IMPORTANT

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<td>24/02/2014</td>
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<td>System Operator</td>
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1. EXECUTIVE SUMMARY

The 2014 Annual Security of Supply Assessment (ASA) has been completed by the System Operator in accordance with the requirements set out in the Security of Supply Forecasting and Information Policy (SoSFIP)\(^1\). The ASA provides an assessment of the power system’s ability to meet winter energy and peak requirements over the period 2014 to 2022.

The assessment forecasts the Winter Capacity Margin and the Winter Energy Margin in accordance with the SoSFIP, and compares them with the Electricity Authority’s security of supply standards, set out in clause 7.3(2) (a) and (b) of the Code:

- A Winter Energy Margin (WEM) of 14-16% for New Zealand and 25.5-30% for the South Island
- A Winter Capacity Margin (WCM) of 630-780 MW for the North Island

The key conclusions of this report are:

- Under the base-case assumptions, the New Zealand WEM is forecast to remain above or within the security standard with just existing and committed generation until 2021. See Figure 1 on the following page.
- Under the base-case assumptions, the North Island WCM and South Island WEM are forecast to remain above or within the security standards with just existing and committed generation for the full forecast period. See Figures 2 and 3 on the following page.
- The high demand, reduced thermal generation, and reduced capacity factor sensitivity scenarios reduce existing and committed generation below the North Island WCM security standard after 2018.
- The high demand, reduced thermal generation, and low inflows sensitivity scenarios reduce existing and committed generation below the New Zealand WEM security standard after 2015, and the South Island WEM after 2018.
- There is sufficient potential capacity and energy from future generation projects to respond to continuous supply or demand trends, such as those assessed in this report.
- Unless there is a rapid change to either supply or demand, it is unlikely the New Zealand electricity system will suffer supply shortages in the medium term, even in a moderately low inflow year.
- Assessed against the security standards set by the Electricity Authority, the New Zealand electricity system is currently oversupplied in generation following recent generation investment. This was likely in part due to recent low demand growth.

Figure 1: New Zealand Winter Energy Margin 2014 to 2022 – Base-case

Figure 2: South Island Winter Energy Margin 2014 to 2022 – Base-case

Figure 3: North Island Winter Capacity Margin 2014 to 2022 – Base-case
## 2. Glossary

<table>
<thead>
<tr>
<th>Term</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASA</td>
<td>Annual Security of Supply Assessment</td>
</tr>
<tr>
<td>Capacity Security Standard</td>
<td>A WCM of 630-780 MW for the North Island</td>
</tr>
<tr>
<td>CCGT</td>
<td>Combined cycle gas turbine</td>
</tr>
<tr>
<td>EA</td>
<td>Electricity Authority</td>
</tr>
<tr>
<td>Embedded Generation Energy</td>
<td>Generation plant that is connected directly to the distribution network in which it is located; this type of plant is not modelled in the ASA.</td>
</tr>
<tr>
<td>Security Standard</td>
<td>A WEM of 14-17% for New Zealand and 25.5-30% for the South Island.</td>
</tr>
<tr>
<td>GIP</td>
<td>Grid Injection Point – where electricity enters the Transpower grid from grid connect generation.</td>
</tr>
<tr>
<td>Grid Connected Generation</td>
<td>Generation plant that is connected directly to the high voltage grid.</td>
</tr>
<tr>
<td>GXP</td>
<td>Grid Exit Point – where electricity exits the Transpower grid and enters the distribution networks.</td>
</tr>
<tr>
<td>Nameplate Capacity</td>
<td>This is the maximum capacity of individual generation equipment. This data is typically supplied by the generation companies and does not account any de-rating effects such as outages or operating constraints.</td>
</tr>
<tr>
<td>NI-WCM</td>
<td>North Island Winter Capacity Margin</td>
</tr>
<tr>
<td>NZ-WEM</td>
<td>New Zealand Winter Energy Margin</td>
</tr>
<tr>
<td>SI-WEM</td>
<td>South Island Winter Energy Margin</td>
</tr>
<tr>
<td>SoSFIP</td>
<td>The Security of Supply Information Policy</td>
</tr>
<tr>
<td>WCM</td>
<td>Winter Capacity Margin</td>
</tr>
<tr>
<td>WEM</td>
<td>Winter Energy Margin</td>
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3. **INTRODUCTION**

The annual publication of a medium to long-term security assessment is required by the Code and the SoSFIP, and is part of the System Operator’s security of supply role. A security assessment was last published by the System Operator in February 2013. This document fulfils the obligations set out in clause 7.3(2) (a) and (b) of the Code.

This assessment is intended to provide a metric in which to gauge the security of supply outlook in the medium term to enable participants to assess the risk of supply shortages, and to assist potential investment decision making.

This report assesses the Winter Energy Margin and the Winter Capacity Margin, terms defined in the SoSFIP, for the period 2014 to 2022.

3.1 **INVITATION TO COMMENT**

The System Operator welcomes feedback on this report, including any additional information for analysis that may lead to this report being updated. Comment and additional information, which if marked accordingly may be given in confidence, should be:

- Emailed to the attention of Bennet Tucker at **bennet.tucker@transpower.co.nz**
- Or a hard copy may be sent to the attention of:
  - Bennet Tucker
  - Transpower
  - PO Box 1021
  - Wellington 6140
4. **BACKGROUND**

4.1 **ASSESSMENT CONTEXT AND INTERPRETATION**

As set out in the System Operator's SoSFIP, the System Operator must prepare and publish a security of supply assessment that enables interested parties to compare projected winter energy and capacity margins over the next 5 or more years. The security standards used in this assessment were determined by the EA and are summarised below:

- 14-16% winter energy margin in New Zealand
- 25.5-30% winter energy margin in the South Island
- 630-780 MW winter capacity margin in the North Island

The EA derived the above standards using a probabilistic analysis. The analysis sought to determine:

- The efficient level of North Island peaking capacity; defined as the level that minimizes the sum of the expected societal cost of capacity shortage plus the cost of providing peaking generation capacity.
- The efficient level of national winter energy supply; defined as the level that minimizes the sum of the expected societal cost of energy shortage plus the cost of providing thermal firming capacity.
- Equivalently, the efficient level of South Island winter energy supply.

The Authority has suggested that the capacity security of supply standard should be interpreted as follows:

- A NI-WCM below the lower standard of 630 MW indicates an inefficiently low level of capacity; the cost of adding more capacity would be more than justified by the reduction in shortage costs at times of insufficient capacity.
- A NI-WCM between 630 and 780 MW indicates a roughly efficient level of capacity.
- A NI-WCM above the upper standard of 780 MW indicates a capacity level that is inefficiently high in terms of the trade-off between supply costs and the cost of shortage at times of insufficient capacity (but may still be efficient for other reasons).

The energy security of supply standards should be interpreted in a similar fashion.

The ASA only assesses New Zealand energy and capacity margins for winter. This is because at a national and island level, the New Zealand electricity system is most stressed in winter due to high demand and low inflows. Therefore, the winter energy and capacity margins are the best measure of energy and capacity risk for New Zealand. Refer to Appendix 3 for more detail.

---

4.2 **OTHER SYSTEM OPERATOR SECURITY OF SUPPLY FUNCTIONS**

The System Operator performs other security of supply related functions that are covered in the SoSFIP and the Emergency Management Policy. These include:

- Shorter-term monitoring and information provision such as the weekly reporting of hydro levels relative to the Hydro Risk Curves\(^3\).

4.3 **PREVIOUS SECURITY ASSESSMENTS**


For the assessments undertaken by the system operator from 2011, refer [http://www.systemoperator.co.nz/security-supply/annual-security-assessments](http://www.systemoperator.co.nz/security-supply/annual-security-assessments).

\(^3\) [http://www.systemoperator.co.nz/security-supply/sos-weekly-reporting](http://www.systemoperator.co.nz/security-supply/sos-weekly-reporting)
5. **INPUT ASSUMPTIONS**

5.1 **FRAMEWORK**

The input assumptions of the assessment are:

- Generation (existing and proposed new projects)
- Electricity demand (including demand response)
- Inter-island transmission capability

This assessment includes a base-case scenario and a range of sensitivity scenarios designed to test the effect of a variety of credible but less probable alternatives from the base-case. The base-case assumptions are set out in Section 5.2, and the alternative assumptions used in the sensitivity scenarios are set out in Section 5.3.

New generation development options under consideration by investors may or may not proceed for a variety of reasons. Accordingly, new generation projects have been allocated to four categories: committed, “high” probability, “medium” probability, and “low” probability. Each scenario includes four cases, with:

- Existing and committed generation only
- Existing, committed and “high” probability generation
- Existing, committed, “high” and “medium” probability generation
- Existing, committed, “high”, “medium” and “low” probability generation

All scenarios cover the period from 2014 to 2022.

The methodology for the calculation of the WEM and the WCM is covered in Sections 6.1 and 7.1.

5.2 **BASE-CASE ASSUMPTIONS**

The basis for the ASA methodology, including assumptions used in modelling, is the Electricity Authority’s Security Standards Assumptions Document (SSAD)\(^4\). The SSAD outlines the high level assumptions and formulas in which the ASA calculations are based on. This section describes many of these and other non-prescribed assumptions that are drawn from other sources. For a complete and detailed set of assumptions refer to the appendices (Sections 9 and 10).

Assumptions about generation are largely based on information received from the major Generators on a confidential basis. The System Operator thanks all contributors including; Genesis Energy, Meridian Energy, Contact Energy, Mighty River Power, TrustPower and Todd Energy for the information provided. Some publicly available information is also used.

Demand assumptions are based on a P50 view of Transpower’s Long Term Electricity Demand Forecast (LEDFM).

5.2.1 **Monitoring Input Assumptions**

It is possible that the WCM and WEM may change as a result of new information. All assumptions that inform this assessment will be reviewed and if necessary adjusted as part of the next annual assessment process due in early 2015.

5.2.2 Existing Generation Assumptions

Based on information from Genesis Energy, a second Huntly coal-fired unit is assumed to be put into long-term storage before the 2014 winter. This is in addition to the first Huntly coal-fired unit to be put into long term storage; this has been in long-term storage since December 2012. The removal of a second Huntly coal-fired unit is assumed to be committed.

All other existing generation is expected to remain operationally available throughout the assessment period (2014 – 2022), subject to normal limitations (e.g. the variability of intermittent generation, the dependence of hydro on inflows, the outage rates of thermal and hydro plants).

See Section 9 for further detail on base-case assumptions about existing generation.

5.2.3 Future Generation Assumptions

Information provided by the Generators has been aggregated for publication in order to preserve confidentiality. However, as the committed generation information is publically available, our assumptions around those projects can be freely disclosed. The only project modelled in the ASA as committed is Te Mihi, which is assumed to be commissioned in time for the 2014 winter.

Figure 4 shows the new generation data in aggregate form.
All thermal generation, with the exception of Whirinaki, is assumed to be fully fuelled. This means that thermal generation’s ability to contribute to the WEM and WCM is not constrained by fuel availability. Whirinaki is assumed to be constrained to 15 GWh year⁻¹ due to fuel supply constraints.

5.2.5 Demand Forecast Assumptions

This assessment uses the P50 Transpower Electricity Demand Forecast for its base-case scenario, produced using the 2014 Long-term Electricity Demand Forecast Model (LEDFM).

The 2014 LEDFM is lower than in previous years due to continued low peak and energy demand growth.

The use of a forecast derived from the LEDFM is consistent with both the National Winter Group Assessment (NWG) and the System Security Forecast (SSF), and fulfils the Electricity Authority’s requirements around demand in the ASA (Section 4 of the SSAD).
The demand forecast is net of all embedded generation; in other words, demand is net demand at the GXP and converted to demand for generation at the GIPs by adding on transmission losses. This is consistent with the 2013 ASA. Figure 5 shows expected demand out to 2022 (inclusive of losses):

The average growth rate in the base-case is approximately 1.1% p.a. for the period 2014 to 2022.

The average growth rates for the low and high scenarios are 0.1% and 2.1% p.a. respectively. These sensitivities explore the effect of higher and lower than expected demand, but do not encompass the full range of uncertainty in the 2014 LEDFM forecast; future demand may be higher or lower than the range explored here.

See Section 10 for more detailed assumptions about the electricity demand forecast used in the base-case scenario.

*Figure 5: Expected demand – both Peak and Energy (net GXP + transmission losses)*
5.2.6 Inter-island Transmission Assumptions

The assessment of the WEMs and the NI-WCM does not incorporate detailed modelling of transmission. However, there are assumptions made about the amount of energy that can be transferred from the North Island to the South Island during winter and the capacity that can be transferred from the South Island to the North Island during periods of peak demand.

See Section 9 for detailed assumptions about inter-island transmission.

5.3 Scenarios

The sensitivity of the WEMs and the NI-WCM to a number of scenarios are included in the ASA modelling. This section describes the scenarios that are included in this assessment.

Note that the outcomes described are not necessarily mutually exclusive and some scenarios may be coupled – for example, it is likely that planned generation would be deferred if Tiwai significantly reduces its load or shuts down. However, the scope of this study has been limited to assessing each scenario individually.
Table 1: Sensitivity scenarios

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Affects Energy</th>
<th>Affects Capacity</th>
<th>Rationale</th>
<th>Assumptions Made</th>
</tr>
</thead>
<tbody>
<tr>
<td>High demand</td>
<td>Y</td>
<td>Y</td>
<td>Demand may exceed the base-case forecast.</td>
<td>+1% demand growth p.a. on base-case.</td>
</tr>
<tr>
<td>Low demand</td>
<td>Y</td>
<td>Y</td>
<td>Demand may fall below the base-case forecast.</td>
<td>-1% demand growth p.a. on base-case.</td>
</tr>
<tr>
<td>Delayed Builds</td>
<td>Y</td>
<td>Y</td>
<td>Generation investment may be postponed due to market conditions.</td>
<td>Projects, other than committed, are uniformly delayed by 1 year if they are originally assumed to be built prior to 2017, and delayed by 2 years for those projects built after or during 2017.</td>
</tr>
<tr>
<td>Low inflows</td>
<td>Y</td>
<td>N</td>
<td>This scenario explores the sensitivity of the WEMs to hydro inflow assumptions.</td>
<td>In the calculation of energy margins, inflows and initial hydro storage are reduced by 10% (equivalent to about the 20th percentile of historical hydro inflows).</td>
</tr>
<tr>
<td>Reduced thermal generation</td>
<td>Y</td>
<td>Y</td>
<td>It is possible that thermal generation may be limited by a number of factors in the future. This could result in the decommissioning of existing thermal generation and a halt in new thermal generation commissioning.</td>
<td>One CCGT is decommissioned and no new thermal generation is commissioned.</td>
</tr>
<tr>
<td>Reduced capacity factors</td>
<td>N</td>
<td>Y</td>
<td>Capacity factors may be lower than assumed.</td>
<td>All capacity factors are reduced by 5%.</td>
</tr>
<tr>
<td>Limited south transfer</td>
<td>Y</td>
<td>N</td>
<td>The base-case assumption is that southward transfer can rise to an average of over 480 MW – but, as noted in the Winter Review, various factors can combine to prevent this. During June-August 2008, the average net southward transfer over the HVDC link was approximately 300 MW. Although this limit may no longer be relevant due to the commissioning of Pole 3, this scenario is still considered to be meaningful as it illustrates the sensitivity of the SI-WEM to HVDC transfer limits.</td>
<td>Inter-island transfer is limited to 1,314 GWh in the SI-WEM (equivalent to an average of 300 MW).</td>
</tr>
<tr>
<td>Tiwai shutdown</td>
<td>Y</td>
<td>Y</td>
<td>Tiwai aluminium smelter may reduce its output or shutdown due to economic conditions.</td>
<td>The base-case assumption is that Tiwai’s load remains at current levels. There are two scenarios in which Tiwai reduces its load: 1. Tiwai reduces its average load to 400 MW from 2017. 2. Tiwai reduces its load in stages beginning 2015, until it shuts down in 2017.</td>
</tr>
</tbody>
</table>

6. Energy Margin Assessment

6.1 Methodology

The assessment of Energy Margins follows the methodology set out in the SSAD. There are two metrics:

The New Zealand Winter Energy Margin:

\[ \text{NZ-WEM} = \left( \frac{\text{national expected available energy}}{\text{national expected demand for energy}} - 1 \right) \times 100\% \]

The South Island Winter Energy Margin:

\[ \text{SI-WEM} = \left( \frac{\text{south island expected available energy} + \text{expected HVDC transfers south}}{\text{south island expected demand for energy}} - 1 \right) \times 100\% \]

Components to these equations are described in Table 2 and Table 3, below.

Table 2: Summarising the NZ-WEM components

<table>
<thead>
<tr>
<th>Component</th>
<th>Comprises</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected Supply Capability (GWh)</td>
<td>Thermal GWh</td>
<td>Maximum expected thermal generation available to meet winter (1 April to 30 September) energy demand allowing for forced and scheduled outages, available fuel supply and transmission constraints.</td>
</tr>
<tr>
<td></td>
<td>Median Hydro GWh</td>
<td>Expected winter (1 April to 30 September) hydro generation based on median inflows and expected 1 April start storage of 2,750 GWh.</td>
</tr>
<tr>
<td></td>
<td>Other GWh</td>
<td>Expected winter (1 April to 30 September) energy available from geothermal and wind generation based on long-run average supply.</td>
</tr>
<tr>
<td>Expected Demand (GWh)</td>
<td>N/a</td>
<td>Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).</td>
</tr>
</tbody>
</table>

Table 3: Summarising the SI-WEM components

<table>
<thead>
<tr>
<th>Component</th>
<th>Comprises</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected Supply Capability (GWh)</td>
<td>HVDC GWh</td>
<td>Expected winter (1 April to 30 September) HVDC transfers received in the South Island.</td>
</tr>
<tr>
<td></td>
<td>Median Hydro GWh</td>
<td>Expected winter (1 April to 30 September) hydro generation based on median inflows and expected 1 April start storage of 2,400 GWh.</td>
</tr>
<tr>
<td></td>
<td>Wind GWh</td>
<td>Expected winter (1 April to 30 September) wind generation based on long-run average supply.</td>
</tr>
<tr>
<td>Expected Demand (GWh)</td>
<td>N/a</td>
<td>Expected winter demand, allowing for the normal demand response to periods of high spot prices (excluding any response due to savings campaigns or forced rationing).</td>
</tr>
</tbody>
</table>
6.2 **Energy Margin Results**

This section summarises the results of the WEM assessment, based on the input assumptions summarised in Section 5 and described in detail in Appendices 1 and 2.

Forecasts of the NZ-WEM and SI-WEM from 2014 – 2022 under the base-case scenario are shown in Figure 6 and Figure 7. Sensitivity results are presented following the base-case results.

Energy margin results:

- In the base-case scenario, the SI-WEM is forecast to remain above the upper limit of the security standard for the full forecast period with just existing and committed generation.
- In the base-case scenario, the NZ-WEM is forecast to remain above or within the security standard with just existing and committed generation until 2021.
- In all scenarios, existing and committed generation are enough to keep the NZ and SI WEMs above or within their respective security standard until at least 2015 and 2018 respectively.
- The high demand, low inflows, and reduced thermal generation scenarios significantly reduce the WEMs compared to the base-case.
- Under all scenarios, the SI-WEM is significantly higher than the NZ-WEM, compared to their respective security standard.
- In all scenarios, generation with a medium likelihood of construction is enough to keep the NZ and SI WEMs above or within the security standards for the full forecast period.
- The WEMs are particularly sensitive to the high demand scenario. However, there are sufficient generation options to keep both the WEMs above the security standards in the forecast period.
- In the event of a Tiwai shutdown, it would take several years for both the NZ and SI WEMs to return to pre-shutdown levels.
- There are no scenarios in which the WEMs fall below zero in the forecast period.
- Under the low demand scenario, the NZ-WEM is forecast to remain at an approximately constant level with just existing and committed generation, and the SI-WEM is forecast to increase with just existing and committed generation.
- The 2014 WEMs are higher than in the 2013 ASA. On average, the base-case 2014 NI-WEM is 2% higher and the 2014 SI-WEM is 17% higher than the base-case scenario in the 2013 ASA. This is predominantly due to the lower demand forecast used in this ASA.
Figure 6: New Zealand Winter Energy Margin 2014 to 2022 – Base-case

Figure 7: South Island Winter Energy Margin 2014 to 2022 – Base-case

Figure 8: New Zealand Winter Energy Margin 2014 to 2022 – High Demand Scenario
Figure 9: South Island Winter Energy Margin 2014 to 2022 – High Demand Scenario

Figure 10: New Zealand Winter Energy Margin 2014 to 2022 – Low Demand Scenario

Figure 11: South Island Winter Energy Margin 2014 to 2022 – Low Demand Scenario
Figure 12: New Zealand Winter Energy Margin 2014 to 2022 – Delayed Build Scenario

Figure 13: South Island Winter Energy Margin 2014 to 2022 – Delayed Build Scenario

Figure 14: New Zealand Winter Energy Margin 2014 to 2022 – Low Inflows Scenario
Figure 15: South Island Winter Energy Margin 2014 to 2022 – Low Inflows Scenario

Figure 16: New Zealand Winter Energy Margin 2014 to 2022 – Reduced Thermal Generation Scenario

Figure 17: South Island Winter Energy Margin 2014 to 2022 – Reduced Thermal Generation Scenario
Figure 18: South Island Winter Energy Margin 2014 to 2022 – Limited South Transfer Scenario

Figure 19: New Zealand Winter Energy Margin 2014 to 2022 – Tiwai Shutdown Scenario 1

Figure 20: South Island Winter Energy Margin 2014 to 2022 – Tiwai Shutdown Scenario 1
Figure 21: New Zealand Winter Energy Margin 2014 to 2022 – Tiwai Shutdown Scenario 2

Figure 22: South Island Winter Energy Margin 2014 to 2022 – Tiwai Shutdown Scenario 2
7. **Capacity Margin Assessment**

7.1 **Methodology**

The assessment of Winter Capacity Margin follows the methodology set out in the SSAD. There is a single metric; the North Island Winter Capacity Margin:

\[
NI-WCM = \text{North Island expected available capacity} - \text{North Island expected demand} + \text{expected HVDC transfer north (function of SI capacity - SI demand)}
\]

The input factors that comprise the WCM calculation are summarised in Table 4, below:

*Table 4: Summarising the North Island Winter Capacity Margin (WCM) Components*

<table>
<thead>
<tr>
<th>Component</th>
<th>Comprises</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Expected NI Supply Capacity (MW)</td>
<td>NI Thermal MW</td>
<td>Installed capacity of North Island thermal generation sources allowing for forced and scheduled outages.</td>
</tr>
<tr>
<td></td>
<td>NI Hydro MW</td>
<td>Installed capacity of North Island controllable hydro schemes allowing for forced and scheduled outages and de-rated to account for energy and other constraints which affect output during peak times.</td>
</tr>
<tr>
<td></td>
<td>NI Other MW</td>
<td>Expected winter daytime (1 April – 31 October between 7am and 10pm) generation available from geothermal, wind and uncontrolled hydro scheme generation.</td>
</tr>
<tr>
<td></td>
<td>NI Demand Response and Interruptible Load MW</td>
<td>Expected demand response and interruptible load over the highest 200 half hours of demand in winter (1 April – 31 October between 7am and 10pm).</td>
</tr>
<tr>
<td>Less Expected NI H100 Demand (MW)</td>
<td>N/a</td>
<td>Expected average of the highest 200 half hours (or 100 hours) of demand in winter, plus losses. This is referred to as H100 NI demand.</td>
</tr>
<tr>
<td>SI Capacity Contribution</td>
<td>South Island MW</td>
<td>The net amount of MW the South Island can provide the North Island during peak periods. This is a similar calculation to above (supply capacity minus H100 NI demand); however, also takes into account HVDC transfer capability.</td>
</tr>
</tbody>
</table>
7.2 CapacitY Margin Results

This section summarises the results of the NI-WCM assessment, based on the input assumptions summarised in Section 5 and described in detail in Appendices 1 and 2.

The forecast of the NI-WCM from 2014 – 2022 under the base-case scenario is shown in Figure 23. Sensitivity results are presented following the base-case results.

Capacity margin results:

- In the base-case scenario, the NI-WCM is forecast to stay above or within the security standard for the full forecast period with just existing and committed generation.
- In all scenarios, existing and committed generation are enough to keep the NI-WCM above or within the security standard until at least 2018.
- The scenarios that reduce existing and committed generation below the lower limit of the security standard during the forecast period are the high demand, reduced thermal generation, and reduced capacity factor scenarios.
- These three scenarios require generation with a medium likelihood of construction to keep them above or within the security standard for the full forecast period.
- The reduced thermal generation scenario is notable in reducing the NI-WCM, including generation with only a low likelihood of construction, to its lowest level. The NI-WCM drops as low as 824 MW in 2017, rising to 1328 MW in 2021.
- A Tiwai shutdown has less of an effect on the NI-WCM than the WEMs. It would take only about a year for the WCM to return to pre-shutdown levels.
- There are no scenarios for which the NI-WCM becomes negative in the forecast period.
- Under the low demand scenario, the NI-WCM remains at an approximately constant level with just existing and committed generation.
- The 2014 NI-WCM is significantly higher than in the 2013 ASA. On average, the base-case 2014 NI-WCM is 48% higher than the base-case scenario in the 2013 ASA. This is predominantly due to the lower demand forecast used in this ASA.
Figure 23: North Island Winter Capacity Margin 2014 to 2022 – Base-case

Figure 24: North Island Winter Capacity Margin 2014 to 2022 – High Demand Scenario

Figure 25: North Island Winter Capacity Margin 2014 to 2022 – Low Demand Scenario
Figure 26: North Island Winter Capacity Margin 2014 to 2022 – Delayed Build Scenario

Figure 27: North Island Winter Capacity Margin 2014 to 2022 – Reduced Thermal Generation Scenario

Figure 28: North Island Winter Capacity Margin 2014 to 2022 – Reduced Capacity Factors Scenario
Figure 29: North Island Winter Capacity Margin 2014 to 2022 – Tiwai Shutdown Scenario 1

Figure 30: North Island Winter Capacity Margin 2014 to 2022 – Tiwai Shutdown Scenario 2
8. **CONCLUSIONS**

8.1 **ENERGY MARGIN SECURITY**

The NZ-WEM is forecast to remain above or within the security standard until 2021 without any new generation. The SI-WEM is forecast to remain above the security standard for the full forecast period (2014 – 2022) without any new generation.

Therefore, it is unlikely New Zealand will suffer major energy supply shortages in the medium term, even in a moderately low inflow year.

However, there are two possible scenarios that could reduce energy security including:

- High demand growth
- Reduced thermal generation

These scenarios are significant departures from the base-case assumptions and it is not surprising energy security is reduced. However, in all cases the WEMs do not fall below the security standards until 2016 at the earliest, and never fall below zero.

A change from the base-case scenario such as from these scenarios is likely to be signaled in advance of the requirement for any new generation. In addition, there are enough potential generation options to keep the WEMs within the security standards if these scenarios eventuate.

Therefore, these scenarios, or other continuous supply or demand trends of a similar magnitude, do not pose a major supply risk.

Despite this, the most likely energy supply risk for New Zealand is low hydro inflows. As explored in the low inflows sensitivity, the New Zealand electricity system is not at a high risk of shortages during a moderately low inflow year (10% lower than median). However, there is always the possibility an exceptionally low inflow year may result in energy supply shortages.

8.2 **CAPACITY MARGIN SECURITY**

The NI-WCM is forecast to remain above or within the security standard for the full forecast period (2014 – 2022), without any new generation.

Therefore, it is unlikely the North Island (or New Zealand) will suffer major capacity supply shortages in the medium term.

However, there are several possible scenarios that could reduce capacity security including:

- High demand growth
- Reduced thermal generation
- Reduced capacity factors

Similarly to energy security, there are sufficient potential generation options to keep the NI-WCM within the security standard if these scenarios or other continuous supply or demand trends of a similar magnitude eventuate.

Note; this conclusion does not exclude the possibility of short term, regional, capacity shortages due to transmission constraints, generation outages or other unplanned events. These events are outside of the scope of the ASA, which assesses security in the medium term.
8.3 **INTERPRETATION OF THE MARGINS AGAINST THE STANDARDS**

The NZ-WEM, SI-WEM and NI-WCM are forecast to remain above or within the efficient level (as determined by the Electricity Authority) in the base-case until 2021. This suggests the New Zealand electricity system is currently in a period of oversupply.

This oversupply is likely a result of the lower than expected demand since about 2007. As generation projects are planned and constructed over several years, the need for additional generation has to be assessed against a forecast of demand. Demand forecast are inherently uncertain, and the downturn in demand has appeared to have resulted in some surplus generation investment in the short term.

It should be noted that the number of potential new generation projects and the probability of construction has dropped from last year’s ASA, assessed over the same time period (see Figure 31). In addition, the decommissioning or long term storage of under-utilized plant, for example a second Huntly coal-fired unit, has been brought forward. This is typical behavior from a competitive market that is oversupplied with generation, and indicates participants are responding to low demand.

![Figure 31: New Generation – 2014 ASA compared with 2013 ASA](image-url)
9. **Appendix 1: Detailed Supply Assumptions in the Base-case Scenario**

9.1 **Introduction**

This appendix sets out the key supply assumptions used in the energy and capacity margin assessments. Many of the assumptions discussed are based on the Security Standards Assumptions Document (SSAD) published by the Electricity Authority\(^6\).

The focus is on grid-connected generation. As explained in Appendix 2, embedded generation is netted off the demand forecasts used for this assessment, and should not be modelled on the supply side.

9.2 **Existing Supply**

The following tables summarise the existing supply that is used in the model, based on the assumptions in Section 9.4.

<table>
<thead>
<tr>
<th>Scheme</th>
<th>Type</th>
<th>MW</th>
<th>Assumed Contribution to Energy Margin's (potential GWh over April - Sep)</th>
<th>Assumed Contribution to Capacity Margins (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntly Coal-Fired Units</td>
<td>Thermal</td>
<td>486</td>
<td>1,683</td>
<td>471</td>
</tr>
<tr>
<td>Huntly Unit 5</td>
<td>Thermal</td>
<td>385</td>
<td>1,595</td>
<td>373</td>
</tr>
<tr>
<td>Huntly Unit 6</td>
<td>Thermal</td>
<td>48</td>
<td>199</td>
<td>47</td>
</tr>
<tr>
<td>Kawerau</td>
<td>Geothermal</td>
<td>100</td>
<td>386</td>
<td>90</td>
</tr>
<tr>
<td>Mangahao</td>
<td>Hydro - RoR</td>
<td>42</td>
<td>68</td>
<td>21</td>
</tr>
<tr>
<td>Matahina</td>
<td>Hydro - RoR</td>
<td>80</td>
<td>135</td>
<td>40</td>
</tr>
<tr>
<td>McKee</td>
<td>Thermal</td>
<td>102</td>
<td>423</td>
<td>99</td>
</tr>
<tr>
<td>Mokai</td>
<td>Geothermal</td>
<td>112</td>
<td>444</td>
<td>100</td>
</tr>
<tr>
<td>Nga Awa Purua</td>
<td>Geothermal</td>
<td>138</td>
<td>582</td>
<td>124</td>
</tr>
<tr>
<td>Ngatamariki</td>
<td>Geothermal</td>
<td>82</td>
<td>347</td>
<td>74</td>
</tr>
<tr>
<td>Ohaaki</td>
<td>Geothermal</td>
<td>40</td>
<td>166</td>
<td>36</td>
</tr>
<tr>
<td>Otahuhu B</td>
<td>Thermal</td>
<td>400</td>
<td>1,657</td>
<td>388</td>
</tr>
<tr>
<td>Patea</td>
<td>Hydro</td>
<td>31.5</td>
<td>56</td>
<td>26</td>
</tr>
<tr>
<td>Pohihi</td>
<td>Geothermal</td>
<td>55</td>
<td>210</td>
<td>49</td>
</tr>
<tr>
<td>Rangipo</td>
<td>Hydro - RoR</td>
<td>120</td>
<td>311 + Start Storage</td>
<td>60</td>
</tr>
<tr>
<td>Southdown</td>
<td>Thermal</td>
<td>175</td>
<td>725</td>
<td>170</td>
</tr>
<tr>
<td>Stratford Peaker</td>
<td>Thermal</td>
<td>200</td>
<td>829</td>
<td>194</td>
</tr>
<tr>
<td>Tararu III</td>
<td>Wind</td>
<td>93</td>
<td>175</td>
<td>19</td>
</tr>
<tr>
<td>TCC</td>
<td>Thermal</td>
<td>377</td>
<td>1,562</td>
<td>366</td>
</tr>
<tr>
<td>Te Āpiti</td>
<td>Wind</td>
<td>91</td>
<td>151</td>
<td>18</td>
</tr>
<tr>
<td>Tokaanu</td>
<td>Hydro</td>
<td>240</td>
<td>375 + Start Storage</td>
<td>216</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Scheme</th>
<th>Type</th>
<th>MW</th>
<th>Assumed Contribution to Energy Margin’s (potential GWh over April - Sep)</th>
<th>Assumed Contribution to Capacity Margins (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Waikaremoana</td>
<td>Hydro</td>
<td>138</td>
<td>290 + Start Storage</td>
<td>135</td>
</tr>
<tr>
<td>Waikato</td>
<td>Hydro</td>
<td>1044</td>
<td>2,281 + Start Storage</td>
<td>1,023</td>
</tr>
<tr>
<td>Wairakei incl. binary</td>
<td>Geothermal</td>
<td>172</td>
<td>722</td>
<td>154</td>
</tr>
<tr>
<td>West Wind</td>
<td>Wind</td>
<td>142</td>
<td>243</td>
<td>28</td>
</tr>
<tr>
<td>Wheao</td>
<td>Hydro - RoR</td>
<td>26</td>
<td>57</td>
<td>13</td>
</tr>
<tr>
<td>Whirinaki</td>
<td>Thermal</td>
<td>155</td>
<td>7</td>
<td>150</td>
</tr>
</tbody>
</table>

* As discussed in Section 9.4.4, a total of two Huntly coal-fired units are assumed to be in long term storage from December 2013 and do not contribute to the NI-WCM or WEMs.

**Table 6: Existing South Island supply**

<table>
<thead>
<tr>
<th>Scheme</th>
<th>Type</th>
<th>MW</th>
<th>Assumed Contribution to Energy Margin’s (potential GWh over April - Sep)</th>
<th>Assumed Contribution to Capacity Margins (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Branch</td>
<td>Hydro - RoR</td>
<td>11</td>
<td>27</td>
<td>6</td>
</tr>
<tr>
<td>Clutha</td>
<td>Hydro</td>
<td>680</td>
<td>1,366</td>
<td>666</td>
</tr>
<tr>
<td>Cobb</td>
<td>Hydro</td>
<td>32</td>
<td>100</td>
<td>31</td>
</tr>
<tr>
<td>Coleridge</td>
<td>Hydro</td>
<td>40</td>
<td>143</td>
<td>39</td>
</tr>
<tr>
<td>Manapouri</td>
<td>Hydro</td>
<td>800</td>
<td>2,565</td>
<td>784</td>
</tr>
<tr>
<td>Waitaki</td>
<td>Hydro</td>
<td>1718</td>
<td>2,691</td>
<td>1,684</td>
</tr>
</tbody>
</table>

### 9.3 New Supply

The tables below list the aggregated quantities of new generation that is added to the system. This is the supporting data for Figure 1.

**Table 7: New Generation Aggregated by Year**

<table>
<thead>
<tr>
<th>Year</th>
<th>Nameplate MW</th>
<th>Assumed Contribution to Energy Margin’s (potential GWh over April - Sep)</th>
<th>Assumed Contribution to Capacity Margins (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>114</td>
<td>459</td>
<td>102</td>
</tr>
<tr>
<td>2015</td>
<td>564</td>
<td>1,919</td>
<td>421</td>
</tr>
<tr>
<td>2016</td>
<td>596</td>
<td>1,193</td>
<td>196</td>
</tr>
<tr>
<td>2017</td>
<td>315</td>
<td>1,305</td>
<td>306</td>
</tr>
<tr>
<td>2018</td>
<td>887</td>
<td>3,328</td>
<td>799</td>
</tr>
<tr>
<td>2019</td>
<td>450</td>
<td>1,041</td>
<td>153</td>
</tr>
<tr>
<td>2020</td>
<td>1,228</td>
<td>2,762</td>
<td>451</td>
</tr>
<tr>
<td>2021</td>
<td>80</td>
<td>322</td>
<td>72</td>
</tr>
<tr>
<td>2022</td>
<td>123</td>
<td>206</td>
<td>25</td>
</tr>
</tbody>
</table>
### Table 8: New Generation Aggregated by Type

<table>
<thead>
<tr>
<th>Type</th>
<th>Nameplate MW</th>
<th>Assumed Contribution to Energy Margin’s (potential GWh over April - Sep)</th>
<th>Assumed Contribution to Capacity Margins (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>2,381</td>
<td>4,006</td>
<td>476</td>
</tr>
<tr>
<td>Geothermal</td>
<td>599</td>
<td>2,407</td>
<td>537</td>
</tr>
<tr>
<td>Hydro</td>
<td>147</td>
<td>426</td>
<td>144</td>
</tr>
<tr>
<td>Thermal</td>
<td>1,455</td>
<td>6,029</td>
<td>1,411</td>
</tr>
</tbody>
</table>

### Table 9: New Generation Aggregated by Probability

<table>
<thead>
<tr>
<th>Probability</th>
<th>Nameplate MW</th>
<th>Assumed Contribution to Energy Margin’s (potential GWh over April - Sep)</th>
<th>Assumed Contribution to Capacity Margins (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Committed</td>
<td>114</td>
<td>459</td>
<td>102</td>
</tr>
<tr>
<td>High</td>
<td>250</td>
<td>1,007</td>
<td>224</td>
</tr>
<tr>
<td>Medium</td>
<td>1,434</td>
<td>3,621</td>
<td>671</td>
</tr>
<tr>
<td>Low</td>
<td>2,784</td>
<td>7,780</td>
<td>1,571</td>
</tr>
</tbody>
</table>

### Table 10: New Generation Aggregated by Island

<table>
<thead>
<tr>
<th>By Island</th>
<th>Nameplate MW</th>
<th>Assumed Contribution to Energy Margin’s (potential GWh over April - Sep)</th>
<th>Assumed Contribution to Capacity Margins (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NI</td>
<td>3,703</td>
<td>11,324</td>
<td>2,278</td>
</tr>
<tr>
<td>SI</td>
<td>879</td>
<td>1,543</td>
<td>290</td>
</tr>
</tbody>
</table>

### 9.4 Other Key Assumptions for Generation

#### 9.4.1 Outage Modelling and De-ratings

In order to allow for forced and scheduled outages the following assumptions are made in the calculation of the NZ-WEM, SI-WEM and NI-WCM:

- For thermal generation, other than the coal fired Huntly units, a de-rating of 5.4% is applied to the nameplate capacity when calculating the NZ-WEM and SI-WEM.
- For the coal-fired Huntly units a de-rating of 6.7% is applied to the nameplate capacity when calculating the NZ-WEM and SI-WEM.
- The NZ-WEM and SI-WEM have been reduced by 303 GWh in the North Island to reflect spinning reserve and frequency keeping requirements.
- For all thermal generation a de-rating of 3% is applied to the nameplate capacity when calculating the NI-WCM.
- For all controllable hydro generation a de-rating of 2% is applied to the nameplate capacity when calculating the NI-WCM.
In addition to this 2% de-rating, the following further de-ratings are applied to certain hydro generation in order to account for limited short term storage ability (Patea and Tokaanu) and chronological flow constraints on peaking ability (Waikato):

- Patea de-rated by 5 MW for the NI-WCM
- Tokaanu de-rated by 20 MW for the NI-WCM
- The Waikato hydro scheme de-rated by 60 MW for the NI-WCM

The Wheao, Matahina, Branch, Rangipo and Mangahao stations are all treated as run-of-river and assumed to contribute 50% of nameplate capacity to the NI-WCM (see Section 9.4.1.1).

- All geothermal generation is assumed to contribute 87% of nameplate capacity to the NI-WCM (see Section 9.4.1.1).
- All wind generation is assumed to contribute 20% of nameplate capacity to the NI-WCM (see Section 9.4.1.1).

### 9.4.1.1 Wind, Run-of-River Hydro, and Geothermal Capacity Factors

In the calculation of the NI-WCM it was recommended by the Electricity Authority that the wind capacity contribution be in the range of 20-25% of nameplate capacity.

Due to the conservative nature of the ASA and the relative unknowns of how wind capacity contribution will evolve as more wind is added to the New Zealand system, this assessment uses a wind capacity contribution of 20%.

The capacity contribution of run-of-river hydro and geothermal generation at the winter peak has been determined by direct comparison with wind generation, in order to de-rate the nameplate capacity of these generation types on the same basis.

From 2010, the output at 6pm each day during winter (1st April – 31st October) of each modelled plant for each generation type was summed and divided by total nameplate capacity. This was then sorted to determine the distribution of capacity factors for each generation type over this period. Figure 32 shows the percentage of time the capacity factor of each generation type is greater than the corresponding level, based on this data.
Figure 32: Capacity factor duration curves for wind, run-of-river hydro, and geothermal plant during winter 2010 - 2013.

The three wind farms modelled in the NI-WCM contributed greater than 20% of their nameplate capacity for 75% of the peak periods analyzed. Run-of-river hydro stations and geothermal plants contributed greater than 50% and 90% of their nameplate capacity for 75% of these peak periods respectively. These values are used to de-rate nameplate capacity in the NI-WCM.

9.4.2 Thermal Fuel Assumptions

All thermal generation, with the exception of Whirinaki, is assumed to be fully fuelled. This means that thermal generation’s ability to contribute to the WEM and WCM is not constrained by fuel availability. Whirinaki is assumed to be constrained to 15 GWh year\(^{-1}\) due to fuel supply constraints.

9.4.3 Start Storage

In the calculation of the WEMs an amount of freely usable energy (GWh) is assumed. This is to account for the start storage levels in the hydro catchments:

- For the calculation of the NZ-WEM the start storage level is 2750 GWh.
- For the calculation of the SI-WEM the start storage level is 2400 GWh.

9.4.4 Huntly Units Long-term Storage

It is assumed that a second Huntly coal-fired unit will be placed into long-term storage as scheduled in December of 2013. This means that only two of Huntly’s coal fired units contribute to the NI-WCM and NZ-WEM.

9.5 Transmission

Inter-island transmission assumptions are required for the assessments of the SI-WEM and the NI-WCM. North Island energy supply can meet some of the South Island’s energy demand in the assessment of the SI-WEM; similarly, South Island’s capacity can meet some of the North Island’s demand in the assessment of the NI-WCM.
The base-case assumption of this assessment is that the HVDC capability will be the combined capability of Pole 2 and Pole 3.

In addition to the modelling of the HVDC, the ASA also makes some assumptions around AC losses in order to convert GXP demand into GIP demand.

### 9.5.1 HVDC: Southwards Flow

It is assumed that the North Island will be able to supply the South Island with 2102 GWh (480 MW average transfer) of energy during the winter period. Note that this energy transfer is dependent on the North Island having the required surplus energy available. To allow for this restriction the lesser value of 2102 GWh or the net NI energy surplus (determined in the same way as the SI-WEM) is used.

It should be noted that actual southward transfer during June-August 2008 dry year was less than that assumed above. The Winter Review\(^7\) discusses some of the reasons for this. This assessment includes a scenario with considerably less southward transfer (300 MW cf. 480 MW).

Note; this limit may no longer be relevant after the commissioning of Pole 3. Despite this, the scenario is meaningful as it illustrates the sensitivity of the SI-WEM to HVDC transfer limits.

### 9.5.2 HVDC: Northwards Flow

It is assumed that during winter the South Island has the potential to supply the North Island with capacity. This is only used in the calculation of the NI-WCM.

The contribution of South Island capacity to meeting North Island demand is a function of the surplus capacity available in the South Island (determined in the same way the NI-WCM). The function used in this process was derived using simulation analysis, taking account of:

- HVDC capacity
- Transmission losses
- North Island instantaneous reserve requirements
- The low probability of forced outages on the HVDC link

This assessment assumes that both Pole 2 and Pole 3 are available at all times, and in all scenarios.

---

Figure 33: Relationship between South Island surplus and its contribution to the NI-WCM

9.5.3 AC Transmission Assumptions

This assessment does not explicitly model AC transmission constraints. The implicit assumption is that AC constraints will not systematically reduce inter-island transfers below the limits specified above.

However, AC loss assumptions are used to convert demand at the GXP level to demand for generation. These losses are detailed in Section 10.3.2.
10. **APPENDIX 2: DETAILED DEMAND FORECAST ASSUMPTIONS IN THE BASE-CASE SCENARIO**

10.1 **INTRODUCTION**

This appendix sets out the key demand assumptions used in the energy and capacity margin assessments.

This assessment bases its demand forecast on Transpower’s Long-term Electricity Demand Forecast Model 2014 (LEDFM). Note the 2014 LEDFM has not been publically released at the time of writing, and does not include an energy demand forecast.

Despite the absence of an energy demand forecast, the 2014 peak demand forecast was chosen over the 2013 demand forecast as it is significantly lower, and is considered to be a better reflection of the low demand growth since about 2007.

The 2014 energy demand forecast was produced by assuming energy demand grows at the same rate as peak demand. This implies the relationship between peak demand and energy demand will not change over time, which is not necessarily true. However, the System Operator considers it preferential to forecast energy demand in this way, rather than using the 2013 LEDFM energy demand forecast which likely overstates energy demand growth[^8].

10.2 **TREATMENT OF Generation**

The LEDFM forecast predicts demand at GXP level, with all embedded generation netted off. This approach was employed as it is how the LEDFM treats demand without modification, so all assumptions that are made in the LEDFM can be carried over to the ASA.

10.3 **SPECIFIC DEMAND ASSUMPTIONS**

For the energy margin calculations, this forecast is adjusted by:

- Allowing for transmission losses
- Allowing for demand response

Similarly for capacity margin calculations the forecast is adjusted by:

- Allowing for transmission losses
- Allowing for demand response
- Converting from single highest peak demand to H100 peak demand

In addition, winter demand (1st April – 30th September) is assumed to be 52.0% of national annual demand, and 51.5% of South Island annual demand.

10.3.1 **Demand Response**

Energy demand forecasts have been reduced by 2% to allow for voluntary demand response.

[^8]: The ASA may be updated to include an updated energy demand forecast if it becomes available.
This includes voluntary demand response resulting from high spot prices or retailer pricing initiatives, but excludes reductions in demand as a result of savings campaigns or calls for conservation.

Additionally peak demand projections in the North Island have been reduced by 176 MW to account for demand response at peak times.

### 10.3.2 Transmission Losses

Energy demand forecasts are adjusted to allow for average AC transmission losses of 3.5% (New Zealand) or 4.5% (South Island).

Peak demand forecasts are adjusted to allow for AC transmission losses of 2.88% (North Island) or 4.88% (South Island) for peak forecasting.

DC losses are incorporated in the assumptions about HVDC transfers.

### 10.3.3 H100 Demand

THE LEDFM forecast models the single highest half-hourly demand in a year. For the ASA, the Electricity Authority recommends use of the H100 demand, which is an average of the 100 highest hours (or 200 half hours) of demand falling between 7am and 10pm, 1st of April and 31st of October.

The peak demand from the LEDFM was converted to H100 peak demand using a ratio based on historical data.

### 10.4 Demand Data

The base-case energy demand is shown in Table 11.

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>New Zealand Demand (GWh)</th>
<th>North Island Demand (GWh)</th>
<th>South Island Demand (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>39,287</td>
<td>24,142</td>
<td>15,145</td>
</tr>
<tr>
<td>2011</td>
<td>38,699</td>
<td>24,128</td>
<td>14,571</td>
</tr>
<tr>
<td>2012</td>
<td>38,053</td>
<td>23,818</td>
<td>14,236</td>
</tr>
<tr>
<td>2013</td>
<td>40,069</td>
<td>25,442</td>
<td>14,627</td>
</tr>
<tr>
<td>2014</td>
<td>40,596</td>
<td>25,838</td>
<td>14,758</td>
</tr>
<tr>
<td>2015</td>
<td>41,020</td>
<td>26,170</td>
<td>14,850</td>
</tr>
<tr>
<td>2016</td>
<td>41,493</td>
<td>26,538</td>
<td>14,955</td>
</tr>
<tr>
<td>2017</td>
<td>41,936</td>
<td>26,883</td>
<td>15,054</td>
</tr>
<tr>
<td>2018</td>
<td>42,395</td>
<td>27,176</td>
<td>15,219</td>
</tr>
<tr>
<td>2019</td>
<td>42,856</td>
<td>27,517</td>
<td>15,339</td>
</tr>
<tr>
<td>2020</td>
<td>43,358</td>
<td>27,886</td>
<td>15,472</td>
</tr>
<tr>
<td>2021</td>
<td>43,785</td>
<td>28,207</td>
<td>15,579</td>
</tr>
<tr>
<td>2022</td>
<td>44,262</td>
<td>28,558</td>
<td>15,703</td>
</tr>
</tbody>
</table>

The base-case annual H100 demand forecast is shown in Table 12.
Table 12: Base-case forecast of annual H100 demand for generation

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>North Island Demand (MW)</th>
<th>South Island Demand (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>4,115</td>
<td>2,146</td>
</tr>
<tr>
<td>2011</td>
<td>4,176</td>
<td>2,150</td>
</tr>
<tr>
<td>2012</td>
<td>4,111</td>
<td>2,065</td>
</tr>
<tr>
<td>2013</td>
<td>4,213</td>
<td>2,135</td>
</tr>
<tr>
<td>2014</td>
<td>4,277</td>
<td>2,154</td>
</tr>
<tr>
<td>2015</td>
<td>4,331</td>
<td>2,167</td>
</tr>
<tr>
<td>2016</td>
<td>4,390</td>
<td>2,183</td>
</tr>
<tr>
<td>2017</td>
<td>4,445</td>
<td>2,197</td>
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<tr>
<td>2018</td>
<td>4,494</td>
<td>2,221</td>
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<tr>
<td>2019</td>
<td>4,549</td>
<td>2,239</td>
</tr>
<tr>
<td>2020</td>
<td>4,608</td>
<td>2,258</td>
</tr>
<tr>
<td>2021</td>
<td>4,659</td>
<td>2,274</td>
</tr>
<tr>
<td>2022</td>
<td>4,716</td>
<td>2,292</td>
</tr>
</tbody>
</table>

Note: These tables are inclusive of losses but do not include the demand side or winter scaling adjustments.
11. **Appendix 3: Summer Energy and Capacity Risk**

The ASA does not assess summer capacity or energy risk. This is because at a national and island level, the New Zealand electricity system is at most risk of a capacity or energy shortage during winter. This appendix describes the most significant factors that reduce summer risk.

11.1 **Summer Energy Risk**

The two most significant factors that act to reduce the risk of an energy shortage in summer are demand and the hydro storage level.

Figure 34 shows New Zealand’s average monthly energy demand and hydro storage level from 1998 – 2012 (Winter defined as 1st April – 30th September).

Demand in winter is generally higher than in summer. This is due to greater heating and lighting consumption in response to the colder temperatures and shorter days.

This high demand combined with lower than average inflows reduces the hydro storage level in New Zealand’s major hydro storage lakes to its lowest level during September. Consequently, the period during which the New Zealand electricity system is at the greatest risk of energy supply shortages is the months leading up to this low point.

After September, inflows increase due to higher rainfall and the release of precipitation held as snow within the hydro catchment areas. This results in an increase in the hydro storage level, reducing the risk of energy supply shortages for the upcoming summer.
11.2 **Summer Capacity Risk**

The difference between summer and winter peak demand is the most significant factor that reduces the risk of a capacity supply shortage during summer.

Electricity systems are generally most at risk of a capacity supply shortage during the highest peak demand period of the year. In the North Island (and New Zealand) this has historically been on a cold winter evening when a high heating load combines with the typical evening peak.

North Island summer peak demand is significantly lower than winter peak demand. This reduces the risk of a capacity supply shortage, and therefore summer capacity risk is not assessed in the ASA.

Figure 35 shows the North Island’s highest half-hourly peak demand during summer and winter beginning winter 2007. Winter is defined as 1st April – 31st October (in blue); summer is defined as 1st November – 31st March (in yellow).

![Figure 35: North Island Half-hourly Peak Demand](Image)

Summer peak demand may grow relative to the winter peak over time; for example, irrigation load may contribute to a growing peak demand during the summer period. If the margin between winter and summer peak demand is forecast to reduce, the System Operator may include a summer capacity margin assessment in the ASA or elsewhere.