	1062.2	1042.0	1025.6	760.3	735.1	715.5
2029	1071.8	1051.6	1035.3	767.4	742.1	722.3
2030	1082.3	1062.1	1045.7	776.6	751.1	731.2
2031	1092.7	1072.5	1056.2	786.5	760.7	740.6
2032	1103.3	1083.1	1066.8	796.4	770.4	750.1
2033	1112.2	1092.1	1075.8	806.2	779.9	759.5
2034	1119.4	1099.2	1082.9	814.8	788.3	767.6
2035	1125.7	1105.6	1089.3	821.9	795.2	774.5
2036	1131.9	1111.8	1095.5	828.4	801.6	780.7
2037	1138.1	1118.0	1101.7	834.7	807.7	786.7
2038	1144.5	1124.4	1108.1	841.1	814.0	792.8
2039	1151.1	1131.0	1114.7	847.6	820.3	799.1
2040	1157.8	1137.7	1121.4	854.2	826.7	805.4
2041	1164.7	1144.6	1128.3	860.9	833.3	811.8
2042	1171.7	1151.6	1135.3	867.7	839.9	818.3
2043	1178.9	1158.8	1142.6	874.6	846.7	825.0
2044	1177.4	1157.3	1141.1	881.7	853.6	831.7
2045				882.0	853.9	832.0

Appendix E: A brief description of major industrial and small major loads – Tasmania

1. Pacific Aluminium: Comalco 220 kV

The Bell Bay aluminium smelter is one of 22 smelters within the Rio Tinto Alcan group. It was Australia's first aluminium smelter and began production in 1955. Currently (2010), production is around 175,000 tonnes annually.

Aluminium is exported from Bell Bay to world markets, including the rapidly growing markets of China and India.

2. Norske Skog mill

The Norske Skog paper mill at Boyer has been in operation since 1941 and produces around 290,000 tonnes of newsprint and related grades.

Norske Skog is a Norwegian company and has 14 mills operating in 11 countries. It has two mills in Australia, the Boyer mill and Albury (New South Wales). Most of Boyer's production of newsprint is delivered to mainland Australia for use in publishing houses.

3. TEMCO (Tasmanian electro Metallurgical Company) station: TEMCO 110 kV

TEMCO is a manganese ferroalloy plant owned by BHP Billiton. It produces 250,000 tonnes of alloy, comprising of 130,000 tonnes of ferromanganese and 120,000 tonnes of silicomanganese. It is used by steel manufacturers in Australia and across the world in the production of steel. TEMCO exports 80 per cent of its alloys produced overseas.

TEMCO began production in 1962 and is located at Bell Bay.

4. Nyrstar (Zinifex) station: Risdon 11 kV

The zinc smelter at Hobart commenced operations in 1921. The smelter processes zinc electrolytically, hence the large power requirement.

Nyrstar was formed following the collapse of Pasminco in 2003. It comprises the Hobart smelter which includes the Rosebery mine in Western Tasmania, the Century mine in Queensland, a zinc smelter at Port Pirie (South Australia) and other smelters in the Netherlands and Tennessee in the United States. Nyrstar exports products from its Hobart smelter to Asia and particularly China. It currently produces around 250,000 tonnes annually of zinc metal.

5. Gunns paper mill (cancelled)

The Gunns paper mill was a proposed major pulp mill in the Tamar Valley. The project had State and Federal approvals, however, Gunns was unable to secure finance for the $2 billion plus project.

The proposed mill would produce 820,000 tpa of pulp from 3.2 million tonnes of wood per year. The pulp would be sold to domestic and international markets. Total power usage by the proposed plant will be of the order of 100 MW.

6. Emu Bay Paperlinx (APM)

The Burnie paper mill was closed in 2010 by Paperlinx. The Burnie mill produced around 128,000 tonnes of paper per year. The main fibre source for the Burnie mill was imported pulp.

7. Gunns Hampshire (previously North Forest Products) station: Hampshire 110 kV

Gunns operates a woodchip mill at Hampshire with a 24 hour, 7 day a week permitted operation. The Hampshire facility produces hardwood woodchips for export to the Asian markets and domestic customers. The capacity of the mill is some 1.6 million tonnes per annum.

8/12. Grange Resources (previously Australian Bulk Minerals) station: Savage River 22 kV and Port Latta 22 kV

Grange Resources operates an iron ore mine at Savage River and produces iron ore pellets at Port Latta. ABM has contracts with steel producers in Australia and Asia.

Production at Savage River and Port Latta commenced in 1966 with 45 Mt of pelletised iron over a 20 year period. ABM purchased the Savage River project from the Tasmanian Government in 1997. Grange Resources now owns this project.

The production process, in basic terms, is as follows:

(i) ore from Savage River mine is crushed to 200 mm and transported to a 1.3 km conveyor;

(ii) ore is fed into a concentrator and magnetic separators are used to isolate magnetite; and

(iii) metal concentrate is piped 83 km to Port Latta where they undergo pelletising in heat furnishes.

The mining lease is for 30 years. The current mine life is to 2023, but extensions are possible beyond this date.

9. Hellyer (Bass Metals) station: Que 22 kV

Bass Metals is a precious metals producer located at the Que River in north-west Tasmania. The Hellyer mine project commenced operations in 2010 from its Fossey mine. The Hellyer mill will produce 55,000 tpa of zinc concentrate, 27,000 tpa of lead concentrate and 5,000 tpa of copper/silver/gold concentrates.

Nyrstar signed an agreement to take all zinc and lead concentrates produced by the Fossey mine in January 2010.

Base Metals also has other potential assets which could be developed in the Fossey and Fossey East area.

10. Copper Mines of Tasmania station: Queenstown 11 kV

The Mount Lyell mine, a copper mine, first started production in 1996. It was re-opened by Copper Mines of Tasmania in 1996.

The mine currently produces around 30,000 tonnes of contained copper in concentrate. It provides 7 per cent of the copper requirements to its parent company's (Sterlite) copper smelter in Tuticorin, India.

Primary crushing is underground. The ore is then lifted up a shaft (i.e. underground mining) to be transported to the concentrator via a 1.2 km over-land conveyer belt. The ore is then crushed to a fine slurry, then concentrated.

Current reserves are some 9.5 million tonnes of ore at 1.25 per cent cu.

11. Zinifex Rosebery mine station: Rosebery 44 kV

The Zinifex Rosebery mine is an underground zinc, copper, gold mine located on the west coast of Tasmania.

Ore production has increased significantly over recent years from 600,000 tpa in 2000 to over 850,000 tpa in 2010. At current production rates the mine has a life of around eight years.

Exploration around the Rosebery mine has been initiated with the view to extending the mine life.

MMG are also proposing constructing an open cut mine (South Hercules mine) at Mt Hamilton. Ore would be processed at MMG's existing Rosebery mine. Exploration drilling is also being conducted at the Jupiter mine, some 4 kilometres from the township of Rosebery.

13. Gunns Bell Bay (previously Forest Enterprises) station: Starwood

Gunns (Bell Bay) manages significant eucalypt plantations in Tasmania, New South Wales and Victoria.

A large medium density fibreboard (MDF) plant is located at Bell Bay on the Tamar River. The plant was commissioned in 1998. The plant produces 120,000 tonnes of MDF per annum and exports to South East Asia, New Zealand and Australia.

14. Wesley Vale – Paperlinx (APM)

Paperlinx announced the closure of tis Wesley Vale paper mill in December 2009.

The Wesley Vale mill included two pulp mills, a paper machine and an off machine coater. The mill produced 40,000 tonnes of pump and 135,000 tonnes of coated and uncoated papers per annum.

15. Forestry Tasmania station: Huon River 22 kV

Forestry Tasmania is milling in the Huon region of Tasmania.

Appendix F: PeakSim metrics

In Chapter 6, projections of maximum demand are presented for the next 10-years. These projections have been developed within the National Institute's PeakSim model. PeakSim is a simulation model which generates 'probability of exceedance' (PoE) distribution of maximum demand. The model projects future probability distributions by linking broad economic indicators to the key model parameters (temperature insensitive and sensitive parameters).

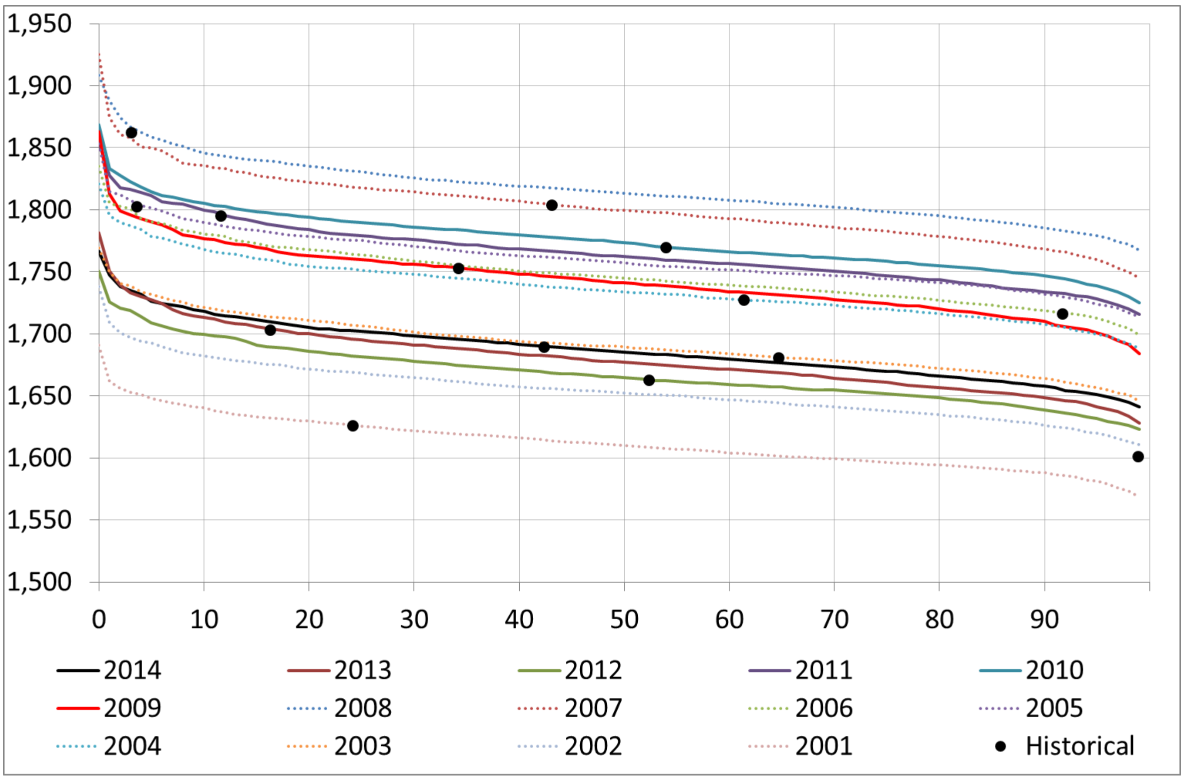
This section examines some of the other metrics and useful diagnostic computed by the model for Transcend Network Demand.

Implied historical PoE distribution

The discussion in Chapter 6 focuses on projected maximum demand for three key probability levels: 10%, 50% and 90%. The model underlying these three projections generates projections for the full spectrum of probability levels.

Figure F.1 shows probability of exceedance curves of maximum demand (as implied by the model) for each winter over the past 15 years. The chart illustrates the likelihood of maximum demand level for a given year. The y-axis (i.e. the vertical axis) measures the maximum demand level in megawatts (MW) while the x-axis (the horizontal axis) measures probability of exceedance levels (expressed as a percentage). The time dimension is represented by the different coloured lines.

Figure F.1: Implied winter maximum demand (MW) for each % probability of exceedance



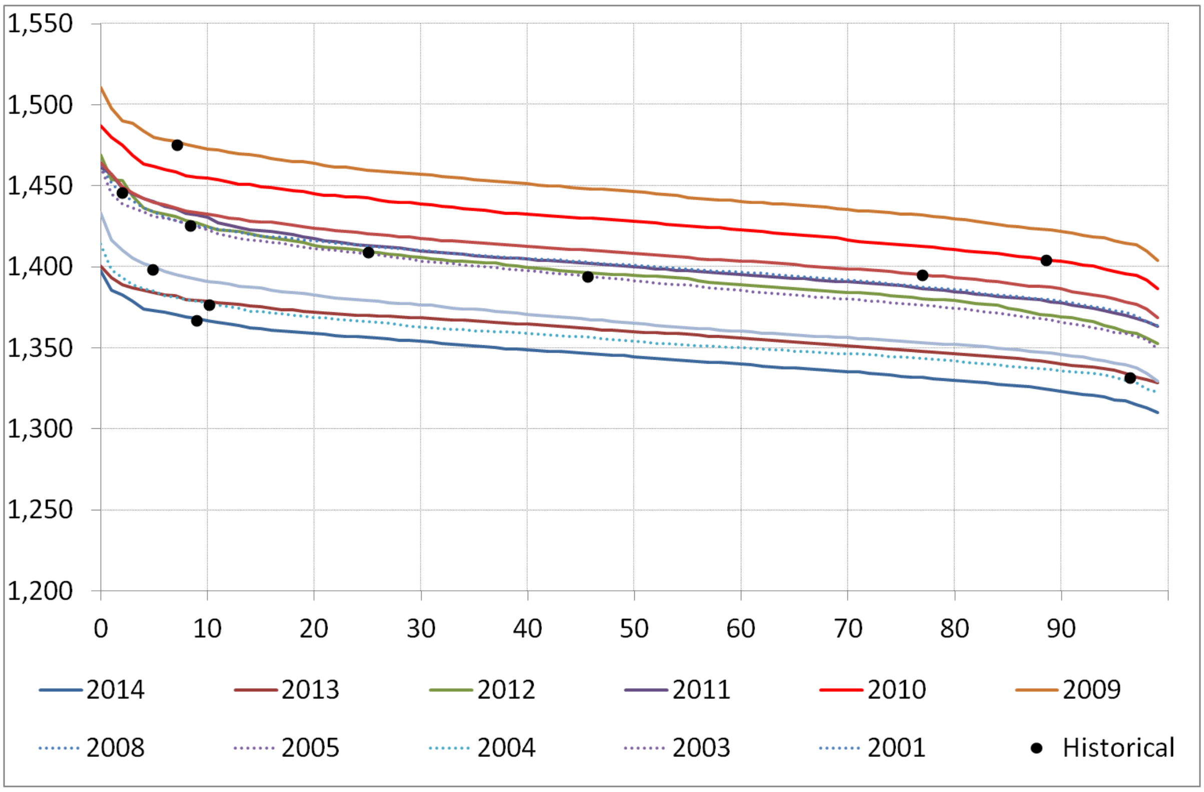
Each line on this chart represents a different winter; for instance, the red line at the top shows the 2008 winter. It shows the full range of possible maximum demand levels[11] that could have occurred in winter 2008. Please note this curve is quite different from a duration curve. It shows the potential levels of maximum demand for the specific season given the prevailing economic environment, seasonal conditions and stock of technology in use.[12] It shows the levels of maximum demand if extreme weather conditions and consumer responses to other prevailing conditions had been different.

These curves shows that the shape of the probability distribution has remained relatively constant over the past 15 years although the level of the curve have moved up and down with changes in the economic environment, seasonal conditions and stock of technology in use. In recent winter, the overall level of curve has fallen considerably. The black line represents the winter 2014 curve. This curve is substantially below the curve for winter 2008.

The black dot on the each curve shows the level of maximum demand observed during the respective winter. From position of the dot, one can infer the implied probability of exceedance percentage (as shown on x-axis). For instance, the winter maximum demand in 2014 was 1689 MW; this equates approximately to a 44% probability of exceedance.

Figure F.2 shows the corresponding probability of exceedance curves of maximum demand for summers over the past 15 years.

Figure F.2: Implied summer maximum demand (MW) for each % probability of exceedance



[11] As implied by model given the economic and seasonal conditions.

[12] Seasonal factors can also impact the level of the curves.

As has been observed in recent summers, the probability of exceedance curve has fallen somewhat in recent winters.

Model accuracy

To measure the "accuracy" of the modelling, the National Institute has applied two different approaches.

One approach is simply based on the common point-estimate accuracy measures such as a root mean squared error (RMSE) statistic. We would expected, on average, most of the observed maximum demand events to congregate around the historical implied 50% Probability of Exceedance value as this is the centre of the distribution. A RMSE type measures attempt to detect any bias in the implied outcomes relative to the 50% Probability of Exceedance value.

The second approach attempts to gauge the accuracy of the whole probability distribution; not just relative to the centre of the distribution. This approach compares the relative dispersion of observed maximum demand events with the probability distribution implied from the model.

The logic of this second approach is quite simply. For illustration, consider the following example. Over a 10-year period one would expect (on average) a 10% Probability of Exceedance maximum demand level to be exceeded just once. Extending this logic further, one would expect a 20% Probability of Exceedance maximum demand level to be exceeded just twice over a ten year period. Furthermore, we would expect a 30% Probability of Exceedance maximum demand level to be exceeded just thrice over a ten year period ….. and so on, and so on. This logic can be extended across the whole probability distribution.

For a given historical period, the *expected* number of maximum demand events for each probability of exceedance level can be compare with the *observed* number of maximum demand events above that probability of exceedance level. The absolute difference between the expected number of events and the observed number of events provides a gauge of the relative accuracy at various points in the distribution. The absolute difference is often expressed as a percentage of total number of periods and is called the 'excess percentage'. Kolmogorov-Smirnov Statistics for the absolute excess percentage is another way of expressing the excess percentage.[13]

There are several limitations to first and second approaches. An important limitation of both approaches is that they may lead to erroneous conclusions about the relative accuracy of the modelling if the sample size is small (i.e. where the sample size is less than 25 observations). A key difficulty in measuring the accuracy of a probabilistic model is that parts of probability distribution, namely the extreme tails, are rarely observed; for instance, 10% probability of exceedance level is expected, on average, to be exceed once in a ten-year period. By definition, a historical sample of nine observations may not even contain a 10% probability of exceedance event.

Results

Tables F.1 and F.2 present accuracy statistics for implied historical 50% of probability of exceedance level for past winters and summers respectively

[13] See Hyndman (2008) 'Evaluating peak demand forecasts' ESIPC website (www.esipc.sa.gov.au), for discussion of this measure.

Table F.1	Accuracy measures of implied 50% probability of exceedance winter maximum demand level
Sample	2000-2014
Number of observations:	15
Root Mean Squared Error	27.2
Root Mean Square Percentage Error	1.6%
Mean Absolute Error	21.6
Mean Absolute Percentage Error	1.3%
Theil Inequality coefficient	0.8%
Bias Proportion	1.2%
Variance Proportion	36.7%
Covariance proportion	62.2%
Bias Proportion	1.2%
Regression Proportion	21.8%
Disturbance proportion	77.1%
Kolmogorov-Smirnov Statistics	1.95

Note: * Insufficient data points to draw valid inference from these statistics.
Source: PeakSim.

Table F.2	Accuracy measures of implied 50% probability of exceedance summer maximum demand level
Sample	1999-2014
Number of observations:	13
Root Mean Squared Error	24.1
Root Mean Square Percentage Error	1.7%
Mean Absolute Error	21.9
Mean Absolute Percentage Error	1.6%
Theil Inequality coefficient	0.9%
Bias Proportion	8.6%
Variance Proportion	21.2%
Covariance proportion	70.2%
Bias Proportion	8.6%
Regression Proportion	7.0%
Disturbance proportion	84.4%
Kolmogorov-Smirnov Statistics	4.57

Note: * Insufficient data points to draw valid inference from these statistics.
Source: PeakSim.

The root measure square error is a commonly-used measure of the difference between predicted and observed values. This statistic suggests that, on average, the difference between observed maximum demand and implied 50% probability of exceedance level is approximately 27 MW. Root mean square percentage error is a variant of the root measure square error.

The mean absolute error is a similar measure of difference. The mean absolute percentage error measures the difference in expected and observed values as proportion of the observed value. This measure provides a scale to the difference between expected and observed values.

The Theil inequity coefficient is another popular measure of difference. (For reference, this measure is based on the U1 formulation). The coefficient can be decomposing into two separate ways:

1. bias, variance, and covariance proportions; and
2. bias, regression and disturbance proportions.

The bias proportion measures how far the mean of the expected values is from the mean of the observed values. The variance proportion measures how far the variance of the expected values is from the variance of the observed values. The covariance proportion measures the remaining unsystematic difference.

The regression proportion measures of how far the systematic component of expected values is from the systematic component of the observed values. The disturbance proportion measures the remaining unsystematic difference.

The bias, variance and covariance proportions sum to 1. Similarly, the bias, regression and disturbance proportions sum to 1. Expected values are considered good predictors, if the bias and variance proportion are small or bias and regression proportions are small.

The Figure F.3 shows the number of maximum demand events expected over a 15-year period for each probability of exceedance levels (blue line) and the number of maximum demand events over the past 15 summers for each probability of exceedance levels (red line) as implied by the model. This figure indicates that the observed maximum demand events deviate only slightly from the expected number of maximum demand in many parts of the probability spectrum.

Figure F.3: Observed and implied number of maximum demand events for past winters

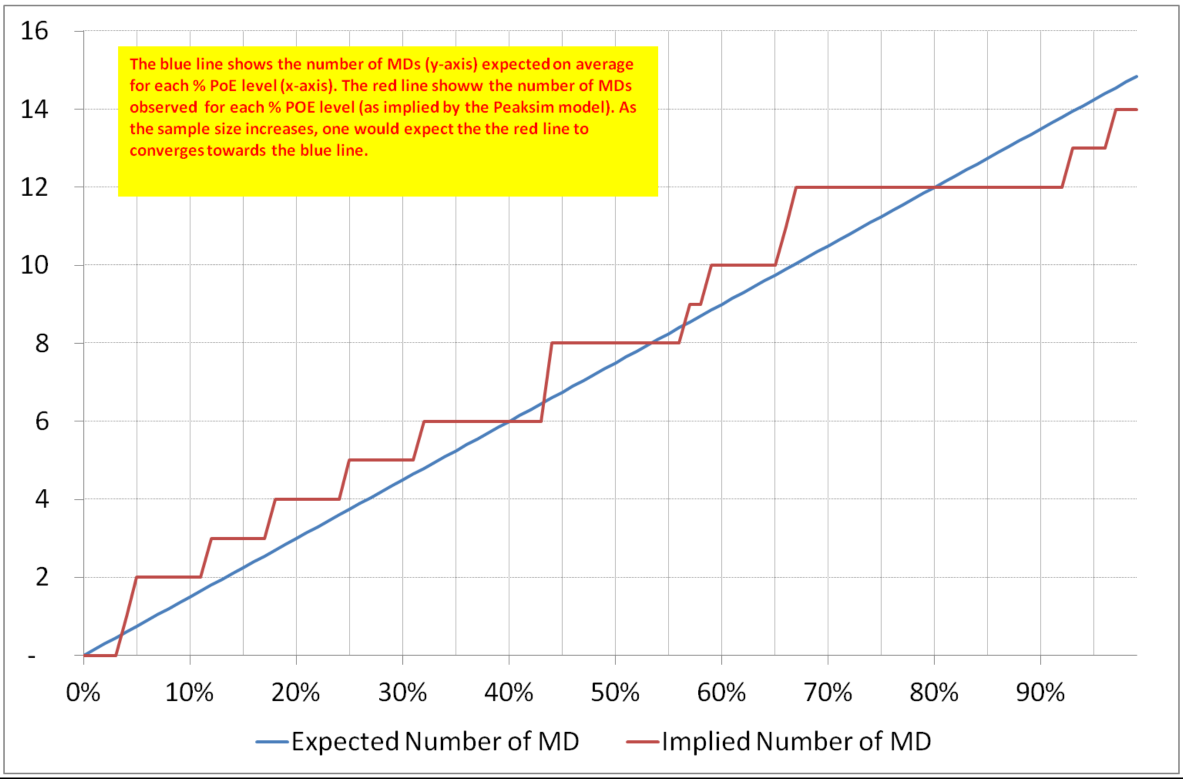
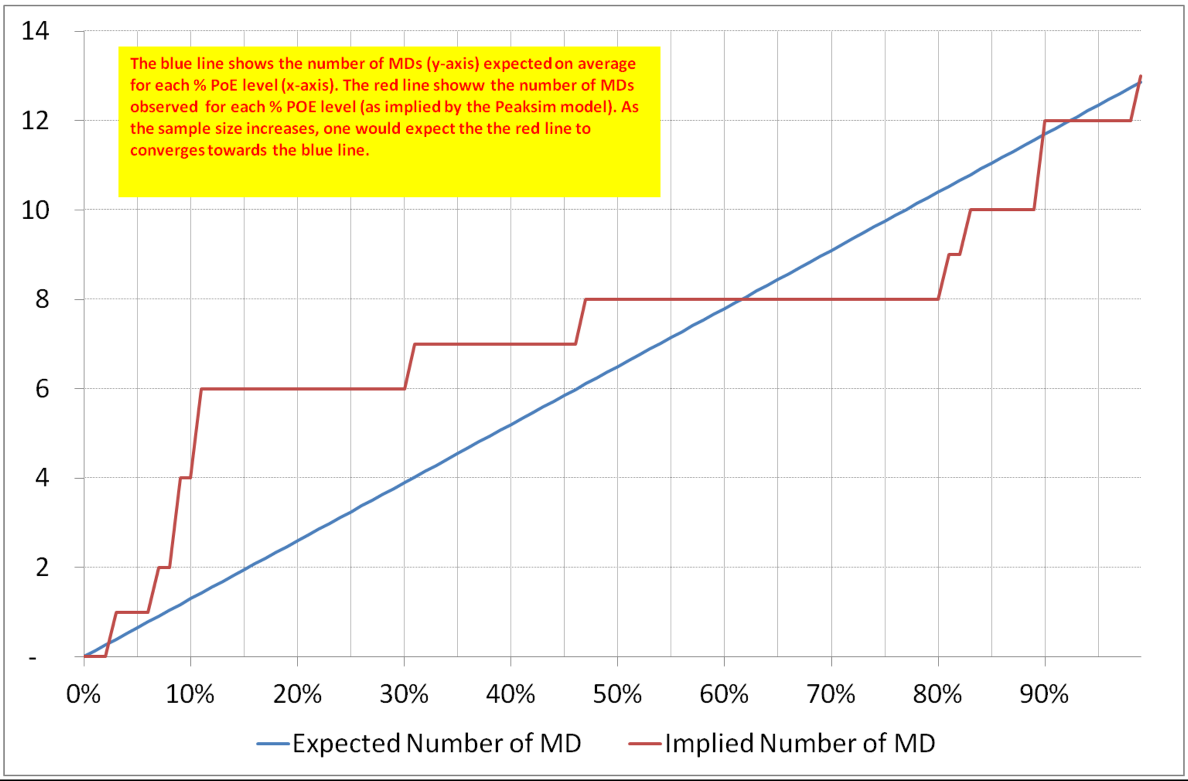


Figure F.4: Observed and implied number of maximum demand events for past summers



The Kolmogorov-Smirnov Statistics for the absolute excess percentage for both summer and winter is 3.3 observations. This suggest that the projections (at most) under- or over-predicts the number of maximum demand events by 3.3 at any point on the distribution.

Model parameters

As noted earlier in the report, the PeakSim is structured around sequence of regression equations that segments demand into temperature sensitive and temperature insensitive components. Tables F.5 and F.6 present estimated parameters (coefficients and r-squared) from these regression equations for winter and summer respectively.

The temperature variable for the summer regressions is formulated as:

Max (0, Temp-18)

where Temp = (1/3)*(HH Temp)+(1/3)*(MaxTemp)+(1/3)*(MinTemp).

The temperature variable for the winter regressions is formulated as:

Max (0, 20-Temp)

where Temp = (1/3)*(HH Temp)+(1/3)*(MaxTemp)+(1/3)*(MinTemp).

Friday, Saturday, Sunday, AusDay, QBday and Outlier are dummy variables.

Table F.3	Estimated model parameters for winter							
Period	**Year**	**Intercept**	**Temperature**	**Saturday**	**Sunday**	**QBDay**	**Outlier**	**R-squared**
8:30am	2000	1,357	19.3	-211	-283	-209	-	0.93
	2001	1,380	15.8	-223	-307	-	-	0.94
	2002	1,402	17.7	-209	-276	-	-	0.94
	2003	1,443	17.1	-260	-310	-	-	0.89
	2004	1,456	20.4	-253	-319	-384	-330	0.93
	2005	1,477	20.4	-221	-281	-292	-	0.89
	2006	1,448	22.3	-262	-331	-262	-	0.92
	2007	1,477	24.4	-254	-313	-	-	0.94
	2008	1,544	19.1	-254	-301	-	-	0.91
	2009	1,421	24.4	-231	-316	-	-	0.94
	2010	1,499	19.8	-241	-296	-266	-	0.90
	2011	1,489	19.5	-237	-307	-345	-	0.90
	2012	1,387	20.8	-234	-284	-294	-	0.85
	2013	1,358	24.6	-205	-227	-	-	0.87
	2014	1,413	19.7	-216	-262	-	-	0.81

Note: Sample period includes weeks 25 to 34.

Table F.4	Estimated model parameters for summer							
Period	**FYear**	**Intercept**	**Temperature**	**Saturday**	**Sunday**	**Regatta Day**	**Outlier**	**R-squared**
7:00pm	2000	1,114.0	2.2	-	-	15.0	-151.0	0.75
	2002	1,142.4	7.1	-	-	-75.6	-	0.54
	2003	1,135.3	9.8	-	-	-77.4	-46.2	0.57
	2004	1,128.6	3.6	-	-	-117.6	-	0.41
	2007	1,269.1	14.1	-	-	-99.5	-	0.81
	2008	1,262.3	14.3	-	-	-128.2	-77.7	0.54
	2009	1,296.0	15.7	-	-	-158.2	-	0.73
	2010	1,279.1	15.7	-	-	-65.6	-	0.58
	2011	1,260.0	14.5	-	-	-99.9	-	0.64
	2012	1,242.9	15.0	-	-	-116.4	-130.6	0.61
	2013	1,248.7	9.6	-	-	-126.3	57.1	0.60
	2014	1,222.3	11.6	-	-	-136.9	-	0.57
7:30pm	2000	1,177.7	3.8	-	-	-10.9	-145.4	0.56
	2002	1,212.0	11.3	-	-	-108.8	-	0.65
	2003	1,205.5	13.7	-	-	-110.2	-51.2	0.61
	2004	1,200.4	7.5	-	-	-128.9	-	0.46
	2007	1,272.3	13.8	-	-	-72.4	-	0.77
	2008	1,268.9	12.2	-	-	-103.3	-80.8	0.49
	2009	1,303.3	15.0	-	-	-140.6	-	0.61
	2010	1,276.5	15.8	-	-	-37.5	-	0.50
	2011	1,259.2	14.8	-	-	-75.5	-	0.62
	2012	1,240.1	18.0	-	-	-90.7	-48.2	0.61
	2013	1,253.1	8.2	-	-	-109.5	55.9	0.48
	2014	1,218.7	12.1	-	-	-106.1	-	0.56

Table F.4	Estimated model parameters for summer (continued)							
Period	**FYear**	**Intercept**	**Temperature**	**Saturday**	**Sunday**	**Regatta Day**	**Outlier**	**R-squared**
8:00pm	2000	1,208.4	7.9	-	-	-22.4	-140.6	0.52
	2002	1,244.5	12.9	-	-	-107.9	-	0.72
	2003	1,237.6	18.2	-	-	-115.7	-64.3	0.64
	2004	1,247.6	9.1	-	-	-135.3	-	0.47
	2007	1,260.1	12.1	-	-	-46.0	-	0.64
	2008	1,260.9	9.0	-	-	-54.4	-134	0.46
	2009	1,283.3	14.8	-	-	-88.2	-	0.58
	2010	1,260.3	16.7	-	-	1.1	-	0.56
	2011	1,247.9	13.3	-	-	-39.3	-	0.57
	2012	1,229.6	16.4	-	-	-54.5	-39.8	0.60
	2013	1,235.4	9.0	-	-	-88.1	-208.2	0.66
	2014	1,202.6	11.0	-	-	-75.4	-	0.51
8:30pm	2000	1,201.7	7.2	-	-	16.3	-125.8	0.57
	2002	1,236.4	12.6	-	-	-85.2	-	0.61
	2003	1,242.9	16.9	-	-	-102.3	-116.1	0.66
	2004	1,252.1	9.0	-	-	-103.7	-	0.42
	2007	1,248.3	10.9	-	-	-2.9	-	0.55
	2008	1,247.1	8.0	-	-	-23.5	-53.0	0.35
	2009	1,267.8	13.8	-	-	-70.0	-	0.55
	2010	1,245.5	16.5	-	-	7.1	-	0.51
	2011	1,237.6	12.6	-	-	-13.3	-	0.50
	2012	1,223.9	13.4	-	-	-20.5	-58.8	0.52
	2013	1,221.0	7.5	-	-	-60.9	-0.9	0.22
	2014	1,189.4	9.2	-	-	-58.1	-	0.46

Glossary

Adjusted *R-Squared*	A goodness-of-fit measure in multiple regression analysis that penalises additional explanatory variables by using a degrees of freedom adjustment in estimating the error variance.
Ampere (amp)	The unit of measurement of electric current. It is the unit current produced in a circuit by one volt acting across a resistance of one ohm.
Australian Competition and Consumer Commission (ACCC)	Enforces the *Trade Practices Act* and the *Prices Surveillance Act*. In particular, it authorises (or prevents) mergers and acquisitions and authorises anti-competitive agreements. The ACCC was established under the *Commonwealth Trade Practices Act* of 1974.
Autoregressive Process of Order One [AR(1)]	A time series model whose current value depends linearly on its most recent value plus an unpredictable disturbance.
Base value	The value assigned to the base period for constructing an index number, usually the base value is 1 or 100.
Best Linear Unbiased Estimator (BLUE)	Among all linear unbiased estimators, the estimator with the smallest variance. OLS is BLUE, conditional on the sample values of the explanatory variables, under the Gauss-Markov assumptions.
Bias	The difference between the expected value of an estimator and the population value that the estimator is supposed to be estimating.
Bootstrap	A resampling method that draws random samples, with replacement, from the original data set.
Breusch-Pagan Test	A test for heteroskedasticity where the squared OLS residuals are regressed on the explanatory variables in the model.
Central Limit Theorem (CLT)	A key result from probability theory that implies that the sum of independent random variables, or even weakly dependent random variables, when standardised by its standard deviation, has a distribution that tends to standard normal as the sample size grows.
Ceteris Paribus	All other relevant factors are held fixed.
Chi-Square distribution	A probability distribution obtained by adding the squares of independent standard normal random variables. The number of terms in the sum equals the degrees of freedom in the distribution.
Chow statistic	An *F* statistic for testing the equality of regression parameters across different groups (say, men and women) or time periods (say, before and after a policy change).
Classical Linear Model	The multiple linear regression model under the full set of classical linear model assumptions.
Coefficient of determination	*See R-squared.*
Cointegration	The notion that a linear combination of two series, each of which is integrated of order one, is integrated of order zero.

Column vector	A vector of numbers arranged as a column.
Combined cycle generator	An electric generating unit in which electricity is produced from waste heat exiting from one or more combustion turbines. This process increases the efficiency of the electric generating unit.
Conditional distribution	The probability distribution of one random variable, given the values of one or more other random variables.
Conditional expectation	The expected or average value of one random variable, called the dependent or explained variable, that depends on the values of one or more other variables, called the independent or explanatory variables.
Conditional forecast	A forecast that assumes the future values of some explanatory variables are known with certainty.
Confidence interval (CI)	A rule used to construct a random interval so that a certain percentage of all data sets, determine3d by the confidence level, yields an interval that contains the population value.
Confidence level	The percentage of samples in which we want our confidence interval to contain the population value; 95 per cent is the most common confidence level, but 90 and 99 per cent are also used.
Correlation coefficient	A measure of linear dependence between two random variables that does not depend on units of measurement and is bounded between 1 and 1.
Covariance	A measure of linear dependent between two random variables.
Cross-sectional data set	A data set collected by sampling a population at a given point in time.
Data frequency	The interval at which time series data are collected. Yearly, quarterly and monthly are the most common data frequencies.
Degrees of freedom (*df*)	In multiple regression analysis, the number of observations minus the number of estimated parameters.
Demand	The amount of electricity being consumed by customers at any given time.
Demand side participation (DSP)	Refers to a voluntary reduction in net demand, typically in response to a pool price signal, achieved either by switching off a load or running an embedded generator to reduce the net level of demand. Although the NEC provides scope for participants to bid their loads directly into the pool, DSP is more usually an off market arrangement negotiated directly between a participant and an end-user of electricity or the owner of an embedded generator. The extent and terms of these bilateral contracts are not publicly available, making it difficult to predict future levels of DSP. DSP may also be referred to as demand side response, load curtailment contracts or demand side management.
Dependent variable	The variable to be explained in a multiple regression model (and a variety of other models).

Descriptive statistic	A statistic used to summarise a set of numbers; the sample average, sample median and sample standard deviation are the most common.
Deseasonalising	The removing of the seasonal components from a monthly or quarterly time series.
Detrending	The practice of removing the trend from a time series.
Distributed Lag Model	A time series model that relates the dependent variable to current and past values of an explanatory variable.
Distribution network	The system of wires, switches, transformers and other related infrastructure that delivers electricity from the high-voltage transmission network to the end-use consumer for use in homes and businesses.
Disturbance	*See error term*.
Downward bias	The expected value of an estimator is below the population value of the parameter.
Durbin-Watson (DW) statistic	A statistic used to test for first order serial correlation in the errors of a time series regression model under the classical linear model assumptions.
Econometric Model	An equation relating the dependent variable to a set of explanatory variables and unobserved disturbances, where unknown population parameters determine the ceteris paribus effect of each explanatory variable.
Elasticity	The percentage change in one variable given a 1 per cent ceteris paribus increase in another variable.
Electricity Statement of Opportunities (ESOO)	An annual electricity document released by AEMO in accordance with the *National Electricity Rules*.
Embedded generators	A generator whose generating units are connected to a distribution system (rather than the high voltage transmission system). Such generators are usually small and often cogeneration facilities.
Empirical analysis	A study that uses data in a formal econometric analysis to test a theory, estimates a relationship, or determines the effectiveness of a policy.
Error Correction Model	A time series model in first differences that also contains an error correction term, which works to bring two I(1) series back into long-run equilibrium.
Error term	The variable in a simple or multiple regression equation that contains unobserved factors that affect the dependent variable. The error term may also include measurement errors in the observed dependent or independent variables.
Estimate	The numerical value taken on by an estimator for a particular sample of data.
Estimator	A rule for combining data to produce a numerical value for a population parameter; the form of the rule does not depend on the particular sample obtained.

Exogenous variable	Any variable that is uncorrelated with the error term in the model of interest.
Expected value	A measure of central tendency in the distribution of a random variable, including an estimator.
***F* Distribution**	The probability distribution obtained by forming the ratio of two independent chi-square random variables, where each has been divided by its degrees of freedom.
F Statistic	A statistic used to test multiple hypotheses about the parameters in a multiple regression model.
First difference	A transformation on a time series constructed by taking the difference of adjacent time periods, where the earlier time period is subtracted from the later time period.
First order autocorrelation	For a time series process ordered chronologically, the correlation coefficient between pairs of adjacent observations.
Fitted values	The estimated values of the dependent variable when the values of the independent variables for each observation are plugged into the OLS regression line.
Forced outage	The shutdown of a generating unit, transmission line or other asset for either emergency reasons or unexpected breakdown.
Forecast error	The difference between the actual outcome and the forecast of the outcome.
Forecast interval	In forecasting, a confidence interval for a yet unrealised future value of a time series variable. (*See also* prediction interval.)
Generator	A machine that converts mechanical energy into electrical energy.
Gigg	A prefix used to denote 1,000,000,000 (one billion) units.
Gigawatt (GW)	One gigawatt equals 1 billion watts, 1 million kilowatts or 1 thousand megawatts.
Gigawatt-hour (GWh)	One gigawatt-hour equals one billion watt-hours.
Growth rate	The proportionate change in a time series from the previous period. It may be approximated as the difference in logs or reported in percentage form.
Hypothesis test	A statistical test of the null, or maintained, hypothesis against an alternative hypothesis (e.g. *t* statistic).
Identified equation	An equation whose parameters can be consistently estimated, especially in models with endogenous explanatory variables.
Index number	A statistic that aggregates information on economic activity, such as production or prices.
Instrumental variables (IV) estimator	An estimator in a linear model used when instrumental variables are available for one or more endogenous explanatory variables.
Intercept	In the equation of a line, the value of the *y* variable when the *x* variable is zero.

Inter-regional Planning Committee (IRPC)	A planning group established under the *National Electricity Rules* that reviews matters of interstate supply and connection within the NEM.
Interruptible load	Load which is able to be disconnected, either manually or automatically, from the power system at times of power system stress. This assists with the restoration or control of the power system frequency at such times.
Joint distribution	The probability distribution determining the probabilities of outcomes involving two or more random variables.
Joule	Unit of energy (1 watt-sec) under the international system.
Kilo	A prefix used to denote 1,000 (one thousand) units.
Kilovolt (kV)	The unit of electrical potential equal to 1,000 volts.
Kilovolt-ampere (kVA)	One kilovolt-ampere equals 1,000 volt-amperes.
Kilowatt (kW)	One kilowatt equals 1,000 watts.
Kilowatt-hour (kWh)	The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt-hour equals 1,000 watt-hours. One kilowatt-hour can power ten 100 watt light bulbs for one hour.
Kurtosis	A measure of the thickness of the tails of a distribution based on the fourth moment of the standardised random variable; the measure is usually compared to the value for the standard normal distribution, which is three.
Lag distribution	In a finite or infinite distributed lag model, the lag coefficients graphed as a function of the lag length.
Lagged dependent variable	An explanatory variable that is equal t the dependent variable from an earlier time period.
Lagged endogenous variable	In a simultaneous equations model, a lagged value of one of the endogenous variables.
Lagrange Multiplier (LM) statistic	A test statistic with large sample justification that can be used to test for omitted variables, heteroskedasticity, and serial correlation, among other model specification problems.
Least squares estimator	An estimator that minimises a sum of squared residuals.
Likelihood ratio statistic	A statistic that can be used to test single or multiple hypotheses when the constrained and unconstrained models have been estimated by maximum likelihood. The statistic is twice the difference in the unconstrained and constrained log-likelihoods.
Limited Dependent Variable (LDV)	A dependent or response variable whose range is restricted in some important way.
Linear function	A function where the change in the dependent variable, given a one-unit change in an independent variable, is constant.
Load	The amount of electricity needed to meet demand at any given time.

Logarithmic function	A mathematical function defined for positive arguments that have a positive, but diminishing, slope.
Log function	A mathematical function, defined only for strictly positive arguments, with a positive but decreasing slope.
Log-likelihood function	The sum of the log-likelihoods, where the log-likelihood for each observation is the log of the density of the dependent variable given the explanatory variables; the log-likelihood function is viewed as a function of the parameters to be estimated.
Long-run elasticity	The long-run propensity in a distributed lag model with the dependent and independent variables in logarithmic form; thus, the long-run elasticity is the eventual percentage increase in the explained variable, given a permanent 1 per cent increase in the explanatory variable.
Long-run multiplier	*See* long-run propensity.
Long-run propensity (LRP)	In a distributed lag model, the eventual change in the dependent variable given a permanent, one-unit increase in the independent variable.
Loss factor	A multiplier used to describe the additional electrical energy loss for each increment of electricity used or transmitted.
Losses	For the end-user to obtain electricity at the desired location and at the desired voltage level, electricity must be transmitted through wires and transformed. Throughout this process some electricity-energy is converted into heat-energy resulting in the 'loss' of end-use electricity.
Mandatory Renewable Energy Target (MRET)	The Federal Government initiative to initiate 9,500 GWh of renewable energy from the electricity market by 2010.
Marginal effect	The effect on the dependent variable that results from changing an independent variable by a small amount.
Market participant	A person who has registered with AEMO as either a market generator or a market customer under Chapter 2 of the *National Electricity Rules*.
Maximum likelihood estimation (MLE)	A broadly applicable estimation method where the parameter estimates are chosen to maximise the log-likelihood function.
Maximum likelihood estimator	An estimator that maximises the (log of) likelihood function.
Mean	*See* expected value.
Mean absolute error (MAE)	A performance measure in forecasting, computed as the average of the absolute values of the forecast errors.
Mean squared error (MSE)	The expected squared distance that an estimator is from the population value; it equals the variance plus the square of any bias.
Measurement error	The difference between an observed variable and the variable that belongs in a multiple regression equation.

Median	In a probability distribution, it is the value where there is a 50 per cent chance of being below the value and a 50 per cent chance of being above it. In a sample of numbers, it is the middle value after the numbers have been ordered.
Mega	A prefix used to denote 1,000,000 (one million) units.
Megawatt (MW)	One megawatt equals one million watts.
Megawatt-hour (MWh)	One megawatt-hour equals one million watt-hours. One MWh of electricity can power ten thousand 100 watt light bulbs for one hour.
Missing data	A data problem that occurs when we do not observe values on some variables for certain observations (individuals, cities, time periods, and so on) in the sample.
Mode	Most common value.
Multicollinearity	A term that refers to correlation among the independent variables in a multiple regression model; it is usually invoked when some correlations are 'large', but an actual magnitude is not well defined.
Multiple Linear Regression (MLR) Model	A model linear in its parameters where the dependent variable is a function of independent variables plus an error term.
Multiple regression analysis	A type of analysis that is used to describe estimation of and inference in the multiple linear regression model.
National Competition Council (NCC)	Authorises the release of the competition payments under National Competition Policy.
National Electricity Rules (the NER)	The Rules governing the operation of the National Electricity Market and approved by Ministers of the participating jurisdictions for the time being in accordance with its terms and the National Electricity Law.
National Electricity Market (NEM)	A wholesale electricity market that allows market participants (generators and electricity customers) to trade electricity according to the NEC specifications.
National Electricity Market Management Company (NEMMCO)	Body established to have responsibility for day-to-day operation of the national market in accordance with the *National Electricity Rules*.
Network	The apparatus, equipment and plant used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets.
Nominal variable	A variable measured in nominal or current dollars.
Non-linear function	A function whose slope is not constant.
Non-stationary process	A time series process whose joint distributions are not constant across different epochs.
Normal distribution	A probability distribution commonly used in statistics and econometrics for modelling a population. Its probability distribution function has a bell shape.

Null hypothesis	In classical hypothesis testing, we take this hypothesis as true and require the data to provide substantial evidence against it.
Numerator degrees of freedom	In an *F* test, the number of restrictions being tested.
Observational data	*See* non-experimental data.
Off-peak	A time span of lower electricity usage, which would typically include public holidays, weekends and 9:00 p.m. to 7:00 a.m. on weekdays.
OLS	*See* ordinary least squares.
OLS intercept estimate	The intercept in an OLS regression line.
OLS regression line	The equation relating the predicted value of the dependent variable to the independent variables where the parameter estimates have been obtained by OLS.
OLS slope estimate	A slope in an OLS regression line.
Ordinary least squares (OLS)	A method for estimating the parameters of a multiple linear regression model. The ordinary least squares estimates are obtained by minimising the sum of squared residuals.
Outliers	Observations in a data set that are substantially different from the bulk of the data, perhaps because of errors or because some data are generated by a different model than most of the other data.
Overall significance of a regression	A test of the joint significance of all explanatory variables appearing in a multiple regression equation.
***p*-Value**	The smallest significance level at which the null hypothesis can be rejected. Equivalently, the largest significance level at which the null hypothesis cannot be rejected.
Parameter	An unknown value that describes a population relationship.
Peak	A time span of higher electricity usage, which would normally include non-holiday weekdays from 7:00 a.m. to 9:00 p.m.
Percentage change	The proportionate change in a variable, multiplied by 100.
Percentage point change	The change in a variable that is measured as a percentage.
Perfect collinearity	In multiple regression, one independent variable is an exact linear function of one or more other independent variables.
Point forecast	The forecasted value of a future outcome.
Poisson distribution	A probability distribution for count variables.
Policy analysis	An empirical analysis that uses econometric methods to evaluate the effects of a certain policy.
Pool	Common name for the wholesale electricity market. It is a spot market for electricity whereby sellers bid into the pool the advance prices of quantities of electricity, and generators are dispatched to meet the demand.
Prediction	The estimate of an outcome obtained by plugging specific values of the explanatory variables into an estimated model, usually a multiple regression model.

Prediction error	The difference between the actual outcome and a prediction of that outcome.
Prediction interval	A confidence interval for an unknown outcome on a dependent variable in a multiple regression model.
Probability density function (pdf)	A function that, for discrete random variables, gives the probability that the random variable takes on each value; for continuous random variables, the area under the pdf gives the probability of various events.
Proxy variable	An observed variable that is related but not identical to an unobserved explanatory variable in multiple regression analysis.
***R*-Square**	In a multiple regression model, the proportion of the total sample variation in the dependent variable that is explained by the independent variable.
Random sample	A sample obtained by sampling randomly from the specified population.
Random sampling	A sampling scheme whereby each observation is drawn at random from the population. In particular, no unit is more likely to be selected than any other unit, and each draw is independent of all other draws.
Reduced form equation	A linear equation where an endogenous variable is a function of exogenous variables and unobserved errors.
Regional reference node	A location on the transmission or distribution network established by AEMO in accordance with Clause 3.5.1 of the *National Electricity Rules*. This location is established as the pricing centre for a particular region through which, notionally, all power in the region flows.
Reserve margin	Reserve generating capacity maintained above the peak demand for electricity so as to provide a level of operating flexibility and reliability within the system.
Reserve trader	Market start-up function allocated to AEMO under the *National Electricity Rules* that allows it to contract for capacity where reserve margins are likely to be breached.
Residual	The difference between the actual value and the fitted (or predicted) value; there is a residual for each observation in the sample used to obtain an OLS regression line.
Residual analysis	A type of analysis that studies the sign and size of residuals for particular observations after a multiple regression model has been estimated.
Root mean squared error (RMSE)	Another name for the standard error of the regression in multiple regression analysis.
Row vector	A vector of numbers arranged as a row.
Sample average	The sum of *n* numbers divided by *n*; a measure of central tendency.
Sample correlation	For outcomes on two random variables, the sample covariance divided by the product of the sample standard deviations.

Sample correlation coefficient	An estimate of the (population) correlation coefficient from a sample of data.
Sample covariance	An unbiased estimator of the population covariance between two random variables.
Sampling distribution	The probability distribution of an estimator over all possible sample outcomes.
Seasonal dummy variables	A set of dummy variables used to denote the quarters or months of the year.
Seasonality	A feature of monthly or quarterly time series where the average value differs systematically by season of the year.
Seasonally adjusted	Monthly or quarterly time series data where some statistical procedure – possibly regression on seasonal dummy variables – has been used to remove the seasonal component.
Selected sample	A sample of data obtained not by random sampling but by selecting on the basis of some observed or unobserved characteristic.
Sent out energy	The amount of electricity supplied by a scheduled generator to the transmission or distribution network at its connection point.
Serial correlation	In a time series or panel data model, correlation between the errors in different time periods.
Short-run elasticity	The impact propensity in a distributed lag model when the dependent and independent variables are in logarithmic form.
Significance level	The probability of Type I error in hypothesis testing.
Simple Linear Regression Model	A model where the dependent variable is a linear function of a single independent variable, plus an error term.
Simultaneity	A term that means at least one explanatory variable in a multiple linear regression model is determined jointly with the dependent variable.
Skewness	A measure of how far a distribution is from being symmetric, based on the third moment of the standardised random variable.
Slope	In the equation of a line, the change in the y variable when the x variable increases by one.
Slope parameter	The coefficient on an independent variable in a multiple regression model.
Spot market	Market in which electricity is traded, establishing a price for electricity which equates supply and demand for each half-hour of the day. The electricity spot market provides a wholesale trading mechanism linking generators, retail authorities and wholesale end-use customers.
Standard deviation	A common measure of spread in the distribution of a random variable.
Standard error	Generically, an estimate of the standard deviation of an estimator.

Standard error of the regression (SER)	In multiple regression analysis, the estimate of the standard deviation of the population error, obtained as the square root of the sum of squared residuals over the degrees of freedom.
Standard normal distribution	The normal distribution with mean zero and variance one.
Static model	A time series model where only contemporaneous explanatory variables affect the dependent variable.
Stationary process	A time series process where the margins and all joint distributions are invariant across time.
Statistical significance	The importance of an estimate as measured by the size of a test statistic, usually a *t* statistic.
Steam generating plant	A generating plant in which the prime mover is a steam turbine. The steam used to drive the turbine is typically produced in a boiler where fossil fuels are burned.
Stratified sampling	A non-random sampling scheme whereby the population is first divided into several non-overlapping, exhaustive strata and then random samples are taken from within each stratum.
Structural parameters	The parameters appearing in a structural equation.
Substation	An assemblage of electrical equipment for the purposes of changing and/or regulating the voltage of electrical circuits.
Switching station	An assembly of electrical equipment for the purposes of switching high voltage electrical circuits.
System Marginal Price (SMP), (or pool price)	The wholesale price of electricity in the pool recorded half-hourly on the basis of 5-minute bids. The 5-minute price is set by the highest bid submitted by dispatched generators or customers (demand bid) during that period. This price normally applies to all market participants, regardless of their own bid.
***t* ratio**	*See t* statistic.
***t* statistic**	The statistic used to test a single hypothesis about the parameters in an econometric model.
Test statistic	A rule used for testing hypotheses where each sample outcome produces a numerical value.
Time series data	Data collected over time on one or more variables.
Time trend	A function of time that is the expected value of a trending time series process.
Transformer	A device that converts electricity from one voltage level to another.
Transmission constraints	Physical limitations of the Transmission System to carry a load under specified conditions for a given period of time.
Transmission network	Electricity power lines and associated infrastructure that convey electricity between certain generators and distribution systems.
Transmission Network Service Provider (TNSP)	An organisation which engages in the activity of owning, controlling or operating a regulated transmission system.

Transpose	For any matrix, the new matrix obtained by interchanging its rows and columns.
Two-tailed test	A test against a two-sided alternative.
Type I error	A rejection of the null hypothesis when it is true.
Type II error	The failure to reject the null hypothesis when it is false.
Unbiased estimator	An estimator whose expected value (or mean of its sampling distribution) equals the population value (regardless of the population value).
Var	The unit of reactive power. For a two-wire circuit, the product of the voltage times the current times the sine of the angular phase difference by which the voltage leads or lags the current. Vars and watts combine in a quadrature relationship to form volt-amperes.
Variance	A measure of spread in the distribution of a random variable.
Volt	A unit of measure of electric potential (pressure). It is the electromotive force which, if steadily applied to a circuit having a resistance of one ohm, will produce a current of one ampere.
Voltage	The pressure at which electricity is transferred through power lines.
Watt-hour	The total amount of energy used in one hour by a device that uses one watt of power for continuous operation. Electric energy is commonly sold by the kilowatt-hour.