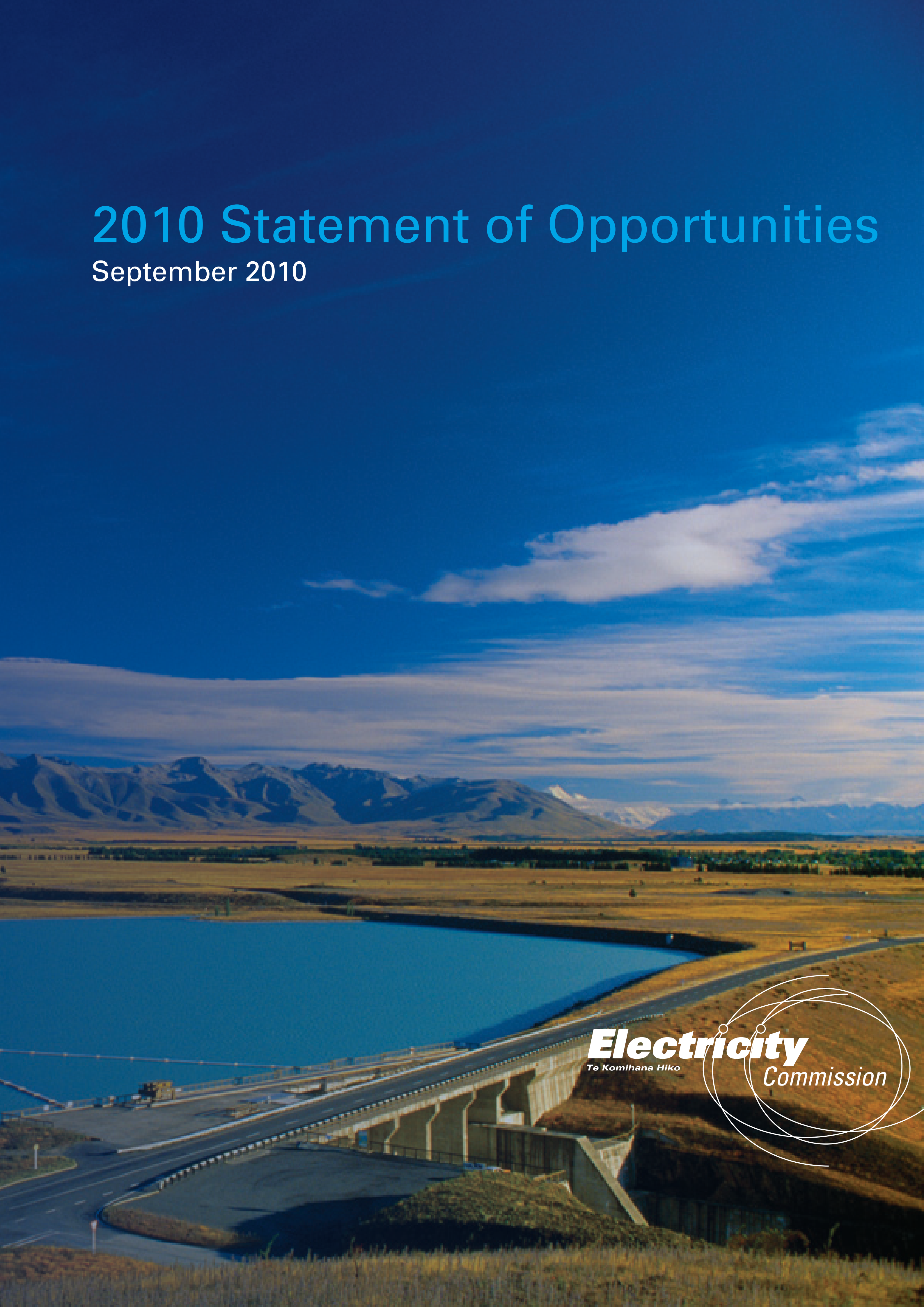
2010 Statement of Opportunities

September 2010



Electricity Commission
Te Komihana Hiko

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Statement of Opportunities

September 2010

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The Document

This document is the 2010 *Statement of Opportunities* (SOO) prepared by the Electricity Commission pursuant to part F of the Electricity Governance Rules 2003 (Rules).

The SOO is intended to identify potential opportunities for efficient management of the grid, over a 30-year time horizon, including potential investments in upgrades and transmission alternatives.

The regulatory context within which the SOO is prepared is set out in section 2.

Disclaimer

This document presents detailed forecasts to 2040. Forecasting developments over such a long timeframe involves a high degree of uncertainty. Although reasonable at this point having regard to the information available, the outlook to 2015 would change with different policy settings, fuel prices, resource availability, technology costs, and other factors. Projections beyond 2030 are attempting to describe a world in which our economy, society, environment, and technological options are most likely to be very different.

The scenarios presented have been developed on the basis of current knowledge. Not only will elements within each be reshaped by evolving local and world events, but individual scenarios may be impacted in the medium-to-longer term by paradigm shifts in generation and transmission parameters.

Therefore, projects presented in this SOO should be regarded only as illustrating the types of plant that might be constructed and locations in which plant they might be situated. Readers should consider the scenarios simply as one angle from which to model and test their investment intentions.

Rule 9.3 of section III of part F of the Rules states that the SOO is provided for information only. No liability will attach to the Commission, Transpower, or any other person, for the accuracy of Grid Planning Assumptions (GPA) set out in the SOO.

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Chair's foreword

This is the third and last *Statement of Opportunities* (SOO) prepared by the Electricity Commission under part F of the Electricity Governance Rules.

The first SOO was published in 2005 and the second in 2008. Since beginning work on the SOO, the Commission has reviewed and enhanced its models and analytical tools, information databases, and methodology for producing the document.

The 2010 SOO draws on the earlier versions and ongoing enhancement of research and analysis practice. It provides interested parties with independent information to consider in assessing the potential for grid management efficiencies and, in particular, investment in upgrades and transmission alternatives in particular.

I ask readers to remember that the SOO is not a plan for the future development of the grid or of generation. It does not tell investors (be they transmission or generation owners) where they may or may not propose new transmission lines or generating stations. Rather it is a set of scenarios as to how the transmission and generation of electricity may develop given a range of reasonable assumptions. The SOO's content and comment regarding future directions and events are the results of independent analysis undertaken by the Commission, based on forecasts and scenarios that are subject to various assumptions and limitations, and developed solely for the purposes of the SOO.

The SOO has three primary functions.

- It is intended as input to Transpower's grid planning activities, including use in:
  - forecasting whether the grids will meet the grid reliability standards;
  - identifying opportunities for economic investment;
  - developing formal proposals for grid investment; and
  - managing and operating grid assets.
- It represents a common information source for investors in generation, parties interested in evaluating transmission alternatives, other sector participants, and end users.

- It helps to inform consideration of the Grid Upgrade Plan (GUP), although the options and implications outlined are merely indicative, and the inclusion or exclusion of commentary on any particular investment in generation, transmission, or alternatives, should not be viewed as a fixed position. In deciding whether to approve or not approve an investment in Transpower's GUP investment, consideration must be given to the specific features of individual options in the context of circumstances prevailing at that time.

Under the proposed regulatory reforms following the Ministerial Review of the performance and governance of the electricity sector, the SOO will in future be produced by the Ministry of Economic Development (MED), and its nature may change.

However, provision of an independent and informed overview of the electricity industry and its future outlook will be an important part of the proposed Electricity Authority's market monitoring function.

The 2010 SOO has been compiled in consultation with industry and I thank the wide range of interested parties who contributed to its development. It is expected that this last SOO will have an important place in the transmission investment landscape and informed decision-making on grid management and development for the benefit of the economy and New Zealanders in general.

David Caygill
Chair

Glossary of abbreviations and terms

$m	million dollars
Act	Electricity Act 1992
ADMD	After Diversity Maximum Demand
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDS	Commission's Centralised Dataset
e3p	Energy Efficiency Enhancement Project
ETS	Emissions Trading Scheme
GAMS	General Algebraic Modelling System
GDP	Gross Domestic Product
GEM	Generation Expansion Model
GIP	Grid Injection Point
GIT	Grid Investment Test
GJ	Gigajoule
GPA	Grid Planning Assumptions
GPS	Government Policy Statement on Electricity Governance
GRR	Grid Reliability Report
GRS	Grid Reliability Standards
GUP	Grid Upgrade Plan
GW	Gigawatt
GWh	Gigawatt-hour—the amount of energy as measured by a rate of 1GW for a period of 1 hour
GXP	Grid Exit Point
HVDC	High-Voltage Direct-Current

HVDC upgrade	HVDC Grid Upgrade Investment Proposal
IL	Interruptible Load
kV	kilovolt, ie 1000 volts
LDC	Load Duration Curve
LNG	Liquefied Natural Gas
LPC	Load Probability Curve
LRMC	Long-Run Marginal Cost
LSI Renewables upgrade	Lower South Island Renewables Investment Proposal
MDS	Market Development Scenarios
MED	Ministry of Economic Development
Minister	Minister of Energy and Resources
MIP	Mixed Integer Programming
MoT	Ministry of Transport
MW	Megawatt
NAaN	North Auckland and Northland
NBT	North Bank Tunnel
NIGU	North Island Grid Upgrade
NPV	Net Present Value
NZAS	New Zealand Aluminium Smelters Limited
NZIER	New Zealand Institute of Economic Research
O&M	Operating and Maintenance
OCGT	Open Cycle Gas Turbine
PB	PB New Zealand Limited
PoE	Probability of Exceedance

PPL	Power Projects Limited
PSA	Power Systems Analysis
Regulations	Electricity Governance Regulations 2003
Rules	Electricity Governance Rules 2003
SNZ	Statistics New Zealand
SOI	Statement of Intent
SOO	Statement of Opportunities
SRL	Statistics Research Limited
TCC	Taranaki Combined Cycle
tCO_2-e	Tonne Carbon Dioxide Emission
WGIP	Wind Generation Investigation Project

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1. Executive summary

1.1 Introduction

Section III of part F of the Rules, which relates to grid upgrades and investments, requires the Commission to publish the SOO. The purpose of a SOO, as set out in rule 9.1.2, is to enable identification of potential opportunities for efficient management of the grid, including investment in transmission upgrades and transmission alternatives. In order to achieve this purpose, a SOO needs to include the information interested parties require to evaluate opportunities for investment and identify possible solutions for meeting electricity supply requirements.

The Government Policy Statement on Electricity Governance (GPS) states that the SOO should be prepared at least every two years, and should incorporate electricity demand and supply forecasts and help identify transmission network investment opportunities and alternatives and facilitate long term planning.

The full regulatory context within which the SOO is prepared is set out in section 2.

1.2 Electricity demand

Besides its inhouse modelling team, the Commission draws extensively on specialist external advice, academic literature, and insights from other parties involved in electricity demand forecasting. These sources have been used to develop a demand forecast covering the period to 2040 for the purposes of this SOO.

Statistics New Zealand's (SNZ) population growth projections have increased significantly, compared to the projections used to forecast demand in the 2008 SOO. The changed scenarios produce an increase in projected Gross Domestic Product (GDP) and, consequently, in electricity demand.

Total national electricity demand is projected to increase at an average of 1.5 per cent a year to 2040, compared with 1.3 per cent growth a year projected in the 2008 SOO. Growth to 2020 is projected to average 1.8 per cent a year, slowing to an average of 1.2 per cent a year by 2040.

Demand at a regional level is estimated by allocating the national-level projections to each region, based on regional population and GDP projections. North Island demand is forecast to grow at an average rate of 1.7 per cent a year to 2040, and South Island demand at an average of 0.9 per cent a year. Rates of growth in the South Island in the short-to-medium term are expected to be higher than the projected long-term trend, owing largely to growth driven by expansion of irrigation and dairy processing.

The SOO also forecasts national and regional-level peak demand.

At a national level, the rate of growth in peak demand has generally remained close to the rate of growth in total energy demand. That is reflected in projections to 2040. The relationship between the two can, however, vary significantly, particularly in smaller areas and in regions that may be affected by growth in specific industries that operate off peak or, alternatively, where there is rapid growth in peak appliance use. While the peak forecasts assume a close relationship between growth in peak demand and growth in total energy demand across the country, individual areas are subject to higher levels of uncertainty in growth rates. Detailed regional peak forecasts are provided in Appendix 1.

1.3 Electricity Supply

Generation scenarios have been developed using the Commission's Centralised Dataset (CDS) and Generation Expansion Model (GEM). The CDS is a set of historical metering, market, hydrological, and network-related data maintained and published by the Commission. The CDS is intended to support transmission-planning processes by providing information to assist with decisions on transmission and transmission alternatives.

GEM is the Commission's generation expansion model.[1] It was constructed in late 2006 to support the production of generation capacity expansion paths under various future scenarios. GEM is a mathematical programming (ie optimisation) problem of the Mixed Integer Programming (MIP) type. It is coded using the General Algebraic Modelling System (GAMS) software and is solved with the CPLEX solver, (although alternative MIP/LP solvers could be used). GEM is undergoing continual development.

To produce a 'reasonable range of credible forecasts and scenarios' for GPA purposes, as required by rule 10.2.1 involved three main steps.

- Assemble input data.
- Develop the scenario 'stories', by identifying the key drivers and assumptions (for example, fuel costs, fuel availability and carbon prices that will influence future development paths, and determine the combination of drivers that will apply in each scenario.

1 In the interests of transparency and continuous improvement the Commission makes the GEM programs and data files freely available. GEM is frequently updated, with any changes posted on the Commission's website.

- Run the models to develop each generation scenario.

Each of the five scenarios extending to 2040 (Table 1) has been developed to represent plausible views of future possibilities, taking into account most of the uncertainties.

However, none is presented as a 'most likely' future scenario and all are assigned equal weighting.

GEM, a long-term planning model, was used to develop the scenarios. Given a set of assumptions, GEM aims at minimising the capital and operating and maintenance (O&M) costs over the entire time horizon while meeting various constraints, eg meeting peak demand, High-Voltage Direct-Current (HVDC) capacity.

Table 1 Scenario outlines

Scenario	Description
2010 Sustainable path	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction with a long-term average carbon charge of $60/t. In addition, no new large gas discoveries are made in the future. The resultant high gas price make gas-fired baseload generation relatively uneconomic to run and forces some to be decommissioned. Renewable generation, including hydro, wind, and geothermal, backed by thermal peakers for security of supply, are the least-cost option under this scenario. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. New energy sources are brought on stream in the late 2020s and 2030s, including biomass, marine, solar, and carbon capture and storage. Demand-side[2] participation becomes a more important feature of the market, driven by consumer pressure.
2010 SI wind	Wind development proceeds at a slightly more rapid pace than in 2010 Sustainable path. The major wind farms having or currently seeking resource consent are built in the lower South Island in the early years. As with the 2010 Sustainable path, a high carbon charge and gas price lead to the decommissioning of some thermal plants. These plants are replaced by renewable generation. Thermal peakers supplement renewable development. New technologies are available after 2020. Less geothermal generation is available to this scenario because of resource consenting issues.
2010 Medium renewables	A 'middle-of-the-road' scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. The lead time between gas discovery and production leads to gas shortage between 2020 and 2030. Tiwai smelter is decommissioned in the mid-2020s.

[2] Demand-side assumptions have not changed significantly from the previous SOO.

Scenario	Description
2010 Coal	The assumed low carbon charge and greater gas availability after 2030 make new gas-, coal-, and lignite-fired plants economic. Geothermal resources are still the least-cost option, with all the high-temperature resources developed prior to 2025. Little new hydro can be consented and some existing hydro schemes have to reduce their output, owing to difficulty in securing water rights. Electric vehicle uptake is relatively rapid after 2020.
2010 High gas discovery	Major new gas discoveries keep gas prices low over the entire time horizon. Some existing thermal power stations are replaced by new, more efficient gas-fired plants. New CCGTs and gas-fired peakers are built to meet the country's power needs; the most cost-effective renewables are also developed. The demand-side remains relatively uninvolved.

In order to cover a wide range of outcomes key drivers, such as the carbon charge, fuel cost, and fuel availability, are varied across the scenarios. Industry-participant and other expert advice was obtained to ensure that the input assumptions for fuel and generation were appropriate for scenario development, and that the key drivers, although varied, remained within plausible limits.

The scenarios are expressed as build schedules, ie lists of projects that it is assumed will be constructed, by commissioning year, including generator decommissioning.[3] It is emphasised that the generation projects included in each scenario are to be regarded as a representative mix, consistent with the 'story' of that scenario. The inclusion of one project rather than another should not be considered as indicative of a Commission view that the included project is more technically feasible, more likely to obtain a resource consent, or more economic. Projects are simply included as instances of the types of plant that might be constructed and the locations in which the plant might be located. Table 2 summarises the key features of the 2010 SOO scenarios.

[3] These schedules are reproduced in full in Appendix 2 for each of the scenarios.

Table 2 Timelines to 2040 for the scenarios (based on summarised GEM output)

Scenario	2010–2012	2013–2018	2019–2024	2025–2030	2031–2040
2010 Sustainable path	New wind and geothermal developments, with thermal peakers to provide security of supply. New HVDC Pole 1.	One coal-fired unit at Huntly closes down. Hydro and geothermal development backed by thermal peakers.	Two coal-fired units at Huntly and Taranaki Combined Cycle (TCC) close down. Hydro and geothermal development backed by demand-side response.	Energy Efficiency Enhancement Project (E3p) is decommissioned. Hydro, NI wind, marine, and biomass development backed by thermal peakers and demand-side response.	Consumer electric vehicles becoming widespread with vehicle-to-grid technology in place. Renewable development continues. Carbon capture and storage (CCS), solar, pumped hydro, and marine energy developed.
2010 SI wind		Important SI wind developments, backed by thermal peakers.	Two coal-fired units at Huntly and Otahuhu B close down. Hydro, wind and geothermal developments.	Wind development backed by more thermal peakers and demand-side response.	More hydro and wind development. One CCS coal-fired unit at Huntly is commissioned.
2010 Medium renewables		Geothermal development.	One coal-fired unit at Huntly and TCC closes down; replaced by a more efficient coal-fired station and geothermal developments.	One coal-fired unit at Huntly closes down. Tiwai smelter begins to close down. Little generation development.	Mixed renewables and Combined Cycle Gas Turbine (CCGT) built.
2010 Coal		Geothermal development.	One coal-fired unit at Huntly and TCC closes down, replaced by two more efficient coal-fired stations.	Lignite plant built in the South Island.	One coal-fired station and three new gas-fired stations are commissioned.
2010 High gas discovery		One coal-fired unit at Huntly closes; replaced by two CCGTs.	One coal-fired unit at Huntly closes and some geothermal developments.	One coal-fired unit at Huntly closes. Two other CCGTs built in the North Island.	Gas-fired stations continue to provide a high proportion of supply.

1.4 Power systems analysis

1.4.1 Overview

Rule 9.1.1 of section III of part F of the Rules requires the SOO to include an analysis of the performance of the Power System (PSA) against the GPA and the Grid Reliability Standards (GRS).[4]

The purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives. The Rules also provide that in preparing the SOO, the Commission must have regard to the reasonable requirements of Transpower, investors in generation, other participants, end-use consumers, and those interested in evaluating transmission alternatives.

The PSA contributes to the purpose, and furthers the principle, by identifying when the grid, in any given scenario (ie the GPA), will no longer meet the GRS.

The point at which it is anticipated that the transmission grid will no longer meet the GRS represents an opportunity for efficient management of the grid, including investment in upgrades and transmission alternatives. The opportunities signalled in the SOO are only transmission opportunities, but the Commission emphasises that in some situations opportunities for investment in transmission alternatives may arise at the same time.

1.4.2 Principal conclusions

North Island

The North Island maximum demand is forecast to increase from around 4900MW in 2010 to around 8700MW in 2040. The increase, as well as a portion of the existing demand, is forecast to be supplied by increased North Island generation in all scenarios. The scenarios include net[5] new North Island generation in the range 4500MW (High gas discovery) to 6700MW (South Island wind).

4 Rule 9.1.1.3 of section III of part F.

5 All scenarios include some decommissioning of existing North Island generation, in the range 1300MW (South Island wind) to 2100MW (Sustainable path). Total new North Island generation is in the range 6000MW (High gas discovery) to 8000MW (Sustainable path and South Island wind). The ‘net’ new generation is equal to the total new generation minus the decommissioned generation.

The major approved transmission projects, including the North Auckland and Northland upgrade (NAaN), the North Island Grid Upgrade (NIGU), the Wairakei Ring augmentation and the HVDC Pole 3, will significantly contribute to the capability of the grid to meet the GRS. The PSA has identified the following further significant transmission opportunities in the North Island (a full list is set out in section 8.2).

- 220kV transmission capacity between Pakuranga and Penrose, in the Auckland region, around 2025
- 220kV transmission capacity between Atiamuri and Ohakuri, in the Wairakei region, around 2040
- 220/110kV interconnection capacity at various stations around the North Island, from North Auckland south to Wellington
- 110kV transmission capacity at various locations around the North Island

South Island

The South Island maximum demand is forecast to increase from around 2350MW in 2010 to around 3250MW in 2040. Depending on the scenario, the increase is forecast to be supplied by either increased South Island generation or a decrease in HVDC transfer due to increased North Island generation. The scenarios include new South Island generation in the range 480MW (High gas discovery) to over 2300MW (Sustainable path).

The major transmission expansion already approved in the South Island, including the HVDC Pole 3, coupled with potential North Island generation growth across all scenarios, will significantly contribute to the capability of the grid to meet the GRS. The PSA has therefore identified only limited transmission opportunities in the South Island, including the following. A full list is set out in section 8.3.

- 220kV support for the Upper South Island, around 2025 and later
- Additional 220/66kV interconnection capacity in Christchurch, Timaru, and, depending on the scenario, Otago/Southland

The relatively high-level PSA identifies only major potential investments. There may be a significant amount of additional investment required in addition to the major potential investments summarised. The additional investments are set out in more detail in section 8.

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2. Regulatory context

2.1 Introduction

This section:

- briefly summarises the current regulatory framework;
- explains the purpose and content of the SOO (in the context of the current regulatory framework); and
- discusses the future of the SOO in light of the proposed regulatory reforms following the Ministerial Review of the performance and governance of the electricity sector.

2.2 Summary of current regulatory framework

2.2.1 Introduction

The Commission is responsible for regulating the operation of the electricity industry and wholesale and retail markets in accordance with the Electricity Act 1992 (the Act).

In exercising its powers, the Commission must have regard to the principal objectives and the specific outcomes listed in section 172N of the Act.

The Act also sets out specific functions of the Commission, including:

- administering the Electricity Governance Regulations 2003 (Regulations) and rules (section 172O(1)(b)); and
- giving effect to GPS objectives and outcomes (section 172O(1)(j)).

Part F of the Rules sets out a series of processes that the Commission must follow to develop and authorise comprehensive transmission pricing, transmission contracting, transmission investment arrangements, and interconnection services.

Section III of part F[6] sets out rules for grid upgrades and investments. In summary, section III seeks to facilitate timely investment in transmission infrastructure in an efficient and cost-effective way. It is under section III that the Commission is required to prepare and publish the SOO.

[6] Unless stated otherwise, each reference in this document to a rule is to a rule in section III of part F of the Rules.

2.2.2 The Government Policy Statement (GPS)

Under section 172ZK of the Act, the Minister of Energy and Resources (the Minister) must set objectives and outcomes for the Commission.[7] The Commission must report against the specified GPS objectives and outcomes in a *Statement of Intent* (SOI), in accordance with the Crown Entities Act 2004.[8]

The current GPS was published in May 2009.

Paragraph 77 of the May 2009 GPS relates specifically to the SOO. It states that the SOO should:

- incorporate electricity demand and supply forecasts;
- enable identification of potential opportunities for:
  - efficient management of Transpower's transmission network including investment in system expansions, replacements, and upgrades
  - transmission alternatives (notably investment in local generation, demand-side management, and distribution network augmentation)
- facilitate long-term planning for timely securing of easements and resource consents, including the connection of renewables; and
- be prepared at least every two years.

The May 2009 GPS also states that GUPs should be consistent with, among other things, the forecasts in the SOO.[9]

2.2.3 Relationship between with the Grid Investment Test and the GRS

The information in the SOO is relevant to the Grid Investment Test (GIT)[10] and the GRS.[11] The relationship between the SOO, the GIT, and the GRS is summarised here to explain the wider context for the SOO and the approach to its preparation.

The GIT is essentially an economic test, with an expected net market benefits assessment at its heart. The GRS set out the reliability standards to which the grid must be planned.

7 Section 172O(1)(j).
8 http://www.electricitycommission.govt.nz/publications
9 Paragraph 80.
10 Schedule F4 of section III of part F.
11 Schedule F3 of section III of part F.

The SOO is relevant to the GIT because clause 6 of the GIT requires that in applying the GIT:

- Market Development Scenarios (MDS), which are the scenarios in the SOO, must be used, unless the Commission determines that other scenarios are more appropriate;
- the probability of occurrence of an MDS must be as set out in the SOO; and
- the number of scenarios must be the same as the number of MDS in the SOO.

The SOO is relevant to the GRS because:

- the GRS provide a basis for the SOO and for Transpower to prepare GUPs; [12]
- the SOO must set out the GRS;[13]
- the SOO must include a power systems analysis (PSA) against the GPA and the GRS;[14] and
- the GRS requires that the expected level of reliability is assessed having regard to the possible future scenarios set out in the SOO.[15]

Accordingly, the SOO, the GIT, the GRS, and GUPs are all interrelated.

2.3 Purpose and content of the SOO

Rule 9.1.2 provides that the purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid, including investment in upgrades and investment in transmission alternatives.

In preparing the SOO, the Commission must have regard to two key principles. First, the SOO should aim to meet the reasonable requirements of Transpower, investors in generation, other participants, end-use customers and those interested in evaluating transmission alternatives.[16] Second, the SOO should reflect good electricity industry practice.[17].

12 Rule 4.2 of section III of part F.
13 Rule 9.1.1.1 of section III of part F.
14 Rule 9.1.1.3 of section III of part F.
15 Clause 6 of schedule F3 of section III of part F.
16 Rule 9.2.1 of section III of part F.
17 Rule 9.2.2 of section III of part F.

Rule 9 also provides[18] that the SOO must contain:

- the GRS;
- the GPA; and
- a PSA against the GPA and the GRS.

The SOO is intended to signal opportunities for investment and provide key information that may assist interested persons to evaluate those opportunities and identify possible solutions, including investment in transmission or transmission alternatives.

The SOO identifies, on a non-exhaustive basis, likely constraints in the transmission network, the possible timing of the emergence of those constraints, and some potential options for resolving them.

The SOO is a snapshot of the Commission's views at the time the SOO is published. Therefore, the SOO sets out possible states of the electricity system based on the information available to the Commission at the time the SOO is published. The SOO is not a plan for investing in, or managing, the electricity system. The inclusion or exclusion of analysis or discussion about any particular investment in generation, transmission, or alternatives should not be taken as the Commission expressing a settled view on any option.

2.3.1 Grid Reliability Standards

Rule 9.1.1.1 requires the SOO to set out the GRS.

The GRS[19] are the standards against which the performance of the power system is analysed under each scenario contained in the GPA. The purpose of the GRS is to provide a basis[20] for:

- the Commission to publish the SOO;
- Transpower to prepare GUPs; and
- other parties to approve opportunities for transmission investments and transmission alternatives.

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[18] Rule 9.1.1 of section III of part F.

[19] The GRS can be found at: http://www.electricitycommission.govt.nz/pdfs/rulesandregs/rules/rulespdf/PartFSectionIIIScheduleF3-gridreliabilitystandards-17Jan08.pdf

[20] Rule 4.2 of section III of part F of the Rules.

2.3.2 Summary of the Grid Reliability Standards

The GRS are set out in schedule F3 of section III of part F of the Rules.

The essence of the GRS is contained in clause 4 of schedule F3, which states as follows.

> 'For the purpose of clause 3, the **grid** satisfies the **grid reliability standards** if:
>
> 4.1. the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all **economic reliability investments** were to be implemented; and
>
> 4.2 with all **assets** that are reasonably expected to be in service, the power system would remain in a **satisfactory state** during and following any **single credible contingency event** occurring on the **core grid**.'

Therefore, the GRS has two limbs.

- An 'economic limb', which is applicable to the entire grid.
- A 'deterministic limb', comprising the *N*–1[21] safety net applicable only to the core grid.[22]

The economic limb is a generic reliability standard for the entire grid. The deterministic limb sets a minimum reliability standard *(N–1')* for the core grid.[23]

2.3.3 Power systems analysis for the SOO

Rule 9.1.1.3 requires the SOO to include an analysis of the performance of the power system against the GPA and the GPS. In practice, this means that the Commission:

- models inter-regional transmission against the GRS to determine when transmission constraints (based on the GRS) may occur; and
- analyses the power system for each generation scenario in the GPA, and identifies options for transmission augmentation and alternatives when the modelling above determines that a constraint may occur.

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[21] Where '*N*' refers to a number of transmission facilities and '-1' refers to a 'single credible contingency event', as defined in part A of the Rules.

[22] As defined in schedule F3A of section III of part F.

[23] For the non-core grid, there is no minimum *N*-1 standard, and there is also the possibility of a higher than *N*-1 standard if the economic assessment supports this.

Previous PSA involved analysing the constraints on power flow between regions using a load flow, and listing measures to relieve the constraints in a rough hierarchy, based on the cost of the measures.[24] The results of this inter-regional analysis have been used in the latest PSA and have not been repeated for this SOO.

The inter-regional constraints were determined by an *N*-1 security analysis that considered the following subset of single credible contingency events.

- A single inter-regional transmission circuit interruption
- An HVDC link single pole interruption

PSA verified the operational credibility of the finalised generation scenarios, by modelling the power system for each scenario over a 30-year horizon 2010–2040. The analysis was based on load flow simulations to verify whether the power system would meet the deterministic limb of the GRS, and to determine the type of transmission augmentation opportunities that might achieve this. As this is only a high-level analysis, the economic limb of the GRS was not applied. Consequently, it should be noted that the transmission augmentation opportunities in the PSA have not been optimised and that alternative transmission augmentations, or transmission alternatives, may well be justified under the economic limb of the GRS.

As the demand for energy grows, the supply transformer capacity will need to be augmented to provide a secure supply to the load on low voltage buses. Modelling these supply transformer augmentations is likely to involve a considerable amount of work. Customer-specific issues need to be taken into account and there is significant uncertainty in the nature of the augmentation because individual Grid Exit Point (GXP) demand growth is harder to forecast than national demand growth. On the other hand, not modelling the augmentations will result in an unrealistically high reactive consumption in the supply transformers. Instead of augmenting supply transformers, the analysis took the approach of maintaining a constant load power factor as viewed from the high voltage side of GXP supply transformers and eliminating the supply transformers.

The Commission considers that a simplified approach to the application of the GRS is appropriate for the purpose of the SOO. To investigate whether at each connection point the GRS was met would involve a substantial amount of PSA. The Commission notes that Transpower is required to do this as part of the Grid Reliability Report (GRR), and duplicating that work cannot be justified.

[24] 'Inter-Area Transmission Capacity', System Studies Group NZ Limited, S013–02 Draft Revision 9, 21 September 2006.

Further details on the approach adopted for the PSA, including the list of assumptions used in the analysis, is detailed in Section 8.

2.4 Future purpose of the SOO

Under the proposed regulatory reforms following the Ministerial Review of the performance and governance of the electricity sector, the SOO will change. It is intended that future SOOs will be prepared by the Ministry of Economic Development (MED) and their content may be substantially different. The current relationships between the SOO, the GIT and the GRS, and the role of the SOO in providing input for Transpower's grid planning activities and to help inform consideration of GUPs, will no longer apply.

However, the 2010 SOO will remain relevant for transmission investment proposals submitted to the Commerce Commission during the transitional period from 1 October 2010 and 1 October 2011. That is because the Commerce Commission is required to apply the GIT during the transitional period, and the scenarios in the SOO are the starting point for the scenarios used in applying the GIT clause (refer clause 6 of the GIT).

Transpower's grid reporting obligations under sections III[25] and VI[26] of part F of the Rules, which are based on aspects of the SOO, will also change.

[25] Rule 12A of section III of part F.

[26] Rule 6.2 of section VI of part F.

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3. Electricity demand forecasts

3.1 Introduction

Electricity demand forecasts[27] are a key component of the GPA.

The Commission has an inhouse specialist modelling team. It also draws on external advice, academic literature and publications, and the insights gained by other parties involved in electricity demand forecasting.

Throughout this section, the term 'energy demand' is used to refer to total electrical energy demand over a period of time, as opposed to peak demand, which is the highest rate at which energy is consumed[28] over the relevant time period.

The energy and peak demand forecasts presented in this document have been revised upwards compared with those presented in the 2008 SOO. This is mainly a result of significant changes in the underlying forecasts of population and GDP used to forecast demand.

The following sections set out the review process and the methodologies used to prepare the updated forecasts.

3.2 Forecasting national energy demand

The GPA, and the demand projections contained in the GPA, are required to have a length of outlook commensurate with consideration of future investment in long-life transmission assets. The Commission considers that a 30 year timeframe is appropriate, and accordingly, the Commission has prepared demand forecasts out to 2040.

The national and regional energy demand forecasts are based on annual periods from 1 April to 31 March. This is primarily driven by the availability of key input data that is published on a March year-end basis.

The forecasts presented here are of electricity taken off the national transmission grid at the GXPs.

[27] The term 'forecast' is often used to describe a prediction of future outcomes. In the context of the SOO, the term 'forecast' is used to describe projections or extrapolations made by the Commission using a number of models and assumed inputs.

[28] National energy forecasts are usually measured in gigawatt hours (GWh) whereas the rate of energy consumption is measured in gigawatts (GW).

Electricity is lost in transportation across the national grid from the grid injection points (GIPs) (generation) to the GXPs. Therefore the total amount of generation is higher than total GXP off-take. Besides transmission losses, some electricity is lost across the local distribution network between the GXP and the customer's meter. The combined effects of these losses and locally connected generation (embedded generation) mean that total demand measured at customers' meters is different from that measured at the GXPs.

The forecasts presented in this section do not include reductions or increases in demand that may occur as a result of highly uncertain influences such as the introduction of significant new demand-side management measures, or the uptake of plug-in hybrid or fully electric vehicles. Similarly, while the impact of ongoing energy efficiency improvements on demand is implicitly included in the forecasts, step changes in demand that may result from the introduction of significant new policies are not. The impact of such events is explored through demand-side scenarios, discussed in section 3.5.

3.2.1 Forecasting approach

The Commission uses econometric models for the development of its long-term national energy forecasts. The econometric models use the historical relationship between electricity demand and key drivers, such as GDP, to produce future demand projections.

The resulting forecasts are therefore very much 'business as usual'; if the relationship between electricity demand and the drivers of demand remains unchanged in the future, and if the forecasts of those drivers are correct, then the electricity forecast should be correct. New uses for electricity in the future, more energy efficiency, major changes in industry, unforeseen global issues, could produce different results.

Some uncertainty in the assumed drivers of electricity demand has been modelled into the 'business as usual' forecast. However, the 'true', uncertainty in the assumed drivers of electricity demand. However, the 'true' uncertainty in the SOO, and any other forecasts, remains unknown. The modifications to reflect uncertainty are set out in section 3.2.4.

Demand is split into three main sectors for the purpose of preparing the forecasts.

- Residential;
- Commercial and industrial
- Heavy industrial (Tiwai Aluminium Smelter)

Each of the above sectors has different characteristics. Accordingly, different econometric models and assumptions are used for each, tailored to the sector's particular characteristics.

3.2.2 Key drivers

The Commission tested the relationships between a number of key economic variables, or drivers (historical population, GDP, electricity prices, and household figures) and historical electricity demand for each sector.

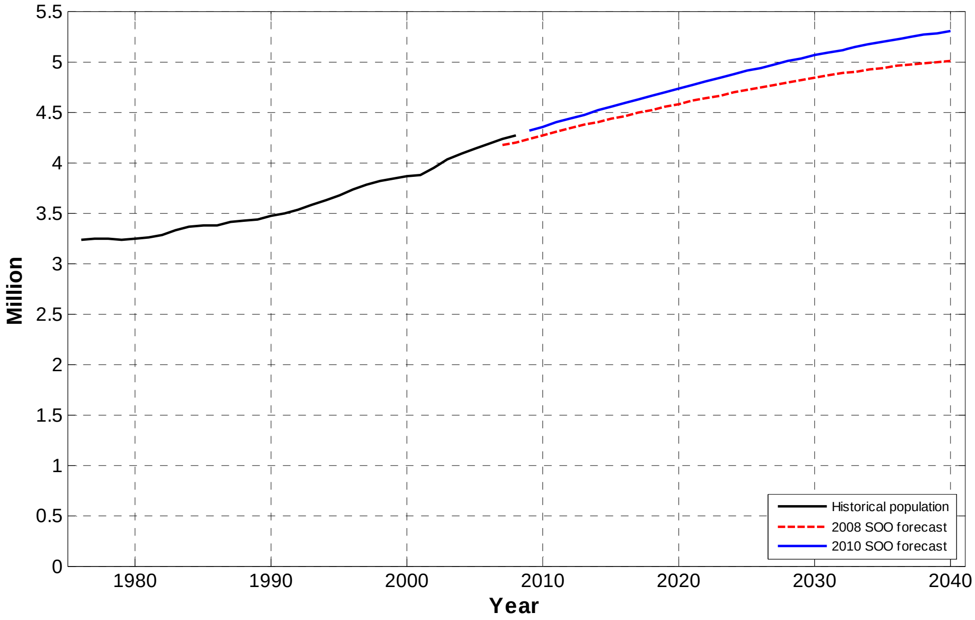
Historical economic data is readily available. However, it is subject to changes in measurement techniques and definitions over time. Accordingly, obtaining a reasonably consistent long-term series often requires some adjustments to historical data. Long-term forecasts of economic variables are more difficult to source and their availability has some bearing on the selection of variables used in the econometric models.

Population

Historical population data is available from Statistics New Zealand (SNZ). There have been some changes in the definitions used for measuring total population. Adjustments were made to the earlier population data to produce a consistent series.

SNZ also publishes long-term projections of population based on different scenario assumptions around birth, death, and immigration rates. The mid-level growth scenario was used as a baseline for SOO forecasting. This scenario assumes medium fertility, medium mortality, and long-term net migration of 10,000 people a year. Figure 1 shows historical and forecast total New Zealand population out to 2040.

Figure 1 Total New Zealand population—mean forecast



The population forecasts are significantly higher than those used to forecast demand for the 2008 SOO. The change is mainly because of an update to birth rate and life expectancy assumptions by SNZ.

Gross domestic product

Historical real GDP statistics are published by SNZ. Older GDP values are expressed in different base-year values compared with more recent figures, so the various series have been converted to a single comparable group.

Long-term forecasts of GDP were obtained from the New Zealand Institute of Economic Research (NZIER). The NZIER forecasts are based on SNZ population and workforce projections, and assumed changes in productivity. The forecasts have increased compared with those used in the 2008 SOO as a direct result of the changes in projected population.

Figure 2 and Figure 3 show historical and forecast GDP in absolute and percentage growth terms.

Figure 2 Total New Zealand real GDP ($1995/1996)—mean forecast

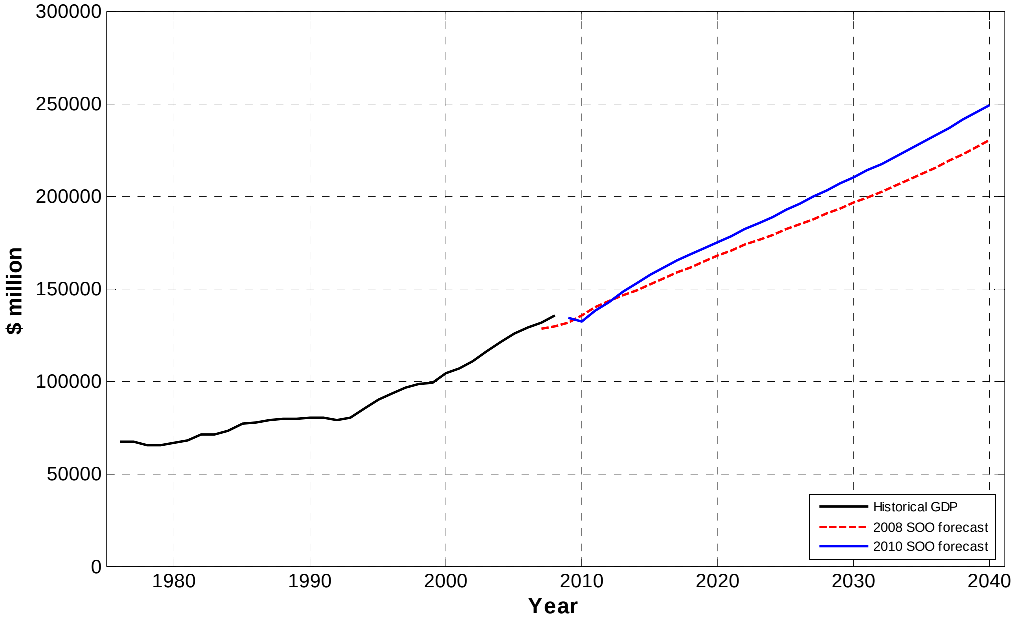
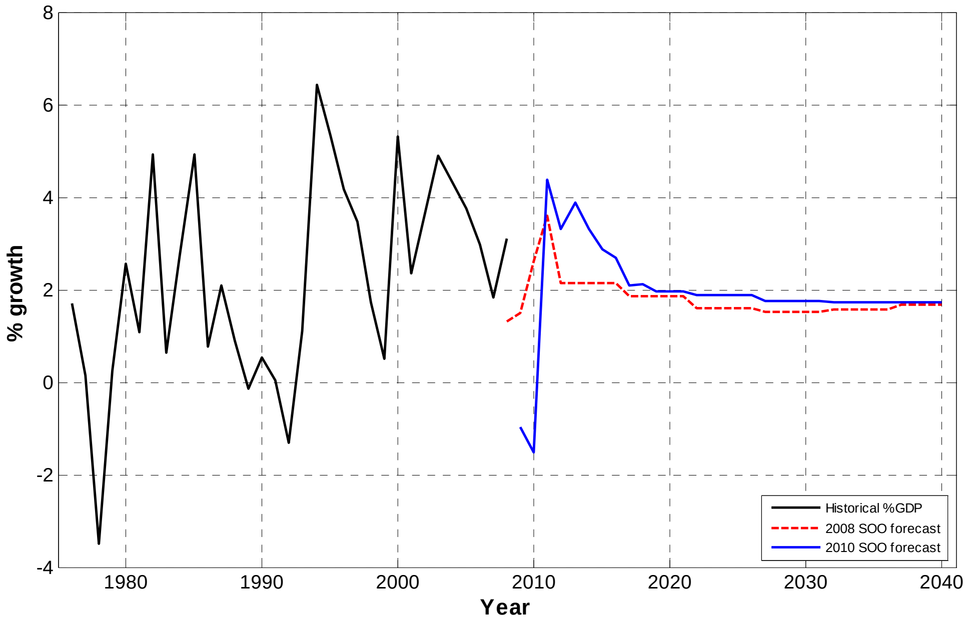


Figure 3 Total New Zealand real GDP ($1995/1996)—percentage growth

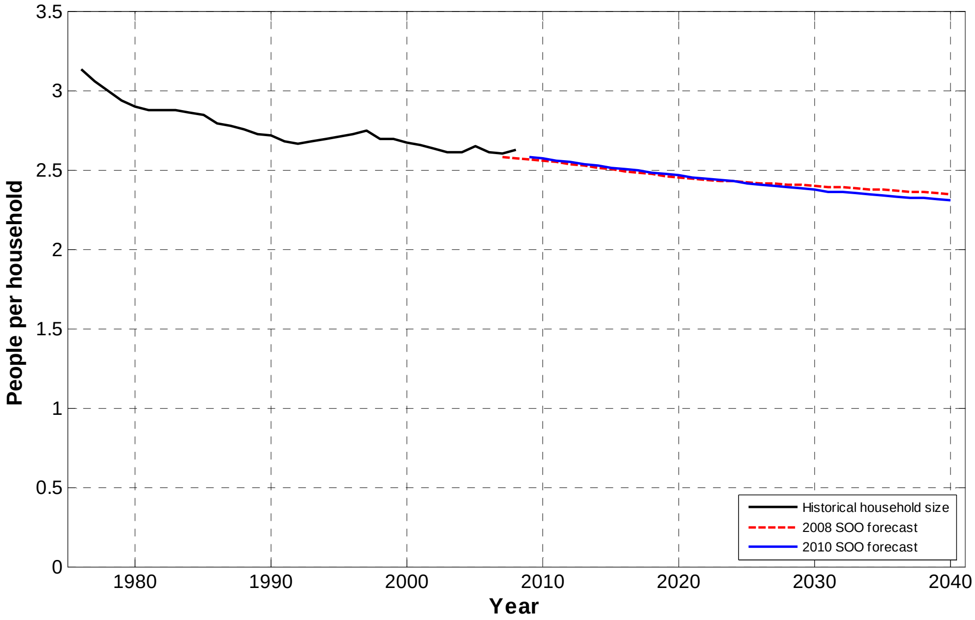


Households

Historical data on the number of residential consumers is published in MED's Energy Data File. SNZ produces a number of projections of future household numbers based on different scenario assumptions around population and household composition. The definition of the 'consumers' data contained in MED's Energy Data File differs slightly from the household definition used by SNZ. For the purposes of this SOO, SNZ projections were therefore adjusted to retain comparability with MED's Energy Data File series.

The household projections are combined with the population projections to derive a forecast of the projected change in household size. Figure 4 shows historical and forecast average household size.

Figure 4 Average New Zealand household size



Demand Data

Historical demand data for the residential, commercial, and industrial sectors is published in MED's Energy Data File.

3.2.3 Model selection

A number of different models for each sector were assessed, using different data-fitting techniques and different combinations of key drivers, in order to determine which combination yielded the best predictor of demand for each sector. These included changing the sector definitions in order to test the impact of excluding additional heavy industrial loads from the commercial and industrial sector. Table 3 summarises the key drivers used in the residential, commercial and industrial, and heavy industrial models.

Residential model

The residential model is a log-based model that relates demand per capita to GDP per capita, households per capita, and real residential electricity prices. The model uses consumption and driver data from 1974 onwards.

Commercial and industrial model

The commercial and industrial model relates total commercial and industrial demand to GDP, with an adjustment for years where there was a perceived electricity supply shortage.

The key decision affecting the commercial and industrial forecasts revolves around the modelling period used for assessing the historical relationship between demand and GDP. Reasonably robust electricity consumption data exists back to 1972.

There is, however, evidence of significant structural changes in the economy in the mid-late 1970s and early 1980s, supported by a statistically significant breakpoint in the relationship between GDP and electricity demand before and after the late 1980s. The Commission has taken the view that the data from the late 1980s onwards is likely to be a better predictor of future demand growth than earlier data.

Heavy industrial model

The heavy industrial model is limited to projecting consumption by the Tiwai Aluminium Smelter.

The forecast for the aluminium smelter is simply that it will maintain its existing levels of demand, plus any committed increases in consumption.

Table 3 Drivers used in the residential, commercial and industrial, and heavy industrial model

Sector	Population	GDP	Number of households	Electricity prices	Model structure
Residential	✓	✓	✓	✓	Log-based model using data from 1974 onwards.
Commercial and industrial		✓			Linear model using data from 1986 onwards.
Heavy industrial (Tiwai Point smelter)					Fixed forecast based on maximum annual historical demand.

3.2.4 Uncertainty

A key problem with forecasting demand over long time periods is the high level of uncertainty that arises, owing to potential changes in the underlying drivers. The nature of opportunities for investment in transmission or transmission alternatives can be sensitive to uncertainty in demand forecasts. Therefore it is important that this uncertainty is understood and incorporated into the modelling process.

The Commission has used a Monte Carlo simulation technique to model uncertainty in the key drivers. This technique involves estimating distributions for key drivers used in the model. The model is then re-run many times, replacing the actual input data with data randomly drawn from the estimated distributions. This provides a range of forecasts that confidence limits can be based on.

Population

Uncertainty in the population forecasts has been addressed by applying a scale factor to the forecasts. The scale factors are sampled from a distribution created from the various Statistics New Zealand population scenarios.

The population uncertainty in each individual run of the model is used as an input to both GDP and the number of households in that same model run. This is done to maintain consistency among the various drivers within each run.

Gross domestic product

Uncertainty in the GDP forecasts is based around three different sources of variation. The population component of GDP is kept consistent with the population scaling within each model run, as discussed above. The productivity component is varied, based on an estimated range.

Finally, a random component is included to introduce shocks from changes in the international environment, such as overseas market conditions. The shock component is based on historical variation against the underlying trend.

Households

Uncertainty in forecast household sizes uses two sources of variation. The population change component of household numbers is kept consistent with the population scaling above within each model run. Household size is varied, based on the Statistics New Zealand household scenarios.

Electricity prices

Residential electricity price uncertainty is dealt with by applying a simple normal distribution with a standard deviation of 10 per cent to the base case price forecast. The relatively low price elasticity in the model means that there is only a small impact associated with varying electricity prices.

Embedded generation

Embedded generation is incorporated as a fixed factor in the baseline forecast. The volume of embedded generation used for assessing forecast sensitivity is held as a constant proportion of total national demand across the various model runs.

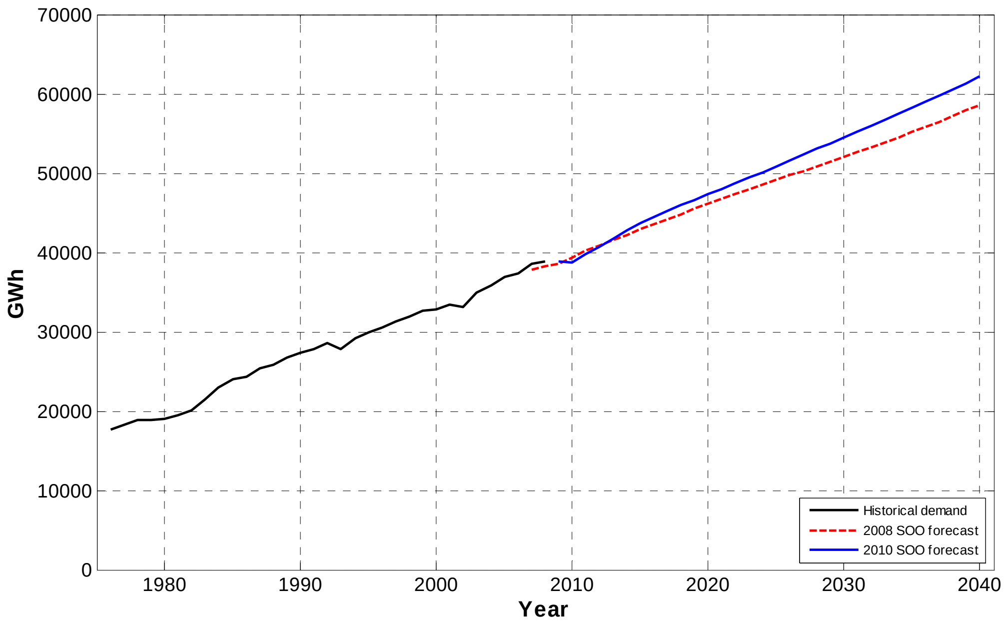
3.2.5 National demand forecasts

This section outlines the Commission's national electricity demand forecasts, produced through the modelling approach described above.

A table presetting the 80 per cent confidence limits and the sectoral breakdown for national demand forecast out to 2040 is set out in Appendix 3.

Figure 5 shows historical total national demand, the 2008 SOO forecasts, and the revised 2010 SOO forecasts.

Figure 5 Historical and forecast total national energy demand



As noted earlier, the substantial increase in the revised forecasts compared with the 2008 SOO is driven mainly by the increase in forecast population, and the flow-on effects on GDP and household numbers.

The demand growth rate is initially low due to forecast GDP growth being lower than average until 2010. At that point growth rates increase over the medium term, and then ultimately taper off as economic growth and population growth gradually drop away.

NZIER carried out a high-level review of the Commission's forecast methodology. Statistics Research Limited (SRL) was also engaged to carry out a more detailed technical review of the forecast models.

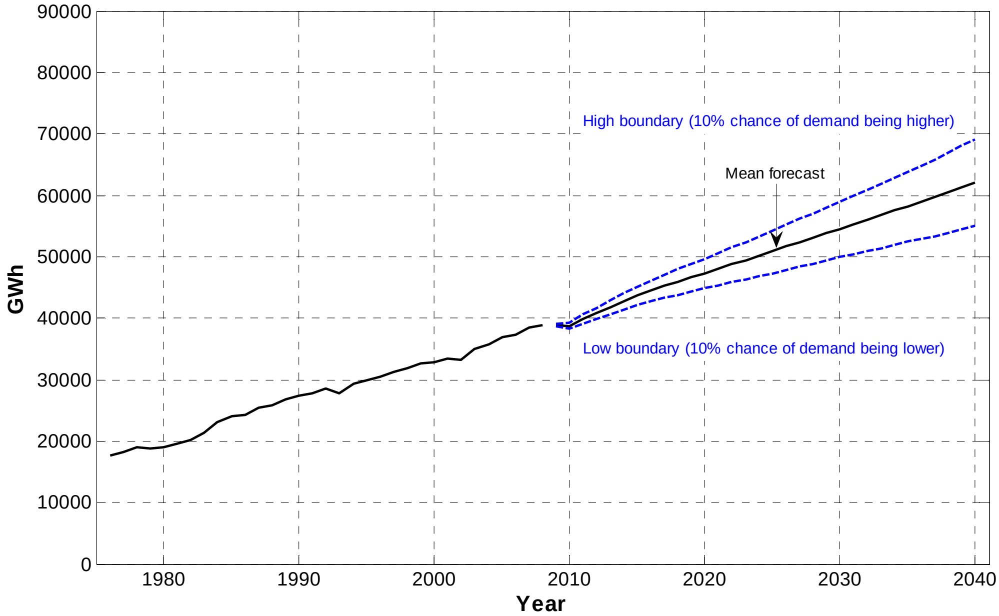
Both reviews broadly supported the current approach, but made a number of recommendations for the long-term development of the models, including improving documentation, testing alternative models for validation, and regular review and re-evaluation of the models.

The increase in forecast demand has potential implications for the timing of future capacity increases in the transmission system. At a national level, for example, the 2010 SOO maps forward by three to four years, an investment that the 2008 forecasts indicated was required by 2030.

The timing of the major grid upgrades approved over the past three years, including the NIGU, NAaA upgrade, and HVDC bipole, would have been largely unaffected had the revised forecasts been used. The prudent peak forecasts used for the assessment of the proposed investments are similar across the expected project completion dates.

Figure 6 shows the 80 per cent confidence limits in a graphical form to demonstrate the sensitivity of demand to uncertainty in the key drivers.

Figure 6 National energy forecast 80 per cent confidence limits



3.3 Forecasting regional energy demand

The limited availability of regional sectoral demand and key driver information severely restricts the options available for forecasting regional-level demand.

The approach adopted to date has been to allocate forecast national electricity demand to regions based on the key drivers that are available at a regional level. It would be preferable in the long term to more accurately model demand within the regions. However, this will only be possible once suitable data-collation processes have been established and in place for some time.

The approach used in preparing the 2010 SOO is to allocate residential demand based on regional population projections, and to allocate commercial and industrial demand based on regional GDP projections.

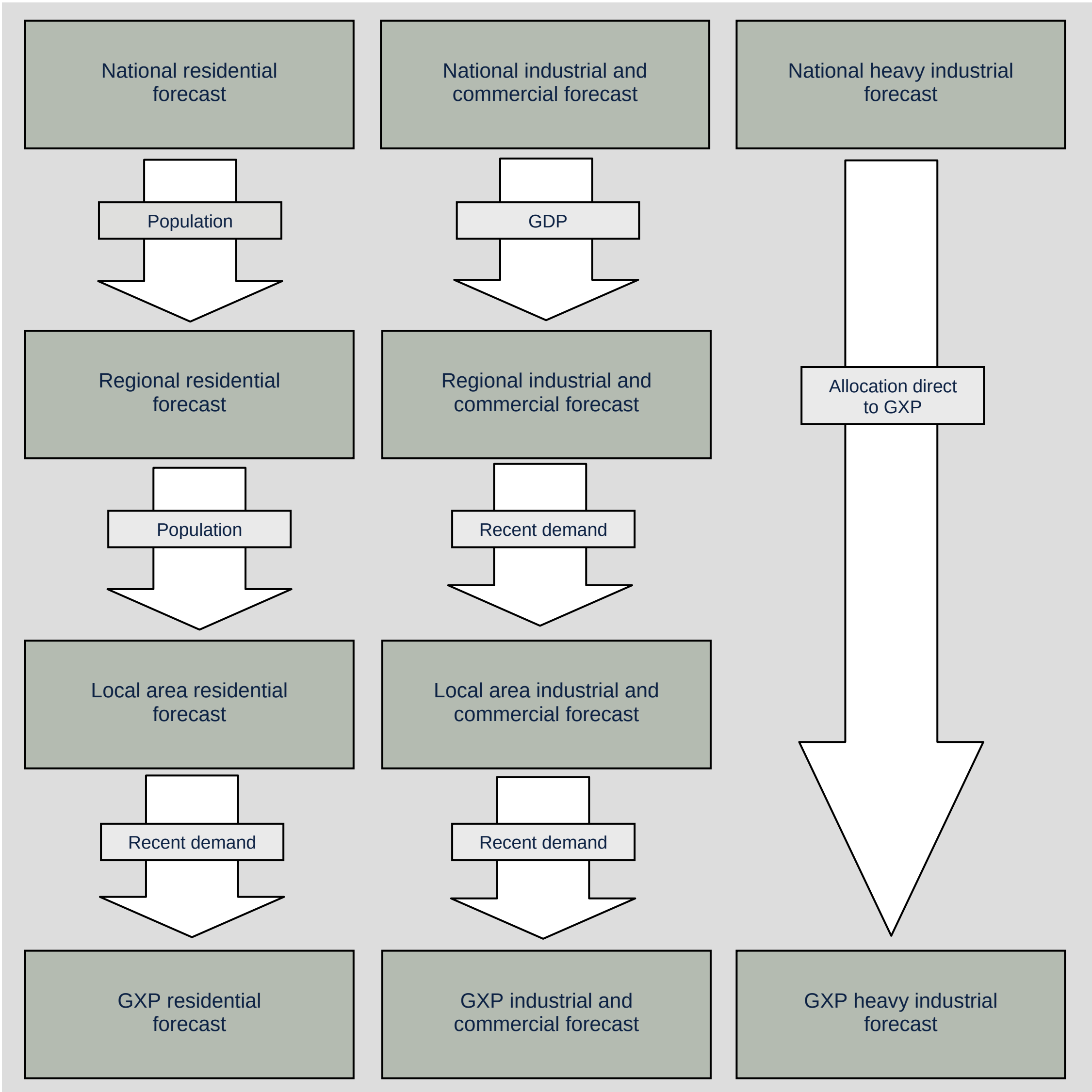
The regions used are determined by the configuration of the transmission grid rather than by regional council boundaries. In most areas there is no difference in this definition, but there are a small number of exceptions where GXPs are defined as being in regions different from those they are normally associated with.

A list of GXPs contained within each region is included as Appendix 4.

A breakdown of the current split of residential demand versus commercial and industrial demand at a regional level was obtained from electricity retailers. This was used as a starting point for forward projections based on changes in projected population and GDP.

GXP-level forecasts were calculated by allocating the various regional totals to the relevant GXPs. Population forecasts were available from SNZ at the old Electric Power Board level. The Electric Power Board areas are a useful level of aggregation as they provide an approximate grouping of demand that is supplied through each local area network. Residential demand was initially allocated to the Electric Power Board level based on forecast population for each area. This was then further allocated to individual GXPs based on recent demand. Commercial and industrial demand was allocated from the regional forecasts straight to GXP level based on recent demand. Figure 7 shows how demand in the three sectors was allocated.

Figure 7 Allocation process—from national to regional GXP by sector

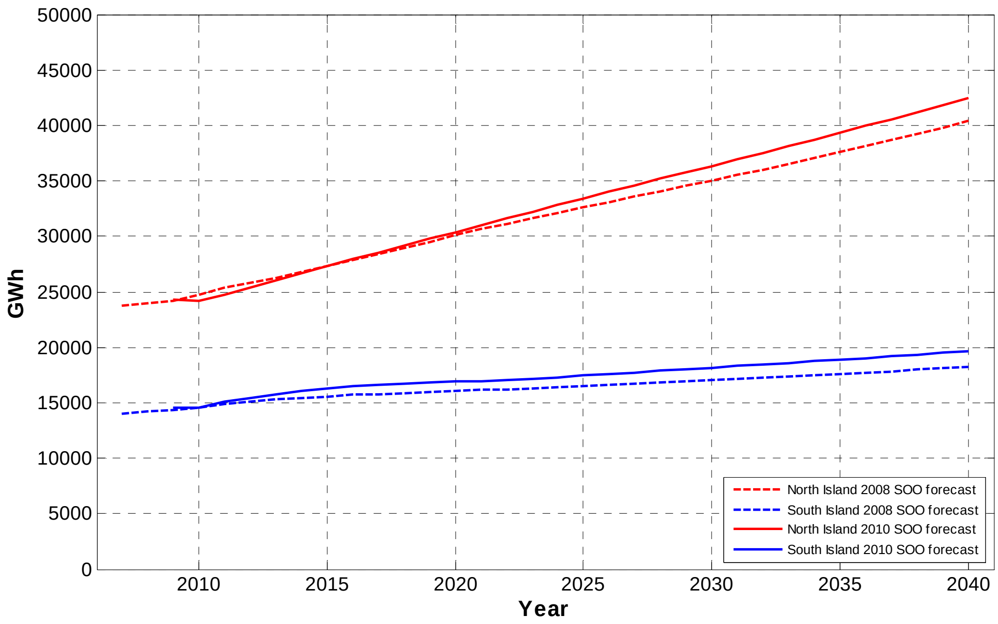


Some regions have experienced significant recent growth as a result of short-term changes in energy intensity in some industries. These changes would not necessarily be reflected in a simple allocation based on GDP or population. To capture the impact of the short-term trends, recent demand in each region has been extrapolated and used to allocate higher demand to those areas that have seen recent fast growth (and as a consequence, lower demand has been allocated to the lower growth areas).

The impact of the extrapolated growth in each region is weighted relative to the impact of the underlying GDP/population allocation, with the weighting reducing over time following a logistics curve.[29] The Tiwai aluminium smelter has been excluded from the calculation of the recent Otago/Southland trend.

The impact of the combined reduction in the national-level forecasts and the change in regional allocation is illustrated in Figure 8. It shows the relative balance of demand in the North Island and South Island in the new forecasts, compared with the allocation used in the 2008 SOO.

Figure 8 Island energy demand forecast



[29] Logistics curves are often used to describe the transition from one 'state' to another. The initial rate of change is approximately exponential, then as saturation begins, the rate of change slows and gradually stops.

Energy growth over the past ten years across most parts of the South Island has been high compared with the North Island, particularly in the West Coast and South Canterbury regions. This has mainly been driven by industrial growth on the West Coast, and dairying and irrigation growth in the lower and central parts of the South Island. This is reflected in the early years of the forecasts. Growth in later years is projected to slow in the South Island and increase in the North Island, consistent with projections of long-term regional population and GDP.

Growth in larger regions is normally more stable than growth in smaller areas because of the effect of load diversity. A greater mix of industrial loads and residential consumption means that large diversified regions are less subject to rapid changes in load resulting from changes in particular industries or consumer behaviour. Individual GXPs in particular can be subject to rapid growth over and above the regional and national average for an extended period of time.

COVEC has undertaken a number of studies of projected demand growth in individual regions over the past few years on behalf of Transpower. These have been published as part of the GUPs submitted by Transpower. The regions covered to date include Waitaki, West Coast and the lower South Island. The studies are based on line company forecasts combined with information gathered from individual consumers. The reports usefully highlight individual areas where rapid growth may occur, although care needs to be taken to allow for the effects of load diversity when considering the impact across multiple regions or areas.

An illustration of the potential for extended periods of high growth or sudden step changes in localised areas can be seen in historical consumption data. Average energy growth across the Otago/Southland region since 1997 (excluding the Tiwai point smelter) has been 1.9 per cent a year.[30] However, average growth at some individual GXPs within the region was much higher, with Naseby growing at an average of 13.2 per cent a year, Cromwell 7.9 per cent, Edendale 7.0 per cent, Studholme 5.4 per cent, and Frankton 4.5 per cent.

Regional GWh forecasts have been included in Appendix 5.

3.3.1 Regional uncertainty

Regional demand forecasts are subject to the same uncertainty as national demand forecasts, principally due to modelling error and input uncertainty

30 1997 was selected as the base year for comparing growth rates as it is the first whole calendar year following the establishment of the electricity market.

The range of national demand forecasts generated as part of the assessment of national level demand uncertainty has been allocated through to a regional level using the regional allocation methodology outlined above. Regional uncertainty also includes a component associated with inter-regional population changes relative to the SNZ– Electric Power Board-level forecasts. The resulting distribution of regional demand forecasts is used to calculate confidence limits for each region.

3.4 Forecasting peak demand

The GPA include forecasts of peak demand as well as the energy demand forecasts described above. Peak forecasts are important for transmission planning and investment decision-making.

Peak demand is defined for this purpose as the maximum of the average demand levels in all the half-hours ('trading periods') in a calendar year (as opposed to the highest instantaneous demand). Typically, demand peaks occur on weekdays in winter; they can occur either in the morning, often around 8am, or in the early evening. They are generally associated with cold weather events, during which domestic heating demand is high.

The methodology used for calculating the peak demand forecasts is designed to:

- incorporate information on recent trends in peak demand, ensuring that if a region has experienced rapid increase in peak demand over the last few years, the peak forecast continues to increase at a similar rate for the next few years; and
- provide a range of scenarios, from an 'expected' growth scenario with average demand growth, to a more conservative 'prudent' scenario with much higher, but still plausible, peak demand growth.

Two distinct sets of peak demand forecasts are included in this SOO.

- Prudent and expected peak forecasts
- After Diversity Maximum Demand peak (ADMD) forecasts

The prudent and expected peak forecasts are designed to show the range of plausible demand growth rates. The generation scenarios described in Section 7 of this document were developed using the 'expected' peak forecasts.

The ADMD forecasts were developed using both the 'expected' and 'prudent' peak forecasts. The ADMD forecasts use the growth rate of the 'prudent' forecast for the first five projected years, reflecting the need to plan transmission to serve high but plausible levels of demand growth in the near future. After the first five years, the ADMD forecast growth rate declines towards the growth rate of the 'expected' peak forecast, reflecting the reduced requirement for conservatism in the long term (since transmission plans can be adjusted in the future if demand growth is higher than expected).

As with the energy forecasts described in section 3.3, these forecasts are expressed at GXP level (including distribution but not transmission losses). They are net of embedded generation, ie they represent total electricity demand minus the output of New Zealand's embedded generators.

The forecasts make no explicit allowance for the possible impacts of increased demand-side response. In particular, the forecasts have not been revised downwards to model the probable benefits of increased load management or demand-side price response. These demand-side measures will be among the options for dealing with the demand peaks that are forecast, and should be modelled alongside supply-side measures.

The forecasts also make no explicit allowances for the impact of improved energy efficiency on energy consumption or peak demand. Energy efficiency has steadily improved during the historical period on which the forecasts are based, and is therefore captured in the forecast. It is expected that this trend will continue, but the forecast does not assume that the rate of improvement in energy efficiency will increase over the long term.

3.4.1 Prudent and expected peak forecasts

The prudent[31] and expected peak forecasts cover a range of possible growth projections. The expected forecasts represent an 'average growth' scenario; the prudent forecast incorporates higher growth rates and also considers year-to-year variation in peak demand.

Prudent and expected peak forecasts are also key inputs to the processes of producing Load Probability Curve (LPC) forecasts, ADMD forecasts, and generation scenarios, which, in turn, are important inputs to the GIT analysis.

Prudent and expected peak forecasts are produced at the regional, island, and national levels, and also on the 'half-island' level (Upper and Lower South Island, Upper and Lower North Island). While the energy forecasts presented in section 3.3 are additive over regions, the same does not apply to these peak forecasts. Owing to diversity of load, the joint peak forecast for each island will be slightly less than the sum of the regional peaks within that island, and the peak forecast for New Zealand will be less than the sum of the North and South Island peaks.

The peak forecasts are annual, representing the highest projected half-hourly demand occurring in a given calendar year, and cover the period from 2009 to 2049.

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31 Prudent demand forecasts are used to assess compliance with the *N*-1 safety standard.

The expected forecasts are calculated as projections of historical peak demand series. Predicted growth rates are driven in the short term (up to five years in the future) by projecting historical peak demand growth forward. In the longer term, peak demand growth is projected to proceed at the same rate as energy demand growth.

Demand growth in some regions is adjusted for known step changes at specific sites. For example, it is assumed that the electricity demand of the aluminium smelter at Tiwai will plateau at 610MW (demand at coincident peak), rather than continuing to grow as it has in recent years.

The prudent forecasts are based on a 10 per cent Probability of Exceedance (PoE) criterion. In other words, they are calculated as the 10th percentile of the probability distribution of future peak demand, allowing for various unpredictable factors that may influence demand growth. These factors include weather (high-demand peaks are closely correlated with cold temperatures), uncertainty about energy growth rates, and uncertainty about the relationship between peak and energy growth.

The prudent and expected peak forecasts (National, North Island, and South Island) are included in Appendix 6.

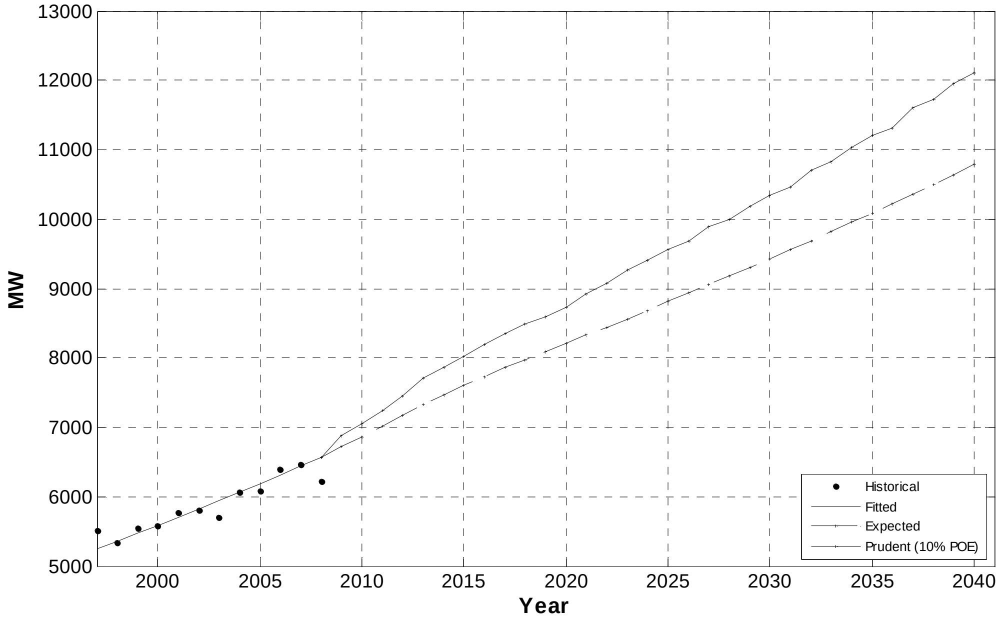
The expected forecast predicts approximately 2.1 per cent annual growth in national peak from 2009 to 2014, 1.5 per cent growth from 2014 to 2025, and 1.4 per cent from 2025 to 2040.

The prudent (P10)[32] forecast of national peak is initially 2 per cent—155MW—higher than the expected forecast and grows at a faster rate from that point onwards: 2.7 per cent from 2009 to 2014, 1.8 per cent from 2014 to 2025, and 1.6 per cent from 2025 to 2040.

The national expected and prudent peak forecasts are shown in Figure 9. These forecasts have also been produced separately for each island, and these are shown in Figure 10 and Figure 11 respectively.

32 P10 is shorthand for 10 per cent probability of exceedance. That is, there is a 10 per cent probability that the observed demand will be more than the forecast.

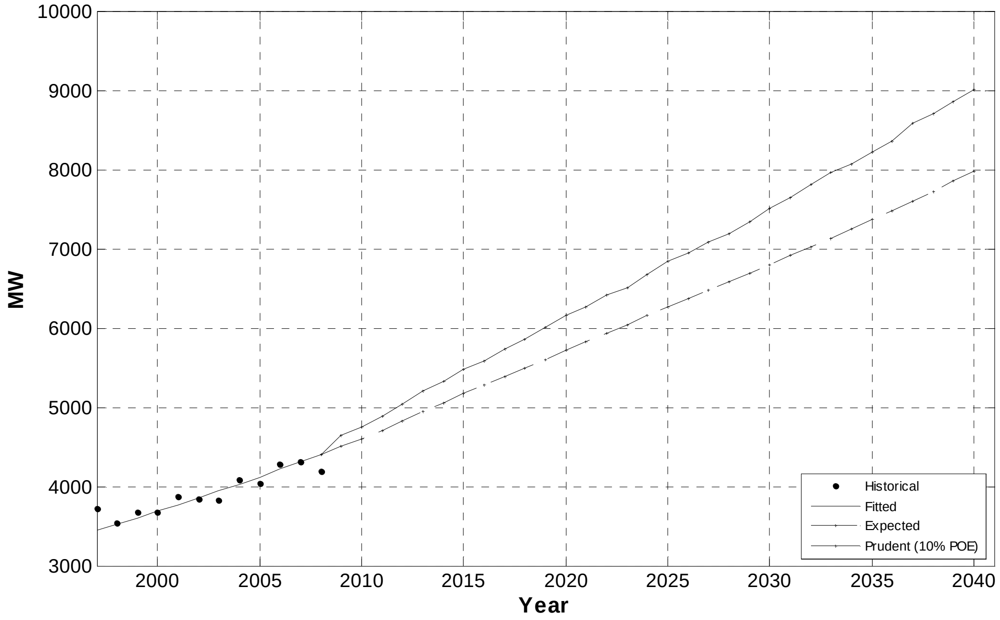
Figure 9 National peak demand forecast



For the North Island, the expected forecast is for approximately 2.3 per cent annual growth from 2009 to 2014, continuing at 2.0 per cent until 2025, and 1.6 per cent from 2025 to 2040.

The prudent (P10) forecast of North Island peak is initially 3 percent—135MW—higher than the expected forecast and grows at a faster rate from that point on: 2.8 per cent from 2009 to 2014, then 2.3 per cent until 2025, and 1.9 per cent from 2025 to 2040.

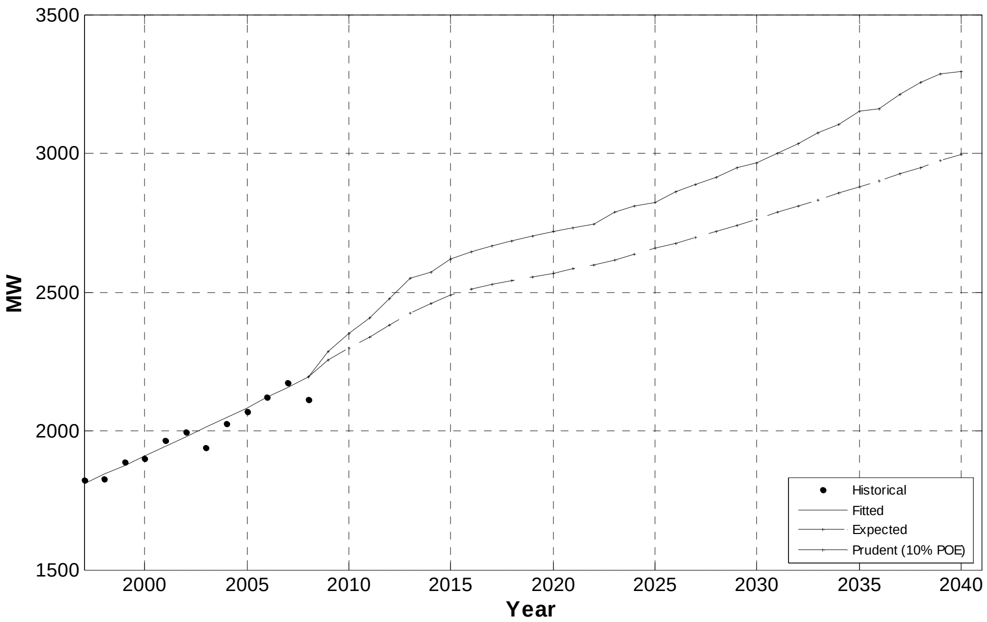
Figure 10 North Island peak demand forecast



South Island peak demand is expected to grow annually at 1.7 per cent from 2009 to 2014, down to 0.7 per cent from 2014 until 2025, and continuing at 0.8 per cent from 2025 to 2040.

The prudent (P10) forecast of South Island peak is initially just 1.3 per cent—30MW—higher than the expected forecast, growing at a faster rate from that point on: 2.4 per cent from 2009 to 2014, down to 0.8 per cent from 2014 until 2025, and continuing at 1.0 per cent from 2025 to 2040.

Figure 11 South Island peak demand forecast



In large part, peak demand is driven by weather conditions (cold temperatures on winter mornings and evenings lead to high heating load). The peak demand analysis in this document does not model weather effects explicitly. However, the Commission's medium-term demand forecasts for security of supply incorporate temperature effects, which show the connection between weather and peak demand.

A plot of 'temperature-adjusted peak demand' is included in the 2008 Security of Supply demand forecast report[33], and is reproduced here in a modified form (Figure 12). The effect of temperature on peak demand can be seen clearly.

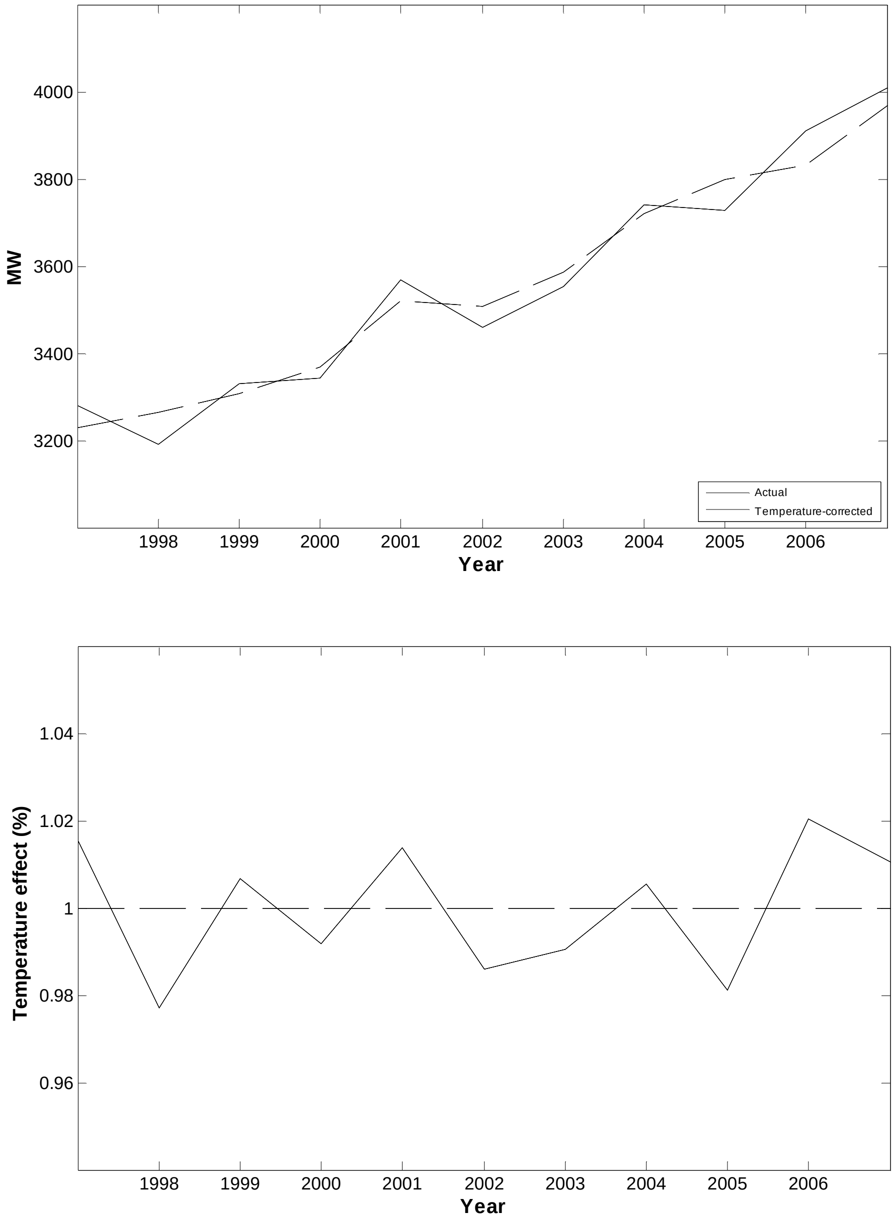
The temperature-adjusted peak demand graph shows that 2005 was a mild winter with relatively low peak demand, and that 2006, by contrast, was affected by a severe cold snap.

Information on demand trends in more recent winters can be found on the Commission's website.[34] The succession of cold fronts in May/June 2009, for instance, can be clearly seen in plots of peak demand data.

33 http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/security-demand/security-of-supply-medium-term-demand-forecast-in-2008.pdf

34 http://www.electricitycommission.govt.nz/opdev/secsupply/sos/overview/demand1/index.html

Figure 12 Effect of temperature on annual peak North Island 'residual' demand[35] 1997–2007



[35] 'Residual' demand refers to total electricity demand at GXP, minus demand of major industrial users, plus netted-off embedded generation. Half-hourly peak demand was used, as opposed to instantaneous peak. Hourly temperature data were sourced from MetService, expressed as population-weighted averages over various population centres. Temperature effects were estimated through regression analysis. See the 2008 Security of Supply demand forecast report for more details.

3.4.2 After diversity maximum demand peak forecasts

The ADMD peak forecasts are a key part of the GPA; they are the peak forecasts that are used in constructing consistent power-flow cases. An ADMD forecast can be viewed as representing a snapshot of a future high-demand state on the grid. The snapshot reflects the fact that the peak demands forecast for each GXP or region do not all occur simultaneously. Whereas a GXP or regional peak forecast may be useful for analysing connection assets, the ADMD forecast is more useful for analysing core grid loading. The ADMD forecasts are intended to incorporate an allowance for possible high peak growth over the next five years, while following an expected growth path beyond that time frame. They are constructed using the regional prudent and expected peak forecasts, with a number of additional adjustments applied. The process used to produce the ADMD peak forecasts is described below.

- The mean 2009 peak for each GXP is assessed using half-hourly meter data from 1997 to 2008. Starting peaks are based either on the GXP's peak trend over that period, or on a mean value if there is significant disruption or variation in the peaks at the GXP.
- Diversity factors, which relate the peak load at each GXP to the peak of the region containing the GXP, are calculated using 2007 calendar year data. The peak load for each GXP is projected forward using the regional energy forecasts—for the raw peak forecasts it is assumed that peak growth increases at the same rate as total energy growth. Projected raw regional peaks are then calculated by applying the diversity factors to the GXP projections.

The historical ratio between energy growth and peak growth has varied significantly between regions in New Zealand since 1997. The South Island as a whole has seen a lower rate of growth in peak demand (1.5 per cent a year) compared with the growth in energy (2.3 per cent a year). North Island peak growth (1.4 per cent a year) has been slightly higher than energy growth (1.3 per cent a year).

The following graphs show the average ratio of peak demand divided by mean demand for each region since 1997, and the change in ratio that has occurred in each region since 1997.

Figure 13 Average ratio of peak demand to mean demand by region

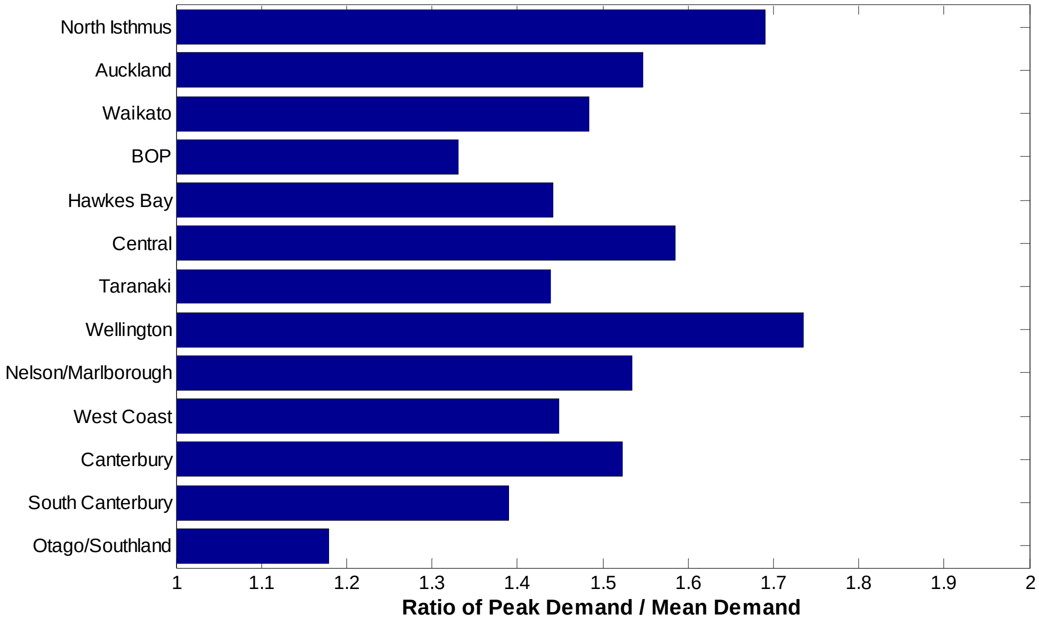
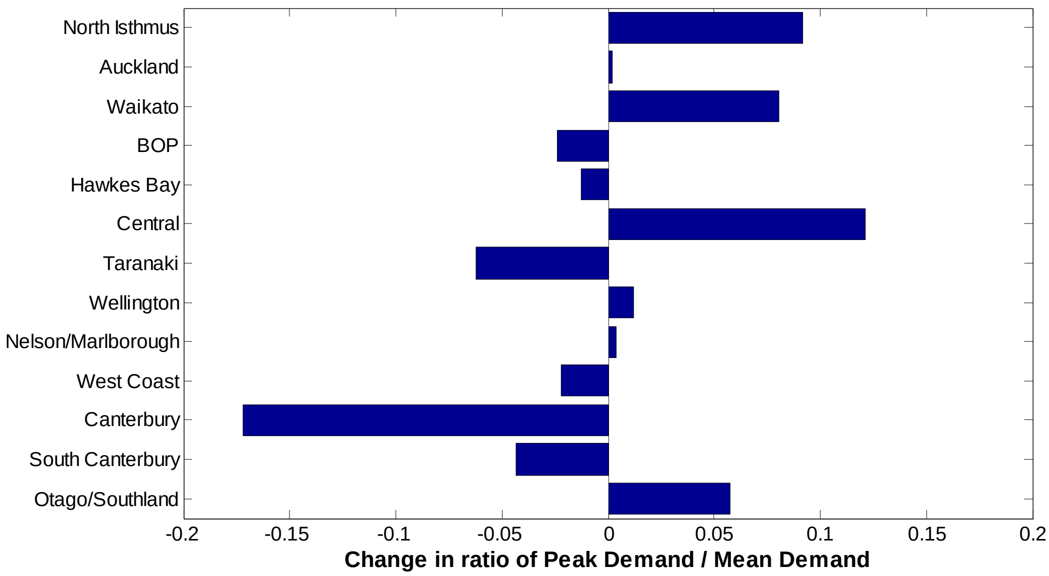


Figure 14 Change in ratio of peak demand to mean demand since 1997 by region



The relationship between peak and mean demand for each region varies slightly from year to year depending on a variety of factors, such as weather conditions and the response of large loads to electricity market price signals. Figure 14 shows that since 1997, the Central region has experienced the largest increase in peak demand relative to mean demand. Canterbury has experienced the greatest reduction in peak demand compared to mean demand.

The individual mean GXP forecasts are scaled so that the regional total peaks for the first five years of the forecasts (after adjustment for the diversity factors) match back to the 10 per cent PoE region forecasts. For the sixth and subsequent years the forecasts are scaled by the same proportion used in year five. This ensures that shorter-term variation in peaks is included within the time frame required for committing new transmission build, without over-inflating the peak projections used for long-term planning.

Two minor additional adjustments are then made to the resulting peak projections to produce the ADMD forecasts.

- To allow for the impact of generating plant embedded in the local line company networks, the peak forecasts are increased slightly to incorporate potential growth in demand 'hidden' behind GXPs by embedded generation.
- Additional peak-load adjustments are also made in regions where identified 'committed' new load represents a significant proportion of the existing regional load. A total of 14MW of committed new load has been identified in the West Coast region and 10MW additional load at the Black Point GXP in the Waitaki area. In the Taranaki region 10MW of new load has been included and an additional 10 MW at the Tiwai Aluminium Smelter. The new loads are expected to come online between 2010 and 2011 and have been added directly to the peak forecasts.

The ADMD peak forecasts presented in this document (see Appendix 1) are the regional loads at the time of island peak as used in the PSA. The individual peaks projected for each region are slightly higher.

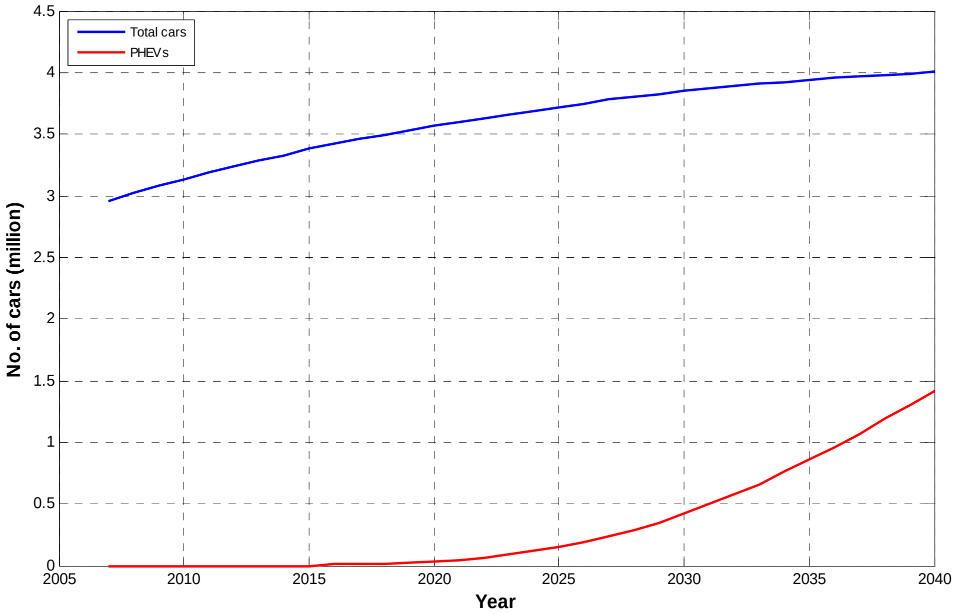
3.5 Demand scenarios

3.5.1 Plug-in hybrid electric vehicles demand forecast

Due to the typically short daily commuting distance in New Zealand, the electricity demand of either plug-in hybrid electric vehicles or electric vehicles would be very similar (ie most trips for plug-in hybrid electric vehicles would be fully electric). Consequently, the term 'electric vehicle' is used loosely to refer to electric vehicles, plug-in hybrid electric vehicles, and fuel cell vehicles.

Electric vehicle demand has been modelled as an additional component of demand, added to the base forecast in two of the five scenarios: the 2010 Sustainable path and 2010 Coal scenarios.[36] The electric vehicle demand forecast is based substantially on an electric vehicle penetration scenario developed by the Ministry of Transport (MoT), using its vehicle fleet emissions model. The vehicle fleet emissions model produces a projection of total number of vehicles of different types (Figure 15), and total vehicle kilometres travelled.

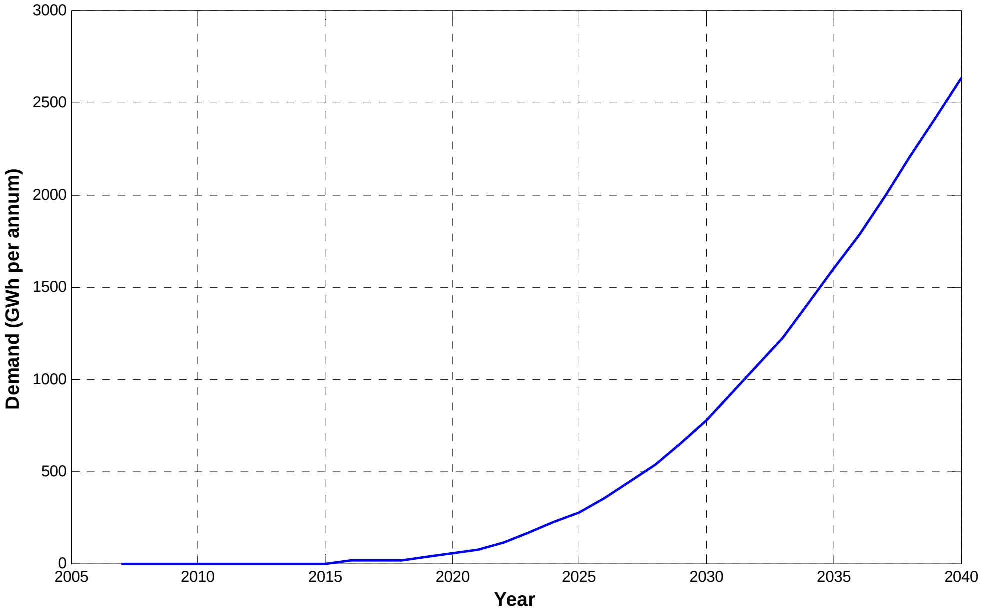
Figure 15 Fleet composition



Additionally, MoT provided trip distance data from the Household Travel Survey. Assuming a pro rata allocation of vehicle kilometres travelled to the total electric vehicle fleet, an assumed electric vehicle daily range, and energy consumption per vehicle kilometres travelled, a simple calculation yields the electric vehicle energy demand, in GWh a year. Data from the Household Travel Survey also enables an allocation of electric vehicle demand on a regional basis. The resulting electric vehicle energy demand forecast is illustrated in Figure 16.

36 Refer to section 7 for discussion of these and the other scenarios developed for the 2010 SOO.

Figure 16 Electric vehicle demand forecast



There are a number of options for recharging electric vehicles. For instance, they can be charged overnight ('off-peak'), or the load can be spread over the entire 24 hours of the day ('anytime'). Ultimately electric vehicles are likely to be charged off-peak, with some ability to shift the charging time in response to price or other supply-side constraints. It is possible that electric vehicles will participate in balancing intermittent generation (through smart metering and vehicle-to-grid or vehicle-to-house technology), and may enable a greater penetration of wind generation into the electricity system.

For now, a mostly off-peak charging profile has been assumed, with some small contribution during peak demand periods. In the 2010 Coal scenario, electric vehicles were also modelled as a price-responsive curtailment, to mimic the vehicle-to-grid technology.

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4. Overview of the scenarios and the development approach

This section describes the approach adopted for the development of the GPA, and provides a brief description of the scenarios arising from the GPA. There is also a brief discussion of GEM.

4.1 Approach to GPA development

4.1.1 Overview

The GPA are required to contain, among other things, 'committed projects for additional generation…'[37] and 'a reasonable range of credible future, high-level generation scenarios…'.[38]

Summaries of the scenarios arising from the GPA are in Table 1.

Scenario techniques are typically adopted if the range of plausible future uncertainties is sufficiently wide that decision-making or planning outcomes would be markedly different under different states. Projecting transmission requirements over the economic lifetime of generation and transmission assets would appear to be such a situation. The approach generally involves developing a set of scenarios intended to encompass a credible range of future uncertainties.

The scenario development process has three main steps.

- Assemble input data, including information on existing, committed, and future generation, and also on fuel price projections, carbon charges, economic factors, aspects of the transmission system, demand-side participation, etc.
- Develop the scenario 'stories', ie identify the key drivers and assumptions (for example, fuel cost, fuel availability, and carbon price) that shape the future development paths in the scenarios, and determine which internally consistent combination of drivers will apply in each scenario.
- Run the models to develop each generation scenario.

This process is illustrated in Figure 17.

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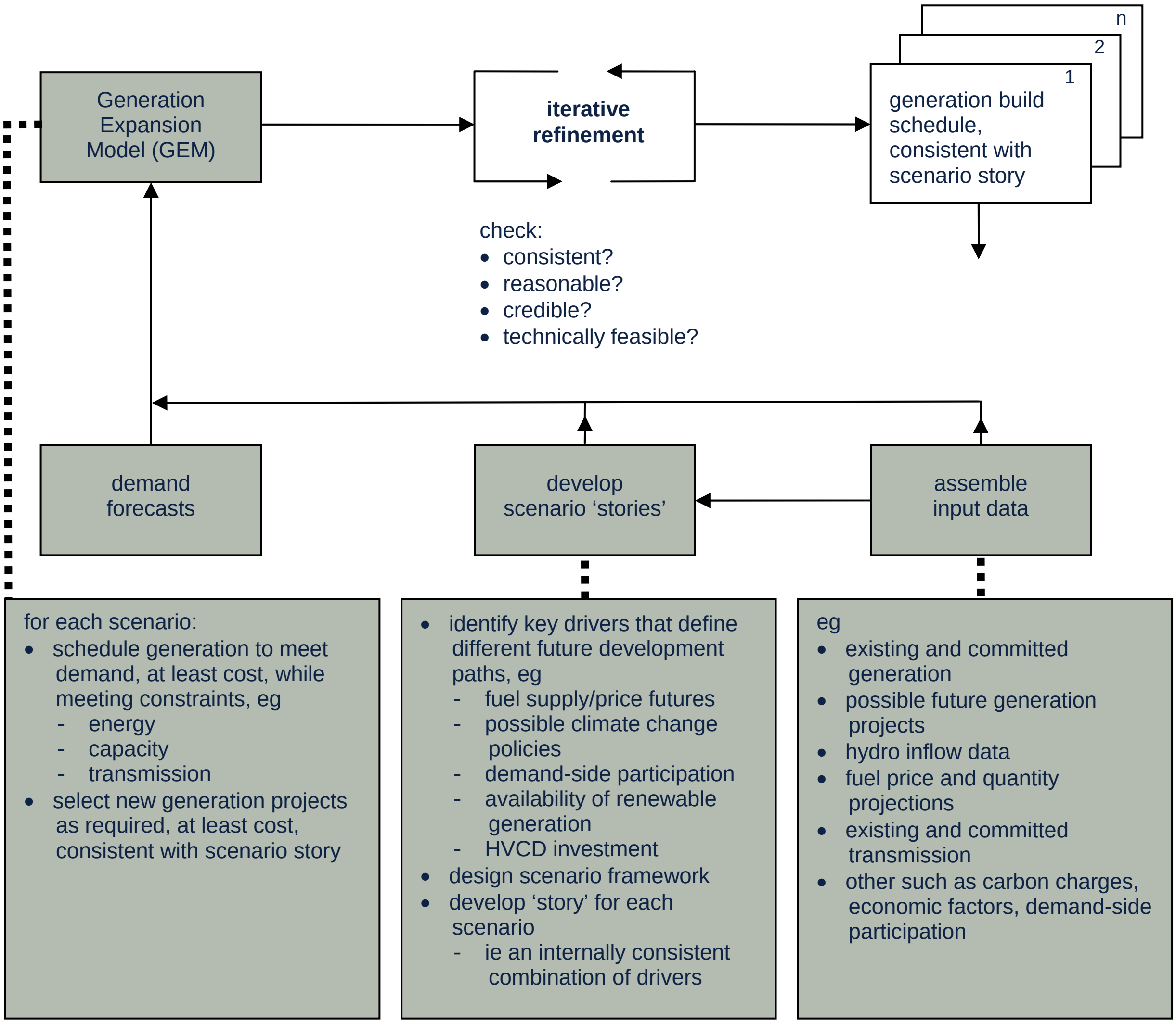
[37] Rule 10.3.1.1 of section III of part F.

[38] Rule 10.3.1.3 of section III of part F.

Figure 17 Scenario development process



It should be noted that the modelling approach is not output-driven, ie the input assumptions have not been chosen to deliver a predetermined outcome (such as a certain quantity of generation build at a particular time and location). Rather, the SOO uses a model that dynamically schedules generation build based on underlying input drivers that have been constructed on an internally consistent basis.

Input assumptions have been chosen to cover a reasonable range of possible values, with regard to the level of uncertainty involved, rather than to yield specific outcomes.

These steps are repeated, in a process of iterative refinement, until the scenarios are reasonable, credible, technically feasible, suitable for PSA, and an accurate reflection of the stories they are intended to depict.

Stakeholders can reproduce the scenarios by downloading the GEM model[39] and running it to generate build schedules. This allows interested parties to investigate how the end results will be affected by varying any of the assumption.

4.1.2 Reviewing inputs, assumptions, and the scenario framework

The Commission prepared and published information on committed and possible future generation projects in September 2009, in the lead-up to preparation of the 2010 SOO. The information was compiled following discussions with stakeholders and consideration of specialist reports commissioned from generation experts.

In particular, this work involved:

- updating input data in response to announcements by participants and reviewing industry publications, such as annual reports and energy-outlook papers;
- updating the CDS factual and historical information on the transmission system, nodal prices, bids and offers, demand and generation information; and
- exploring with stakeholders possible future generating projects, fuel supply and cost projections, major maintenance programmes, and other relevant information.

4.1.3 Developing the scenario 'stories'

Preparations for developing the stories included:

- reviewing experience from recent consideration of Transpower investment proposals;
- reviewing the approach adopted by other parties, such as MED, in developing a scenario framework and/or development methodology;
- exploring possible modelling methodologies and scenario development techniques;
- considering the energy policy context, likely drivers of future supply and demand, and key uncertainties; and

39 The GEM model can be downloaded at: http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html

- obtaining input from stakeholders regarding key uncertainties and design of the scenario framework.

The output of this work was a scenario framework based around fuel supply/price futures coupled with possible climate change policies. The key drivers adopted were carbon price, renewables preference, availability of renewable generation, fuel availability and cost, penetration of the plug-in hybrid electric vehicle into the vehicle fleet, status of the Tiwai smelter, and the extent of demand-side participation.

These drivers were chosen on the basis that they were:

- uncertain;
- material to generation and transmission development; and
- quantifiable

The drivers were varied across scenarios. Where possible, the combinations of drivers within each scenario remain consistent. However, in many cases the association of the two factors within a scenario is simply the result of a need to include many factors in just five scenarios, rather than an assertion that the two factors are causally connected.

4.1.4 Generation Expansion Model overview

GEM is a long-term capacity planning model. Its key purpose is to systematically sift through a large amount of information and produce internally consistent, least-cost 'build schedules' for new generation plant. A build schedule is simply a chronological list of new plant that the model anticipates will be installed. One such build schedule is generated for each of the scenarios considered.

GEM was purpose-built for the Commission, with the development work initiated in 2006. Generation scenarios were defined by economic drivers, and an analytical tool was required to capture the effect of these drivers on plant mix, while also capturing hydrological variation and security of supply over long and short time frames. Since 2006, GEM has been further developed in a number of areas related to model implementation and system representation.[40]

[40] The GEM computer codes, as used for the 2010 SOO, together with the input data files and associated documentation, are available for download from the Commission's website at: http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html

Technically, the core of GEM is the canonical capacity expansion problem formulated as an MIP problem. The computer code is written using the GAMS[41] optimisation software and the model is solved with CPLEX, a commercial MIP solver accessed via the GAMS CPLEX[42] interface. The model's input data is compiled as a series of thematic worksheets in an Excel spreadsheet. Model outputs are written to spreadsheet-compatible files, allowing further processing and/or plotting using software such as Matlab.

In determining the least-cost build schedule, GEM is required to satisfy certain conditions, or constraints. The constraints relate to economic, physical, and technical features of the New Zealand electricity system. While GEM has been constructed as a flexible modelling tool, the specific configuration used to produce the build schedules for the GPA includes the following key features.

- The model seeks to minimise capital expenditure on new and refurbished generation plant and transmission investments, fixed and variable operating costs for all generation plant, and HVDC charges. Variable costs include operating and maintenance costs, carbon charges, fuel costs, and, where applicable, carbon sequestration costs.
- All load and generation is aggregated up to a two-node representation of the network, the North and South Islands.
- Inter-island transfers over the HVDC link are modelled explicitly, as are transmission losses on the HVDC link.
- Annual energy demand is modelled using nine-block quarterly Load Duration Curves (LDCs), one per island.
- Peak demand in each island is modelled by a set of five capacity constraints. In each modelled year, these constraints require peak demand to be met by committed and new projects, given assumptions about their availability at peak, as well as various contingent events related to network security.
- Variability of hydro inflows is modelled by GEM scheduling quarterly hydro generation quantities over the relevant load blocks, subject to minimum and maximum capacity factors (to reflect, for example, must-run releases in off-peak periods).

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41 GAMS.

42 CPLEX is a commercial solver.

- Capacity expansion plans (build schedules) are determined according to the weighted average system operation costs over five hydro inflow sequences, reflecting historical hydrological variation.
- Recently approved upgrades to the HVDC link are programmed to occur in 2012 and 2014, respectively.
- Perfect competition in the wholesale electricity market is assumed.
- Existing thermal plants are required to be either refurbished or retired upon reaching the end of their economic lives. The refurbish/retire decision is endogenous to the model and is driven by the relevant costs—capital, fuel, CO_2 taxes, etc—in each scenario.
- GEM determines an optimal, least-cost solution given the assumptions, eg the costs it is presented with. However, it is also possible for users to 'instruct' GEM to undertake certain actions regardless of the underlying economics. For example, in order to reflect the ease of consenting in some parts of the country relative to others, some new plants are forced into the solution in some scenarios (see Appendix 7).
- Ancillary services are not fully represented in GEM at the present time. While some of these services are currently modelled within the context of the capacity constraints, the energy side of the model largely ignores ancillary services. A comprehensive treatment of a range of ancillary services in GEM is currently being developed.
- Work is also underway to better represent the impacts of intermittent generation.

Many of the constraints modelled in GEM are simplifications of more complex issues that cannot be modelled in their entirety in a long-term expansion model. A good example is the constraint that no more than 20 per cent of the energy produced in a year can be sourced from wind generation.[43] This constraint is designed to reflect a rule-of-thumb limit to wind integration. In reality the limit to wind integration will be set by economic trade-offs, for example the cost of providing balancing generation and fast reserves. These wind issues have not been fully analysed and it is likely that under some circumstances the model would decide to introduce far more wind generation than currently is the case. This would occur in high carbon price scenarios, perhaps with some reduction in wind farm capital costs, resulting from further experience with the technology.

43 The rationale for the 20 per cent figure is discussed further in section 6.2.3.

The treatment of security constraints in GEM is relatively simplistic. These constraints operate at an island-wide level, to ensure that adequate plant is available in each island to meet peak demand under various contingencies and scenarios. These constraints may lead the model to build plant in an export-constrained region within the island that could not contribute to meeting the island peak.

As noted, GEM endogenously makes a decision whether to refurbish or retire an existing thermal plant when it reaches the end of its economic life. This aspect of GEM does not represent a sophisticated economic trade-off between increasing Operating and Maintenance (O&M) expenses as the plant ages and the capital cost of a similar, albeit contemporary vintage, new plant. Rather, GEM is configured to make the refurbishment/retirement decision in a single user-specified year, ie at the end of the plant's economic life, and only in the case of selected existing thermal plant. In the case where the decision is to retire, then the plant remains available for some user-specified number of years following the decision date, eg three years. It is then shut down at zero cost. Conversely, if the decision is made to refurbish, then at some user-specified, annualised capital cost, the refurbishment will take place and the plant remains available for the remainder of the modelled horizon. No other operating parameters, eg nameplate capacity or heat rate, are assumed to change following refurbishment.

Although the endogenous retirement/refurbishment decision is not as sophisticated as other computationally more expensive formulations might be, it nevertheless enables an element of economics to drive retirement decisions. This is preferable to always exogenously specifying that certain plant will be removed from service at some given point in time, regardless of the economic drivers.

Of course, the retirement/refurbishment decision is taken in GEM assuming perfect foresight, as are all other GEM decisions. In other words, uncertainty regarding future costs, for example, is not treated stochastically. In reality, firms are likely to behave more conservatively than a perfect foresight model would. For this reason, in some cases we still choose to exogenously decommission plant in some scenarios so as to not have the same pattern of retirements and refurbishments in all scenarios.

It is a general principle that long-term models such as GEM must be checked or calibrated by more detailed short-term models. The Commission checks many aspects of the build plans produced by GEM using PSA and short-term market modelling.

A particular criticism that could be levelled at GEM is that it models a least-cost expansion as opposed to a market-based expansion. However, market share and plant ownership assumptions to enable a market-based expansion would become quite arbitrary over the long time periods being modelled. Assuming the market approaches a competitive outcome, it is expected that at the high-level view of the industry provided by GEM, the broad features will be reasonably informative and less controversial than could be provided by a market simulation over such long time periods.

Another valid critique of GEM is its determinism. The model has perfect knowledge about the future, within each scenario. Thus the decisions made by GEM do not conform to the risk-honed decisions made by an investor with very incomplete future knowledge. This deficiency is not alleviated by solving GEM for a number of future scenarios that span the uncertainty, as within each scenario the model sees a single definite future. It has been suggested that applying more sophisticated techniques, such as Stochastic Dual Dynamic Programming, would be better.

The Commission considers such models would not be practical. A better approach is hinted at in the way the model is currently solved with five possible hydrologies, representing a range from wet to dry inflow sequences. This approach could be extended to co-optimise the model over a range of other uncertainties, such as carbon price or gas discovery.

This type of approach is reasonable, since investors are probably worried only about discrete possible future states. By relaxing other aspects of the model, the increased difficulty of co-optimising over a number of possible discrete futures should still be feasible numerically. We expect that this type of model would replicate more closely the market decisions to invest in renewables, for example, in response to the possibility that the carbon price could go very high and that gas supplies would be low.

4.2 The five scenarios

4.2.1 Scenario outlines

A brief description of each of the scenarios is included in Table 4. These form the core of the supply-side of the GPA.

Table 4 Scenario outlines

Scenario	Description
2010 Sustainable path	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction with a long-term average carbon charge of $60/t. In addition, no new large gas discoveries are made in the future. The resultant high gas price makes gas-fired baseload generation relatively uneconomic to run and forces some to be decommissioned. Renewable generation, including hydro, wind, and geothermal, backed by thermal peakers for security of supply, are the least-cost option under this scenario. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. New energy sources are brought on stream in the late 2020s and 2030s, including biomass, marine, solar, and carbon capture and storage. Demand-side participation becomes a more important feature of the market, driven by consumer pressure.
2010 SI wind	Wind development proceeds at a slightly more rapid pace than in 2010 Sustainable path. The major wind farms having or currently seeking resource consent are built in the lower South Island in the early years. As with the 2010 Sustainable path, a high carbon charge and gas price lead to the decommissioning of some thermal plants. These plants are replaced by renewable generation. Thermal peakers supplement renewable development. New technologies are available after 2020. Less geothermal generation is available to this scenario because of resource consenting issues.
2010 Medium renewables	A 'middle-of-the-road' scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. The lead time between gas discovery and production leads to gas shortage between 2020 and 2030. Tiwai smelter is decommissioned in the mid-2020s.
2010 Coal	The assumed low carbon charge and greater gas availability after 2030 make new gas-, coal-, and lignite-fired plants economic. Geothermal resources are still the least-cost option, with all the high-temperature resources developed prior to 2025. Little new hydro can be consented and some existing hydro schemes have to reduce their output, owing to difficulty in securing water rights. Electric vehicle uptake is relatively rapid after 2020.
2010 High gas discovery	Major new gas discoveries keep gas prices low over the entire time horizon. Some existing thermal power stations are replaced by new, more efficient gas-fired plants. New CCGTs and gas-fired peakers are built to meet the country's power needs; the most cost-effective renewables are also developed. The demand-side remains relatively uninvolved.

4.2.2 Scenario weighting

The weightings of the scenarios for this SOO have been given careful consideration and the conclusion is that the five scenarios should all be assigned equal weight.

Table 5 Scenario weightings

Scenario name	Weighting
2010 Sustainable path	20%
2010 SI wind	20%
2010 Medium renewables	20%
2010 Coal	20%
2010 High gas discovery	20%

5. Electricity generation

5.1 Types of generation

The types of large-scale electricity generation relevant to the New Zealand market are summarised in Table 6. The table also includes some demand-side measures, which can supply services to the power system in a similar way to generation.

Table 6 Types of generation

Generation type	Fuel	Comment
Non-fossil-fuelled	Geothermal	Geothermal generation is focused on the geothermal steam fields in the central North Island, although there are smaller fields elsewhere such as in Northland. Currently it contributes around six per cent of total installed capacity, but this is expected to increase in the next decade.
	Wind	Wind energy currently provides only about five per cent of total installed capacity. However, many new wind farms are at various stages of the planning and construction processes, and this technology is expected to make an important contribution to supply over the next few years.
	Hydro	Hydro generation currently accounts for approximately 57 per cent of total installed capacity. There are major hydro systems in both the North and South Islands, together with a number of smaller systems and individual stations scattered around the country.
	Other renewables	Other renewable forms of generation include (but are not limited to) pumped hydro, wave generation, tidal generation, landfill gas, biogas, photovoltaic (solar), and biomass-fired generation. Their current contribution to national electricity supply is relatively small, but some of them may play a more important role in future.
Fossil-fuelled	Gas	Gas-fuelled plant currently provides about 15 per cent of total installed capacity. Major gas-fired generators are located in Taranaki, Waikato, and Auckland, following the route of the gas transmission system.
	Coal	Coal-fuelled plant currently provides about 11 per cent of total installed capacity. Currently the main coal-fired generation is at Huntly Power Station. While Huntly burns 'black coal',[44] sourced both from local supplies and imports, the South's vast lignite[45] resources provide a potential alternative source of fuel.

[44] Black coal is defined as a higher grade coal with low sulphur and ash.

[45] Lignite is a low-grade coal often referred to as brown coal. It has a lower calorific value than black coal.

Generation type	Fuel	Comment
	Diesel	The Whirinaki power station is currently being operated on diesel. It plays an important role in national security of supply. More diesel-fired generation may be constructed in future.
	CCS	In future, it may be possible to construct coal- or gas-fired plant with 'carbon capture and storage'. This technology could be used to store the greenhouse gases produced, rather than releasing them into the atmosphere.
Demand-side[46]	Interruptible Load (IL)	IL is demand that can be quickly disconnected by a central agency, for example, ripple-controlled water heating. Participation in IL provision is voluntary and is compensated for. IL already plays an important part in system security, and this role is expected to increase. Other Commission work programmes are currently working on promoting load management and removing barriers to its development.
	Demand-side management	Demand-side management refers to voluntary load reductions in response to price, and will be supported by a range of initiatives including demand-side bidding, smart metering, time-of-use pricing, and/or demand-side aggregation. The role of demand-side management in promoting system security is expected to increase over time.

5.2 Approach to information gathering

A key component of the GPAs is the Commission's view of the reasonable range of credible future generation scenarios.[47]

A two-stage approach was adopted to develop these projections. First, a list of existing, committed, and potential future generation projects was collated. Generation scenarios were produced by selecting projects from this list, using GEM.

This section describes how the list of potential generation projects was developed. Generation is broken into three categories and described further in the following sections.

- Existing generation
- Committed projects

[46] Demand-side response is treated as a potential 'generator' and is part of the list of modelled projects. Its features refer to options for reducing electricity demand. Some demand-side measures are included here because they can potentially be used to reduce the need for new generation.

[47] Rule 10.3.1.3 of section III of part F.

- Other possible future projects (these are called generation opportunities, but may eventually become 'modelled projects' in the analysis of a particular investment proposal)

The last of these is further broken down into:

- 'near-future generation' consisting of projects that are highly likely in the first few years of the scenarios; and
- 'prospective projects' that vary widely in terms of their nature, timing, and status.

All the projects listed have a capacity of at least 10MW. [48] Distributed generation has not been included in the GPA and the generation lists. Distributed generation, which is the collective term for relatively small generators, is an important part of New Zealand's generation portfolio and should therefore arguably be included in the Commission's analysis. It may also grow at a faster rate than previously experienced due to the impact of the Distributed Generation Regulations and the impact of the regional coincident peak demand allocation method for allocating interconnection charges. However, the Commission has not included distributed generation in its analysis because:

- distributed generation imposes relatively few additional transmission requirements, because it is sited close to load; and
- progressive increases in the amount of available distributed generation are effectively built into the SOO's demand forecasts, which implicitly assume that the amount of available distributed generation will continue to grow at historical rates.

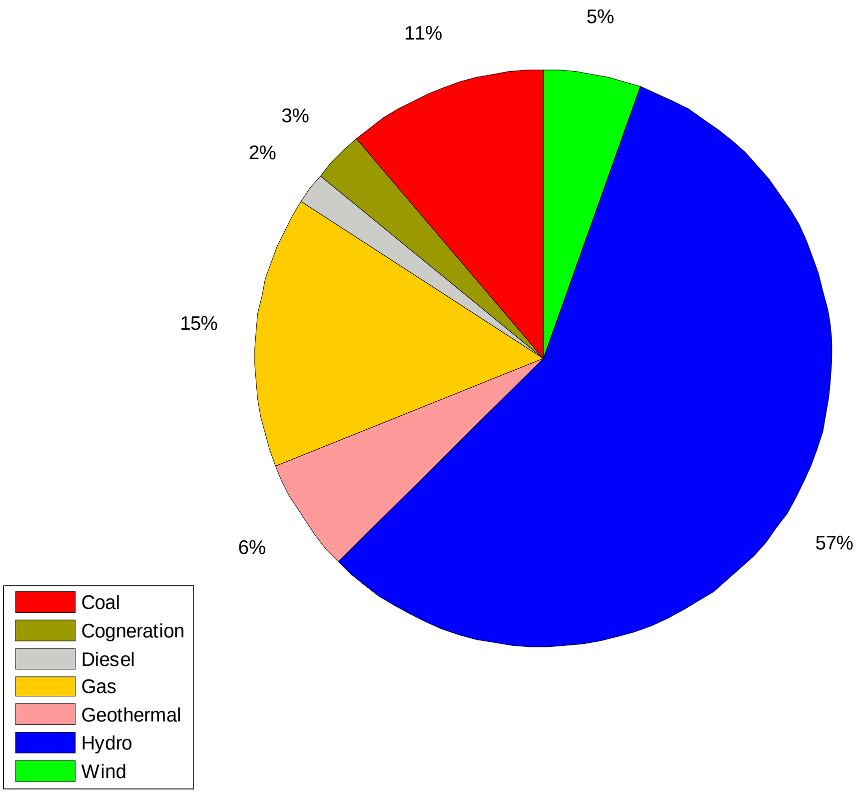
5.3 Existing generation

New Zealand's electricity consumption is primarily met through a mix of hydro, thermal, geothermal, and wind generation. Approximately 95 per cent of electricity generated is produced by plant directly connected to the transmission grid. The remainder is either embedded within the local lines networks—either associated with a load or operating independently—or serves load that is not connected to the national electricity network.

Hydro remains the predominant source of generation, contributing around 57 per cent of the total capacity. Thermal is around 31 per cent of total generation and geothermal six per cent. Wind currently contributes around five per cent but is expanding quickly compared with the existing installed base, with significant new capacity recently commissioned or under construction. Figure 18 shows the breakdown of generation by fuel type.

48 Apart from some small hydro schemes of less than 10MW.

Figure 18 Existing capacity by fuel type



Data on existing plant was obtained from a number of sources including asset capability statements, generating company corporate reports, market data, and security of supply generator returns.

The type, location, and size of existing generation connected to the transmission grid are shown in the following table.

Table 7 Existing grid-connected generation

Name	Type	MW	Region
Bay of Plenty Hydro	Hydro	145	Bay of Plenty
Bunnythorpe Hydro	Hydro	303	Central
Christchurch Hydro	Hydro	62	Canterbury
Clutha Hydro	Hydro	720	Otago/Southland
Deep Stream Hydro	Hydro	3	Otago/Southland

Name	Type	MW	Region
Fiordland Hydro	Hydro	775	Otago/Southland
Glenbrook	Co-generation	74	Auckland
Hawera	Co-generation	70	Taranaki
Hawkes Bay Hydro	Hydro	133	Hawkes Bay
Huntly Coal Unit 1	Thermal	250	Waikato
Huntly Coal Unit 2	Thermal	250	Waikato
Huntly Coal Unit 3	Thermal	250	Waikato
Huntly Coal Unit 4	Thermal	250	Waikato
Huntly unit 5 (e3p)	Thermal	385	Waikato
Huntly unit 6 (P40)	Thermal	50	Waikato
Kapuni	Co-generation	25	Taranaki
Kawerau Stage 1	Geothermal	90	Bay of Plenty
Kinleith	Co-generation	40	Waikato
Mokai	Geothermal	115	Waikato
Nelson/Marlborough Hydro	Hydro	40	Nelson/Marlborough
Nga Awa Purua	Geothermal	130	Waikato
Ngawha	Geothermal	25	Auckland
Ohaaki	Geothermal	69	Waikato
Otahuhu B	Thermal	380	Auckland
Poihipi	Geothermal	53	Waikato
Rotokawa	Geothermal	34	Waikato
Southdown	Thermal	122	Auckland
Southdown E105	Thermal	45	Auckland
Taranaki CC	Thermal	380	Taranaki
Taranaki Hydro	Hydro	24	Taranaki
Tararua 3	Wind	93	Central
Tararua Wind 1 and 2	Wind	68	Central
Tauhara	Geothermal	20	Waikato
Te Apiti	Wind	90	Central

Name	Type	MW	Region
Te Rapa	Co-generation	44	Waikato
Te Rere Hau 1 and 2	Wind	17	Central
Te Rere Hau 3	Wind	17	Central
Waikato Hydro	Hydro	1104	Waikato
Waipori Hydro	Hydro	50	Otago/Southland
Wairakei	Geothermal	163	Waikato
Wairakei Binary	Geothermal	14	Waikato
Waitaki Hydro	Hydro	1700	Otago/Southland
Wellington Hydro	Hydro	32	Central
West Wind	Wind	143	Wellington
Whirinaki	Thermal	155	Hawkes Bay
White Hill	Wind	58	Otago/Southland
Total		**8,910**	

5.4 Committed generation projects

A generation project is treated as a 'committed project' if it is reasonably likely to proceed and all of the following are satisfied.[49]

- All necessary resource planning and construction consents, approvals, and licences have been obtained and any other regulatory requirements have been fulfilled.
- Construction has commenced or a firm commencement date has been set.
- Arrangements for securing the required land are in place.
- Supply and construction contracts for plant and equipment have been executed
- Financing arrangements are in place.

The committed generation projects are set out in Table 8.

[49] See clause 21 of the GIT.

Table 8 Committed generation projects

Year	Name	Type	Owner	Island	NameplateMW
2010	Stratford Peaker	Thermal	Contact Energy	North	200
2011	Te Rere Hau 4	Wind	NZ Windfarms	North	15
2011	Te Uku	Wind	Meridian Energy	North	64
2012	South Island Peak[50]	Hydro	Meridian Energy	South	85
2013	Te Mihi[51]	Geothermal	Contact Energy	North	160

There is also a range of committed transmission projects that have been included in all scenarios and assumed in the PSA.

5.5 Other possible future generation projects

In addition to the committed projects identified, the GPA includes a long list of around 200 other potential generation projects. These cover a wide range of technologies—wind, geothermal, hydro, gas, coal, diesel, marine, and demand-side.

The list of projects has been prepared using information from the following sources.

- The Transmission to Enable Renewables project, for new hydro, wind, and geothermal generation—details available at http://www.electricitycommission.govt.nz/opdev/transmis/renewables
- Other commissioned reports on possible future generation projects
- Publicly available information such as newspaper articles and generator websites used to create the monthly generation update, which is available from http://www.electricitycommission.govt.nz/opdev/modelling/generation/index.html
- Industry publications such as annual reports
- Discussion with stakeholders

These projects are divided into two groups—the 'near future' projects that are not yet committed but are likely to be constructed in the next few years, and the 'prospective projects' that might be built from 2012 on.

50 Refers to changed use of existing generation - not to be confused with Manapouri MTAD.
51 Te Mihi is expected to replace Wairakei.

Near-future generation

Some generation projects have been designated as not yet committed but 'highly likely' to be constructed in the first few years of the generation scenarios. Each of these has been scheduled in the scenarios and assigned probabilities and commissioning years that reflect uncertainty about whether and when they will be built. The assignment of these 'highly likely' projects to scenarios is intended to be credible and consistent with the scenario 'stories', but, within these constraints, is somewhat arbitrary.

Table 9 presents the projects that the Commission views as highly likely in the next few years and the scenarios with which they are associated.

Table 9 Near-future generation projects in the generation scenarios

	Description	2010 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery
Arnold	Trustpower's proposed 46MW hydro project	2014				
Central Wind	Meridian Energy's proposed 120 MW wind project	2013		2014		2013
Hawea Control Gate	Contact Energy's 17MW retrofit hydro project		2013		2013	
Kaiwera Downs	Trustpower's 240MW wind farm	2015	2015			
Mahinerangi	Trustpower's 200MW wind farm		2014			
Manapouri	Meridian Energy's 90MW Hydro Tailrace amended discharge project	2011	2011	2011		
Mill Creek	Meridian Energy's proposed 70 MW wind project				2015	

	Description	2010 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery
Mohikinui	Meridian Energy's 85 MW hydro project			2015		
Ngatamariki	Mighty River Power geothermal project	2013	2013	2013		2013
Project Hayes Stage 1	150MW Stage 1 of Meridian Energy's proposed wind project		2013			
Project Hayes Stage 2	160MW Stage 2 of Meridian Energy's proposed wind project		2015			
Project Hayes Stage 3	160MW Stage 3 of Meridian Energy's proposed Wind Project in the South Island		2016			
Taranaki Co-generation	50MW co-generation proposal					2015
Te Mihi	Replacing Wairakei geothermal with equivalent capacity (a further upgrade may follow)	2013	2013	2013	2013	
Titiokura	Unison's 48MW proposed wind project		2013	2012		
Wairau	Trustpower's 73MW hydro project	2013	2014	2014		

Prospective projects

From 2012, the generation scenarios draw from a list of 'prospective' projects. These projects vary widely in terms of their current status.

- Some are consented or going through the consenting process, and are marked as either under appeal or applied for consent.
- Others have been proposed by generators, but are not yet in the consenting process.
- Some have been suggested, but are not currently known as being investigated by generators, because, for instance, they are not yet technically practical, or would not be economic under current market conditions.

Some of the projects are represented as generic plants, ie with no specific project name or developer indicated. In some instances this is for reasons of confidentiality. In other cases it is a useful means of incorporating possible new technologies into the scenario mix.

The list of projects includes:

- nearly 40 possible wind projects, ranging from 10 to 540MW, located throughout New Zealand (although with the majority in the North Island) and totalling over 4300MW;
- up to 150MW of new interruptible load, up to 1300MW of demand-side response available at peak, and up to 1000MW of vehicle-to-grid support from plug-in electric vehicles;
- 12 geothermal projects, located in the central North Island and totalling over 1000MW;
- over 55 possible hydro projects ranging in size from 10 to 340MW, located throughout New Zealand and totalling around 3750MW;
- six generic marine projects totalling nearly 250MW;
- nine assorted co-generation projects totalling about 450MW;
- eight gas-fired CCGTs totalling nearly 3000MW (Otahuhu C and Rodney stages 1 and 2), Taranaki CC 2 and Taranaki CC 3, plus three generic 400MW plants in Auckland, Taranaki and New Plymouth;
- 12 gas-fired thermal peakers, totalling about 1250MW, located in Taranaki or the Waikato;

- 24 diesel-fired thermal peakers, totalling about 1500MW, located as needed, and six 40MW diesel reciprocating engine generators;
- six generic solar plants each of up to 50MW each;
- seven black coal plants (generic projects in the 300 to 400MW range, nominally located at Glenbrook, Taranaki, Christchurch, Tauranga, Northland, and in the Waikato);
- two lignite plants (400MW generic projects located in Southland and Otago); and
- seven coal, gas, or lignite plants with carbon sequestration.

These projects vary widely in consentability and economic viability. For example, some of the modelled hydro schemes may face considerable difficulty obtaining consents. The selection of projects is intended to be indicative of possible opportunities.

In some scenarios, some projects are not offered to the model because they would not be constructed, owing to assumed consenting difficulties, etc. The treatment of these limitations is described in section 6.

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6. Key inputs and assumptions

6.1 Introduction

This section sets out the key assumptions made in relation to the development of the generation scenarios.

The assumptions described are confined to those considered to be primarily generation-related. They do not include the key assumptions regarding the following, as these are described elsewhere in this SOO.

- Electricity demand (section 3)
- Uptake of electric vehicles (section 3)
- Generation projects (section 5)
- PSA (section 8)

Two kinds of generation assumptions were made.

- Scenario-specific assumptions—those that differed between scenarios
- Common assumptions—those that were common to all the scenarios

Scenario-specific assumptions were the key drivers that differentiated one scenario from another. They had the following characteristics.

- Covered a range of outcomes in order to appropriately reflect uncertainty
- Influenced generation (and hence transmission) build
- Were consistent with the current policy context and expected technological change

Common assumptions were those that were:

- inherent in GEM; and
- considered to be reasonable for use across all scenarios.

The remainder of this section sets out the key drivers and some of the more important common assumptions. We cannot, however, describe every single assumption made in the scenario development. The most comprehensive source of information about the scenario development is GEM and its associated datafiles.[52]

Assumptions used in the development of the GPA are reviewed and amended as new information becomes available and following feedback from participants.

6.2 Key drivers of the generation scenarios

The key drivers across the five generation scenarios are summarised in Table 10. As noted above, the values of the key drivers were chosen to represent a credible range of possibilities, given the uncertainties faced by the sector. The results (build plans, emissions, renewable percentages, etc) are then determined from the input assumptions through the use of GEM. This approach contrasts with an 'output-driven' approach where the inputs are chosen to produce a predetermined set of results.

Table 10 Key drivers of the generation scenarios

Scenario	Eventual carbon price ($/t CO_2e)	Renewables preference	Availability of gas	Renewables available	Demand-side
2010 Sustainable path	60	Restriction on baseload coal- and gas-fired stations. Coal and gas CCS is allowed	High price path; Liquefied Natural Gas (LNG)	Extensive hydro, wind and geothermal available. Biomass, solar, and marine are available later	Extensive participation; electric vehicles uptake, with vehicle-to-grid connectivity
2010 SI wind	50	Restriction on baseload coal- and gas-fired stations. Coal and gas CCS is allowed	High price path; Liquefied Natural Gas	Extensive wind, especially in lower SI; some restrictions on geothermal development	Baseline participation

52 These can be downloaded at: http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html

Scenario	Eventual carbon price ($/t CO_2e)	Renewables preference	Availability of gas	Renewables available	Demand-side
2010 Medium renewables	30	Restriction on coal-fired plants until 2019, gas scarcity 2020–2030	Moderate price path	Extensive wind and geothermal, and some hydro available	Minimal participation; Tiwai smelter phases out of operation around 2025
2010 Coal	20	Restriction on coal-fired plants until 2017, gas scarcity 2020–2030	Moderate price path	Extensive wind and geothermal available; little new hydro can be consented; some existing hydro must reduce output from 2020	Baseline participation; electric vehicles uptake
2010 High gas discovery	40	Restriction continues on coal until 2019, though CCGTs can be built after 2015	Low price path	Moderate amounts of wind and hydro available; some restrictions on geothermal development	Baseline participation

6.2.1 Key driver #1—Cost of carbon

All five generation scenarios assume 'a price of carbon' ie a requirement to pay for greenhouse gas emissions.

The effect of the price of carbon in the model is to disincentivise baseload and mid-order thermal generation—especially coal-fired, but also gas-fired—and to encourage renewable development.

The framework of carbon charging may change over time. The Government's Emissions Trading Scheme (ETS) is a broad-based, economy-wide cap-and-trade scheme. [53] The ETS is neutral between domestic and international emission reductions. Future measures to curb greenhouse emissions may or may not use the same framework. New Zealand is targeting an emission level 10 to 20 per cent lower than the 1990 level by 2020.

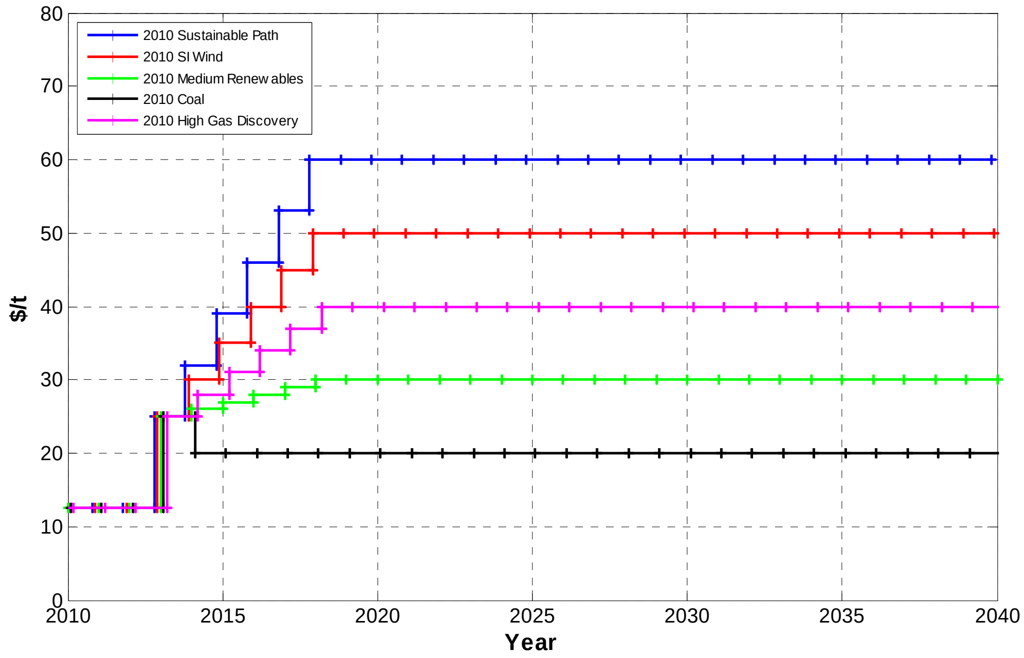
In the GPA, the cost of carbon is modelled as a flat rate applied to all electricity-sector emissions, denominated in real \$/t CO_2-equivalent (\$/t), with the assumption that the price of carbon applies from 2010, when the electricity sector comes under the ETS. The price starts low in all scenarios, as a result of free allocation of some units (\$12.5/t), and then becomes scenario-specific after 2013, reaching long-term level in 2018 and remaining constant thereafter. The resulting price paths are shown in Figure 19.

A range of carbon charge from \$20/t to \$60/t has been selected. A higher carbon charge has little effect on the merit order of the technology (see section 6.3.7) and therefore little effect on the outcome of the scenario. Also, a higher carbon charge (eg \$100 to \$200/t) would imply a higher penetration of wind into the system than the current 20 per cent allowed in GEM. Work on increasing this maximum wind penetration level is currently being undertaken.

In practice, carbon prices might fluctuate widely from year to year. No attempt has been made to model these effects.

53 A cap-and-trade scheme is a market-based approach to managing emissions. It sets a cap on the emissions and allows parties who need to cover existing emissions or increase their emissions to buy the right to emit from those who require fewer rights or who create rights, such as forest owners.

Figure 19 Modelled carbon prices for the five scenarios



6.2.2 Key Driver # 2—Availability and price of thermal fuels

Natural gas, coal, and oil are the three main fossil fuels currently used for electricity generation in New Zealand. The availability and price of natural gas and, to a lesser extent, oil, are important drivers of the scenarios.

Coal

The Ministry of Economic Development engaged Covec to examine current and expected future prices of coal in New Zealand for domestic and export markets. [54] Covec's work has been based on industry interviews and analysis of published price data. Covec estimated the lignite price to range from $2.50 to $3.0/Gigajoule (GJ) and the black coal price to range from $5 to $6/GJ.

PB New Zealand Limited (PB) was commissioned to study the key drivers of coal availability and prices for the GEM and the behaviours of these drivers into the future, along with the relationship between coal and oil price.[55]

54 http://www.med.govt.nz/upload/68784/coal-price-report.pdf

55 http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/pdfconsultation/GPA09/PB-coal-study.pdf

Since the oil shocks, fuel oil is rarely used for baseload generation, but may be kept as reserve generation or to provide peaking capacity. With fuel oil being less of a substitute for coal, changes in the oil price have a reduced effect on the demand for power generation fuels and prices.

PB estimated that:

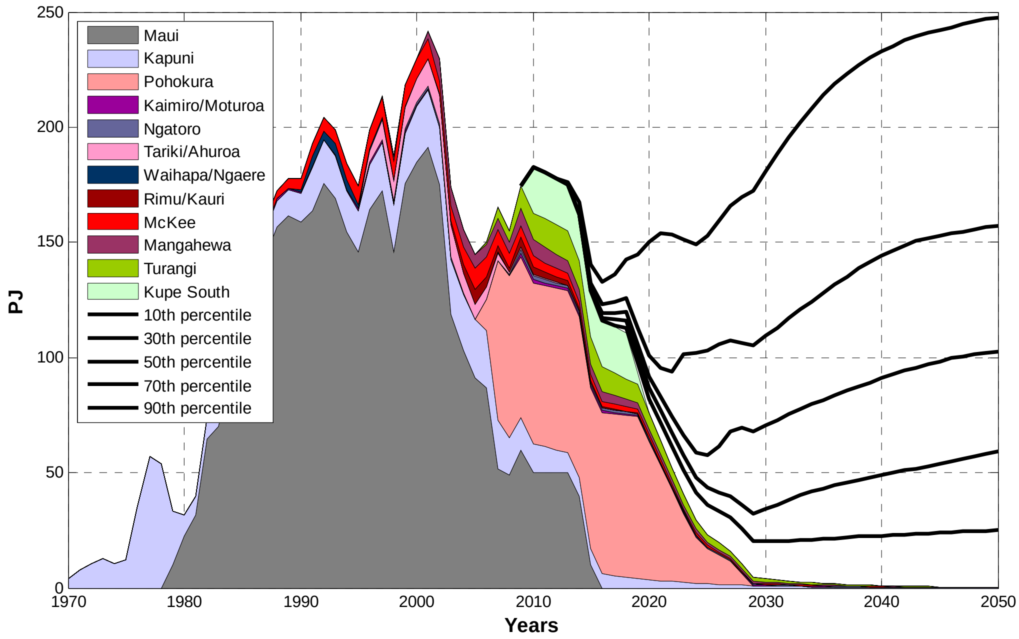
- coal prices would vary between $4 and $6/GJ with unlimited quantities between 2010 and 2050; and
- lignite prices would range from $2 to $3/GJ between 2010 and 2050.

Gas

The first step in deriving the gas availability forecast involved estimating the depletion of existing reserves using information published by the MED in the Energy Datafile which has details of the production rates and reserves of existing fields.

The second step was to perform a Monte Carlo simulation to forecast gas production from future discoveries. Monte Carlo simulation was selected as it is able to quantify the uncertainty in the forecast. Production lead time and profile shape for each field have been randomly chosen to provide sufficient diversity to the simulation, while the time of the discovery and the chances of finding small, medium, and large fields have been fixed. The simulation was run a large number of times to obtain reasonable statistics and the 10^{th}, 30^{th}, 50^{th}, 70^{th} and 90^{th} percentile production forecasts have been added to the production profile of existing fields to obtain the total net gas production. Production forecasts are shown in Figure 20.

Figure 20 Gas production forecast



The simulations suggest that gas production will drop between 2013 and 2018 because of the lead time needed to develop any new discoveries to production stage. Even in the highest gas production scenario, production is expected to decline to 150PJ.

As the price is clearly linked to fuel availability, five price forecasts have been derived. The historical industrial gas price seems to correlate with the net gas production, and has been used to obtain the gas price forecasts for the shorter term. This relationship has been adjusted to mitigate price extremes with floor and ceiling prices of $3/GJ and $13/GJ respectively.

Longer-term gas price forecasts have been calculated on the basis that if New Zealand enters a low or high gas production phase there will be, respectively, an incentive to buy or sell gas overseas. LNG is expected to be the cheapest way to import natural gas. A report describing the modelling of gas price forecasts can be found on the Commission website.[56]

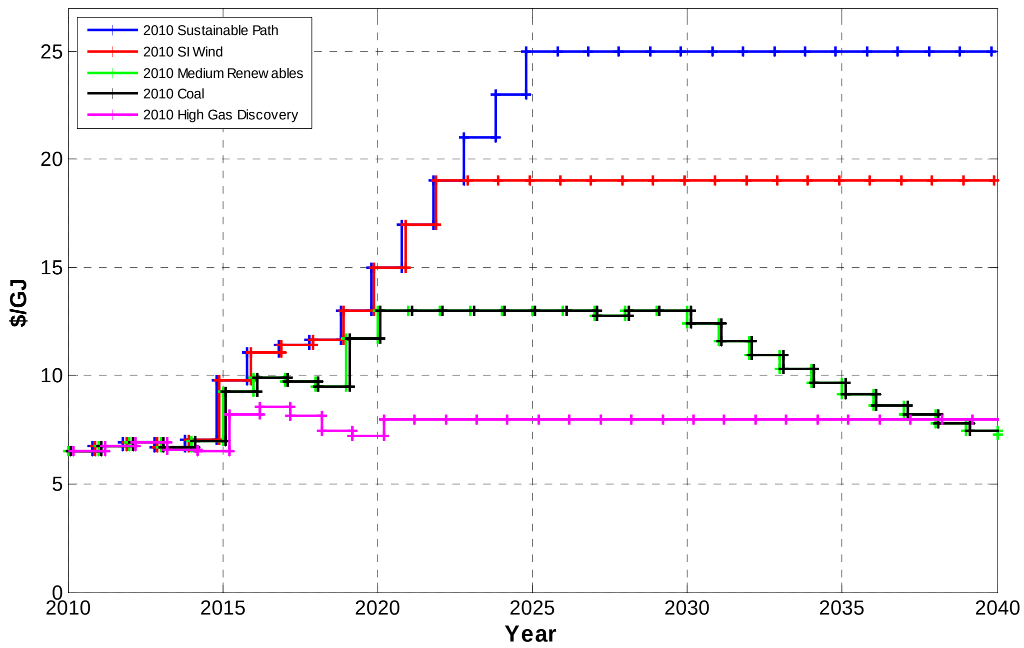
56 http://www.electricitycommission.govt.nz/opdev/modelling/information/gas-generation. This report sets out the relationship between international crude oil prices and LNG prices.

Each scenario follows one of three outcomes for the gas market.

- In the 2010 Sustainable path and 2010 SI wind scenarios, it is assumed that an LNG terminal is constructed as there is not enough indigenous gas (10^{th}, 30^{th} or 50^{th} percentile profile). LNG prices rise to $25/GJ and $19/GJ by 2025 and although unlimited amounts of gas can be obtained at that price, at this point, renewables tend to displace gas-fired generation.
- In the 2010 Medium renewables and 2010 Coal scenarios, it is assumed that new fields are discovered but the lead time between discovery and production means that gas becomes scarce between 2020 and 2030 (70^{th} percentile profile).
- In the 2010 High gas discovery scenario, it is assumed that new gas finds provide an ongoing supply of gas at relatively affordable prices (90^{th} percentile profile). Up to 170PJ per year is available at a price of $8/GJ.

Gas price and availability for each of the scenarios is presented in Figure 21 and Appendix 8 respectively.

Figure 21 Modelled gas prices for the five scenarios (exclusive of cost of carbon)



Oil

There is uncertainty about the future price and availability of oil for electricity generation. However, the sensitivity of the scenarios to those factors is relatively low, since the scenarios use oil only in small quantities for fuel-peaking generation. All scenarios assume that up to 25PJ per year of diesel can be used for electricity generation; this constraint is never approached. The future price of oil for electricity generation is assumed to be $25/GJ in all scenarios except the 2010 Sustainable path scenario, where it assumed to rise to $35/GJ by 2020.

6.2.3 Key Driver # 3—Access to renewables

The extent to which renewable resources will be able to be exploited to produce electricity in the next few decades is subject to several influences. It may be difficult to obtain resource consents (or resource consents on acceptable conditions) for some renewable developments, especially hydro. Long-term geothermal development is dependent on successful exploration. Integration of wind generation into the power system raises various technical challenges and uncertain system costs. Each of these difficulties can potentially be overcome, but it is not certain that all of them will be. Details of how uncertainty about the feasibility of renewable development has been built into the scenarios are included in the section below.

Geothermal

Generation from geothermal sources is highly economic and is expected to expand rapidly in the next decade. The economics of geothermal plants are such that if GEM were free to choose, it would build all the geothermal power stations available early and in quick succession.

However, such a rate of development seems unlikely as only two companies operate in the areas where geothermal power stations can be built. It has been observed that those companies develop their resources at a rate to match increases in their retail bases.

In order to cover the uncertainties that may restrict geothermal developments, such as resource management issues, three separate growth paths have been modelled.

- In the 2010 Sustainable path, 2010 Medium renewables, and 2010 Coal scenarios, geothermal capacity can be expanded by up to 750 MW, if economic.
- In the 2010 High gas discovery and SI wind scenarios, geothermal capacity can increase by a maximum of 500 MW if economic.

Another approach being considered is to apply rate restrictions in the early years, related to the expected expansion of the retail base for Mighty River Power and Contact Energy. Genesis Energy may be a new entrant to this area in the near term, and the promotion of a more fluid hedge market may enable the market to expand closer to the least-cost ideal.[57]

Although only conventional geothermal has been modelled in GEM, some additional resources such as hot dry rock and using relatively low temperature resources could be exploited in future. At the moment those technologies are not economic and are therefore not included in GEM. However, they could potentially be tapped in the future.

Wind

Wind development is also proceeding rapidly at present. Approximately 4000MW is available in the 2010 SI wind, 2010 Medium renewables, 2010 Coal, and 2010 High gas discovery scenarios (less in the 2010 Sustainable path scenario).

Wind energy 'penetration' refers to the percentage of energy produced by wind compared with the total available generation capacity. There is no generally accepted maximum level of wind penetration. The limit for a particular grid will depend on existing generating plants, pricing mechanisms, capacity for storage or demand management, and other factors. An interconnected electricity grid will already include reserve generating and transmission capacity to allow for

[57] Geothermal Energy: Summary of emerging technologies and barriers to development, Ministry of Economic Development, March 2010

equipment failures; this reserve capacity can also serve to regulate the varying power generation by wind plants. Studies have indicated that 20 per cent of the total electrical energy consumption may be incorporated with minimal difficulty. These studies have been for locations with geographically dispersed wind farms, some degree of dispatchable energy or hydropower with storage capacity, demand management, and interconnection to a large grid area for export of electricity when needed. Beyond this level, there are few technical limits, but the economic implications become more significant. Electrical utilities continue to study the effects of large-scale (20 per cent or more) penetration of wind generation on system stability and economics.

The Commission is currently working on replacing GEM's hard-coded constraint of 20 per cent with a formulation that would seek the least-cost wind generation/reserve capacity mix. The formulation would use regional-specific New Zealand synthetic wind speed data[58] to estimate the reserve required to maintain system security.

Hydro

In recent years, gaining consent for large-scale hydro generation has been difficult. It may or may not be possible to consent new schemes, especially those on rivers that are of high environmental or recreational value or where there are other significant uses for water. This is modelled by varying the availability of hydro schemes across the scenarios. The table below summarises the hydro availability.

Table 11 Availability of hydro in MW (excluding modifications to existing stations)

	Hydro peaking	Hydro run-of-river	Pumped hydro
2010 Sustainable path	1,070	1,310	900
2010 SI wind	920	1,150	300
2010 Medium renewables	730	440	900
2010 Coal	400	120	300
2010 High gas discovery	720	440	900

The 2010 Coal scenario models a future where it is difficult to obtain resource consent for hydro generation. It is also recognised that both constructing new hydro schemes and maintaining consents and water rights for existing hydro plants is problematic. Accordingly, the output and peaking capacity of existing hydro generation in the 2010 Coal scenario is reduced by five per

58 http://www.electricitycommission.govt.nz/opdev/modelling/synthetic-wind

cent in 2020, and by a further five per cent in 2030. In practice, there might be a significant reduction in output from a few schemes rather than a smaller across-the-board reduction.

Biomass

Reports prepared by consultants and government agencies enable biomass potential to be readily estimated. Information from those reports has been analysed to revise the assumptions that feed into GEM. The outcome of this analysis suggests that there could be potentially 230MW of energy from biomass by 2040.

The flow diagram presented in Appendix 9 shows how the installed capacity was derived. It is assumed that the earliest that biomass can be commissioned is 2010, because there are still a number of barriers and issues that would limit the use of wood resource. The availability of the total installed capacity is spread over 20 years and is represented by six potential co-generation power plants, as shown in Table 12.

Table 12 Biomass available in the five scenarios

Name	Capacity (MW)	Location	Earliest commissioning year
BioCog1	31	Kawerau	2020
BioCog2	63	Central	2024
BioCog3	63	Whirinaki	2028
BioCog4	31	Kinleith	2032
BioCog5	21	Ashley	2036
BioCog6	21	Nelson	2040

Solar

In 2009 the global solar photovoltaic power market added about 6.4GW of installed capacity, totaling over 20GW. The surge has been supported by government subsidies that include feed-in tariff schemes.

Without feed-in tariffs, solar technology is not economic in comparison with mature renewable generation. However, it is potentially a massive resource and research worldwide is being carried out to improve the efficiency of solar photovoltaic panels and other technologies such as solar thermal towers.

The solar assumptions used in GEM are based on the output of a review conducted by IT Power Work Limited and data available in the public domain. [59] In GEM, a total of 300MW is available, with 150MW in North Auckland and 150MW in the Nelson/Marlborough region. Each 150MW is split into three groups of 50MW becoming available in 2015, 2025, and 2035.

Solar generation cost is assumed to decrease over time with an assumed capital expenditure of $9000/kW, $5000/kW, and $3500/ kW. Using a capacity factor of 20 per cent, this leads to Long-Run Marginal Costs (LRMCs) of approximately $600/MWh, $450/MWh, and $250/MWh.

Marine

The pace of domestic marine energy activity has picked up over the last few years. Therefore, in early 2008 Power Projects Limited (PPL) was contracted to advise on potential marine energy (wave and tidal) schemes, including location, capacity, and energy production.[60]

Six wave farms with three different devices (Pelamis 750 kW, Pelamis 1.5MW, and Single Point Absorber 750 kW) were assessed. The yield capacity factor of the Pelamis 1.5MW and Single Point Absorber 750 kW seem high as they originated from modelled devices having high levels of power in a wide range of conditions.

The average capacity factors of the three devices at each location have been used to populate the GEM input file. This yields capacity factors between 0.55 and 0.65 which might be achieved in 15 years if full commercial development of the devices is realised.

The PPL report suggested that wave energy looks more promising in New Zealand than tidal energy, and for this reason four wave and two tidal schemes have been selected to populate the GEM input data file. The four wave sites with the highest capacity factor were selected. They are Port Waikato, Taranaki, Westport, and Southland.

Mapping performed on tidal current velocities suggests that the best locations to capture tidal energy in New Zealand are Cape Reinga, Cook Strait, and Foveaux Strait. Cape Reinga was not further studied because of the lack of transmission and distribution infrastructure. Detailed study on Foveaux Strait indicates that the turbine array provides only a small amount of energy in comparison with the energy that could potentially be harnessed from the Cook Strait currents. The likely cause of this difference is the smaller accessible area and lower current velocities.

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59 MED has recently contracted IT Power Australia to assess the future costs and performance of solar photovoltaic technologies in New Zealand. http://www.med.govt.nz/upload/67238/PV%20in%20New%20Zealand.pdf

60 http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/renewables/phase2/Marine-energy.pdf

The report also pointed out that large harbours and estuaries could offer a potential tidal resource. Crest Energy is currently looking at deploying a test turbine in the Kaipara harbour in Northland and therefore it seems reasonable to use the Kaipara harbour as the second potential tidal resource instead of Foveaux Strait (the first being Cook Strait).

As with wave energy, various devices have been modelled and the average capacity factor of the best sites (ie Cook Strait 2, 3, and 4) has been used to populate GEM. As no specific information about Kaipara harbour was available the Commission assumed a similar array size and capacity factor as for the Cook Strait sites.

The six selected schemes have been spread evenly from 2025 to 2035, with the highest capacity factor sites developed first.

The table below provides the details of the data that will be used as marine input data in GEM.

Table 13 Wave and tidal schemes available in the five scenarios

Name	Location	Substation	Capacity factor	Capacity (MW)	Energy (GWh/year)	Earliest built year
GWave4	Port Waikato	Glenbrook	0.55	37.5	180.7	2031
GWave3	Taranaki	Kaponga	0.57	37.5	187.2	2029
GWave2	Westport	Waimangaroa	0.59	37.5	196.8	2027
GWave1	Southland	Invercargill	0.65	45	213.5	2025
GTidal1	Kaipara harbour	Huapai	0.10	45	39.4	2033
GTidal2	Cook Strait	Haywards	0.10	45	39.4	2035

Nuclear

Nuclear power is economic[61] being similar to the renewables in having a high capital cost element and only a relatively small fuel cost component. However, major drawbacks with this technology remain, including handling of waste, decommissioning costs, and absence of a local supporting industry. It does have some advantages, being compact relative to power output and low carbon emissions.

Nuclear technology has not been included in GEM as nuclear generation is not permitted under current government policy.

[61] The Commission has worked with Brent Wilson on nuclear feasibility in New Zealand. The report can be found on http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/GPAs/2009/nuclear-feasibility-report.pdf. It was found that some type of reactors could be economic under a specific set of assumptions.

6.2.4 Key Driver # 4—Generation costs

A key aspect of the generation input data is the relative economics of the various types of generation.

LRMC is defined as the mean price at the relevant Grid Injection Point (GIP) that is sufficient to cover all plant costs (in this context, including capital financing costs, carbon costs, fuel costs, O&M costs, and transmission charges, but excluding network losses). A real pre-tax discount rate of eight per cent has been assumed in the calculation of LRMC. Assumed depreciation rates vary between technologies. LRMCs depend on load factor and have been calculated for several different load factors, where applicable.

Readers should be cautious when comparing the LRMCs shown here with those published in other documents. Differences in assumed project life, depreciation rate, treatment of tax, discount rate, load factor, and/or types of cost considered can make a substantial difference to calculated LRMCs—easily $20/MWh or more. If cost assumptions are to be compared, the comparison is best carried out on raw cost components (capital cost per kW, variable O&M cost per MW, etc).

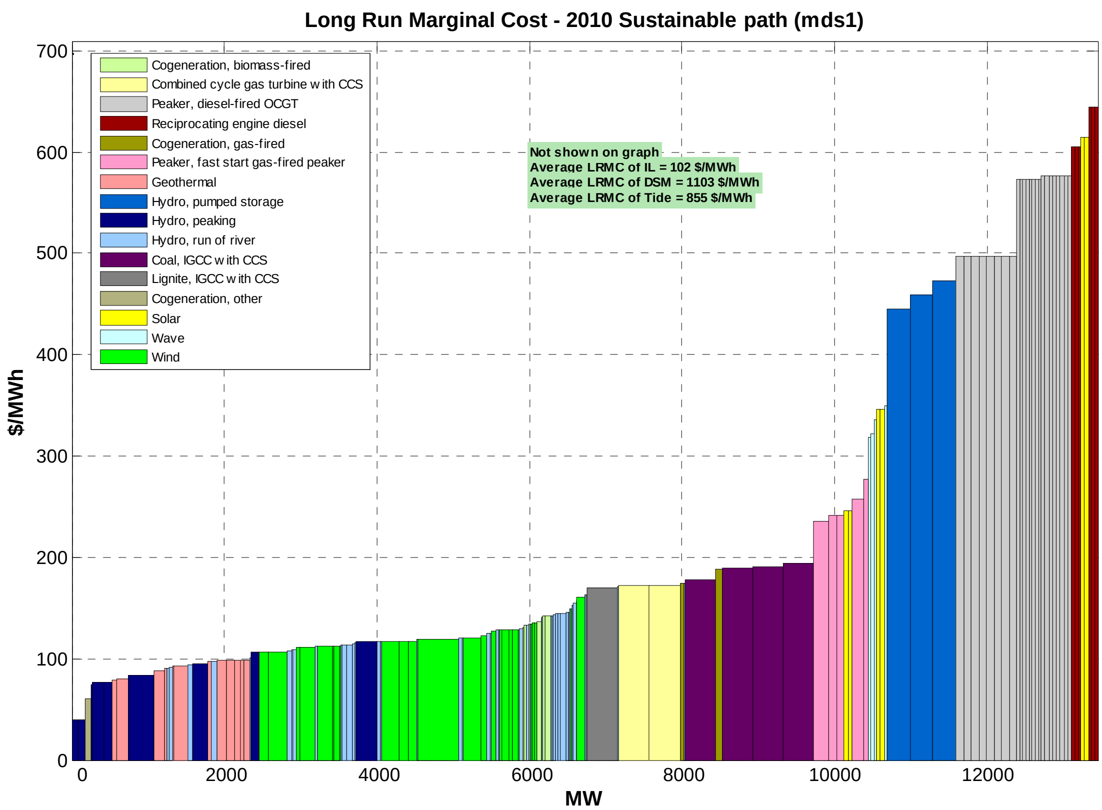
LRMCs assumed for each of the scenarios are presented below. The LRMC presented assumed some capacity factors by technology that are not used when solving the model. The LRMCs are presented to give a feel for generation costs, but are not directly used as inputs in GEM.

The following sections describe briefly the LRMCs of the five scenarios.

MDS1—2010 Sustainable path

In this scenario a high carbon charge ($60/t) and gas price (up to $25/GJ) make gas- and coal-fired stations uneconomic. For this reason gas and coal plants are not assumed to be built. This considerably assists GEM in solving as there are fewer options to choose from. In this scenario hydro and geothermal generation are the most economic options, having LRMCs below $100/MWh. Gas and diesel peakers are expensive but are expected to run only for short periods of time and at peak times.

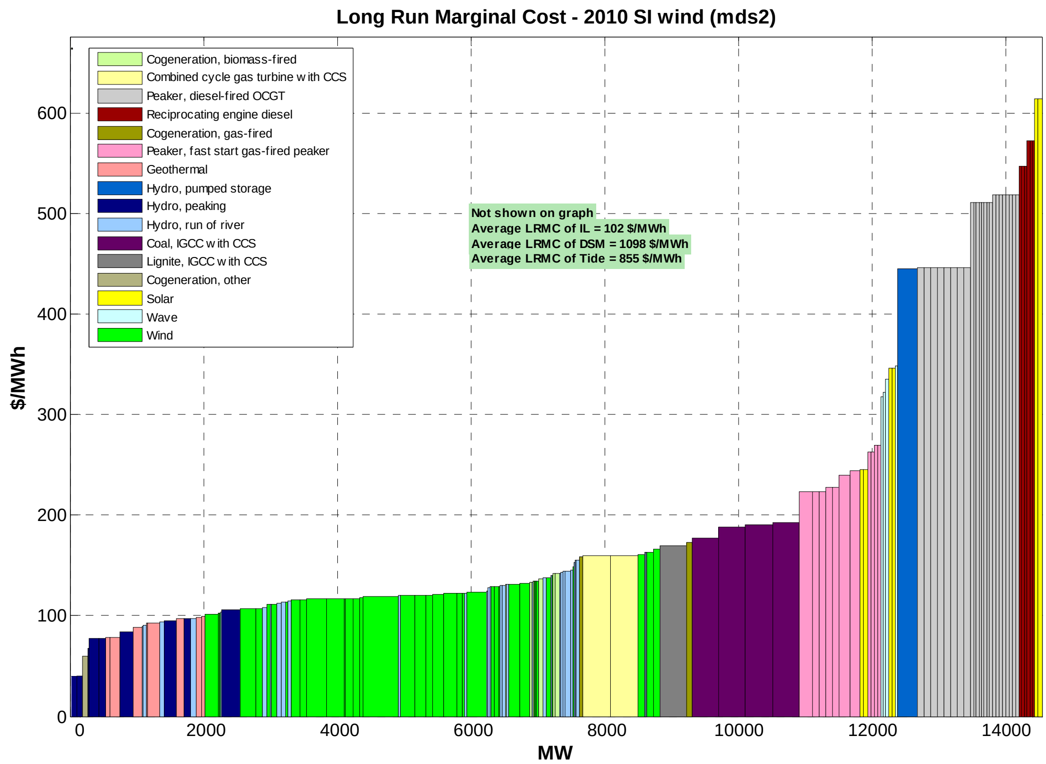
Figure 22 Long-run marginal cost—2010 Sustainable path (mds1)



MDS2—2010 SI wind

As with the 2010 Sustainable path scenario, the 2010 SI wind scenario has a high carbon charge ($50/t) and a high gas price (up to $19/GJ) making thermal plants uneconomic. The main differences between the two scenarios relate to the availability of wind and hydro.

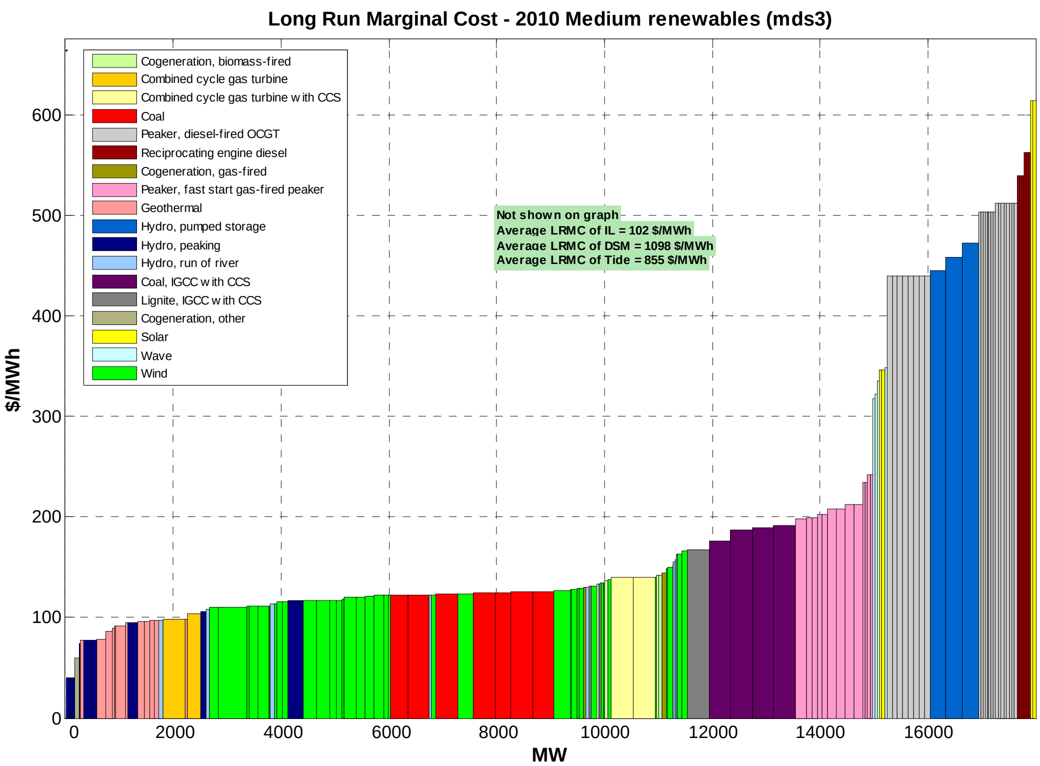
Figure 23 Long-run marginal cost—2010 SI wind (mds2)



MDS3—2010 Medium renewables

In this scenario gas- and coal-fired stations are available, and a relatively low carbon charge and fuel price make them economic. Under these assumptions, coal and wind have similar LRMC values. Geothermal is available between $77/MWh and $100/MWh, while hydro is not available below $150 /MWh because of the relative difficulty of obtaining consents compared with the 2010 Sustainable path and 2010 SI wind scenarios.

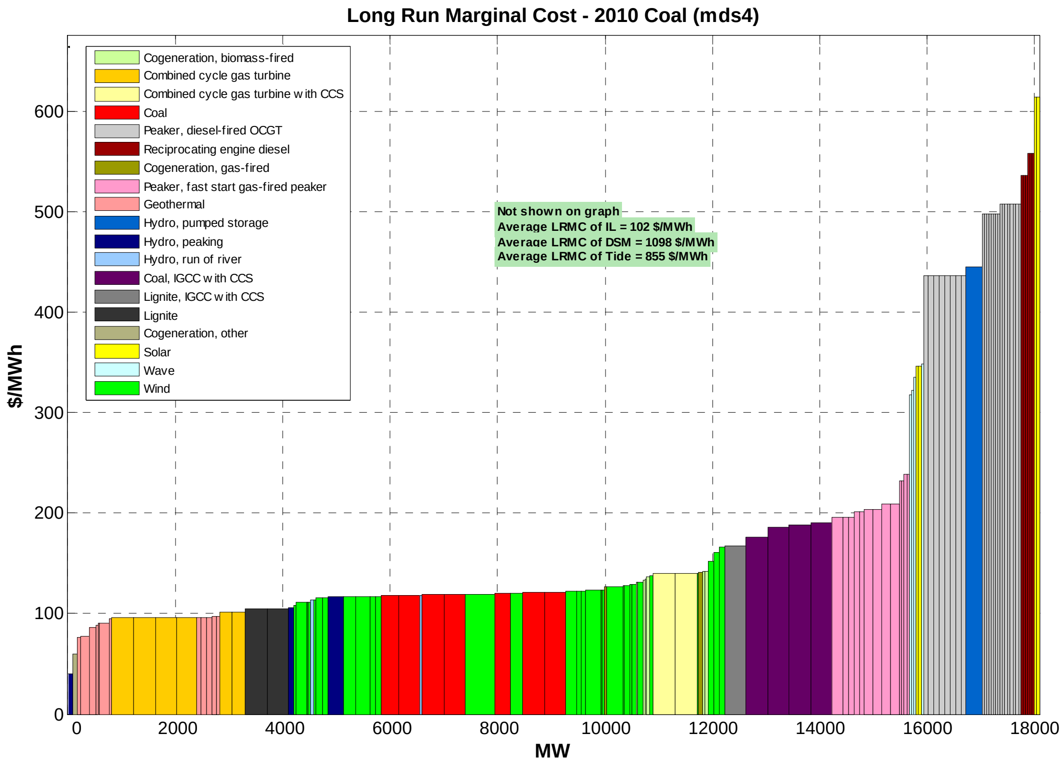
Figure 24 Long-run marginal cost—2010 Medium renewables (mds3)



MDS4—2010 Coal

The availability of hydro generation is limited in the 2010 Coal scenario, making geothermal and baseload gas-fired stations very economic ($70 to $100/MWh). With a low carbon charge ($20/t), the LRMC of lignite plants could be as low as the most expensive gas-fired station at $100/MWh. Again, coal and wind have similar LRMCs. However, comparing the 2010 Coal and 2010 Medium renewables scenarios shows coal descending slightly in the merit order because of the lower carbon charge.

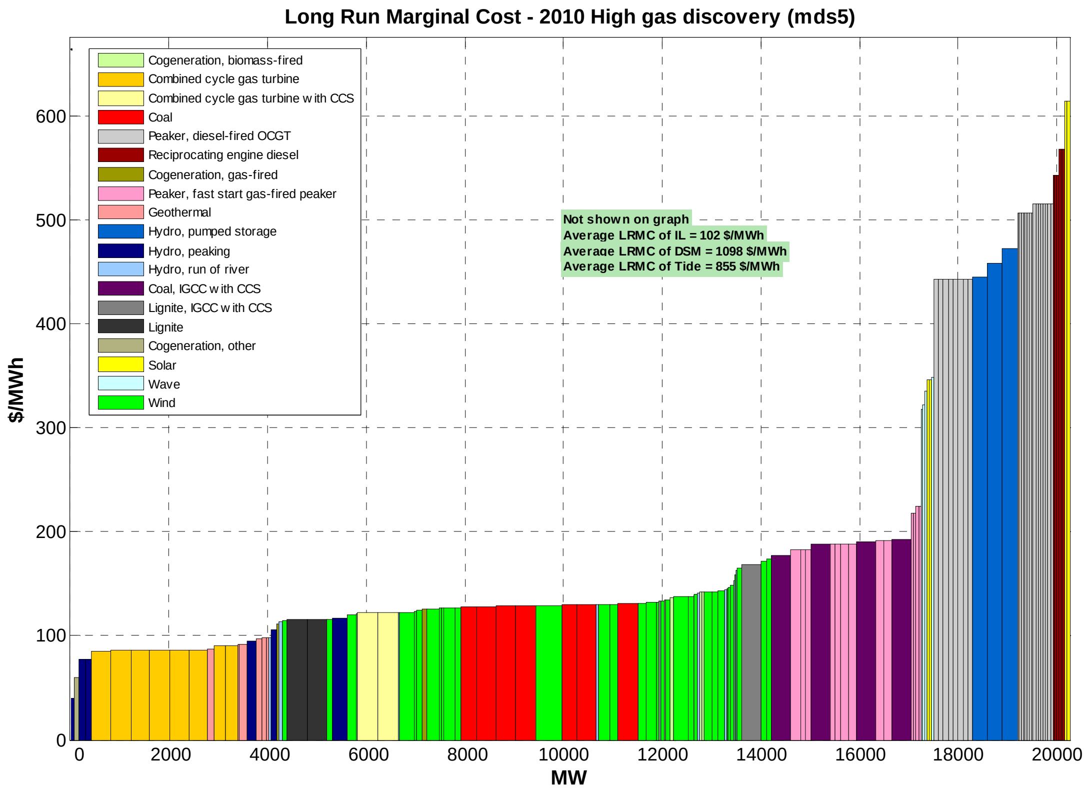
Figure 25 Long run-marginal cost—2010 Coal (mds4)



MDS5—2010 High gas discovery

In this scenario, a low carbon charge and gas price make baseload gas-fired stations the most economic option with an LRMC below $90/MWh. Geothermal is still a very attractive technology but in this scenario less geothermal generation is available.

Figure 26 Long-run marginal cost—2010 High gas discovery (mds5)



6.2.5 Key Driver # 5—Lifespan of existing thermal generators

Ageing plant will eventually be shifted to limited operation or decommissioned entirely. The fate of existing thermal generation is a key source of uncertainty in the power system generally, and in the five scenarios in particular. When ageing thermal generators are decommissioned, new generation is needed and transmission augmentations may be required.

The choice to retire a thermal generator is an economic decision driven by the value of electricity and the costs of keeping the plant in service. As a plant gets older, maintenance costs increase. Rising fuel and carbon costs would tend to make the economics of ageing thermal plant more difficult, as would the introduction of new, more efficient thermal plant.

In previous SOOs the retirement date of thermal power plants was set by reference to company announcements. However, the retirement date of thermal power plants is now assumed based on economic criteria. As refurbishment costs are highly dependent on exchange rate, GEM has also been updated to accommodate costs in foreign currencies.[62]

The Commission is not able to forecast generators' decisions, such as the potential decommissioning of Huntly, but considers it appropriate to model retirement decisions based on economic criteria.

6.2.6 Key Driver # 6—Demand-side assumptions

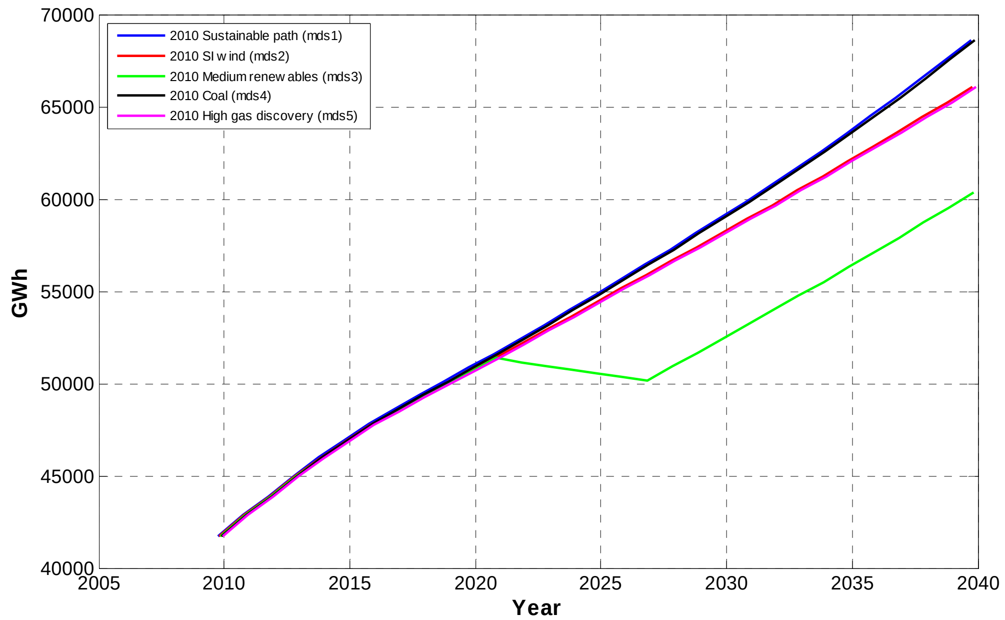
Much of the detail in the generation scenario modelling relates to the supply side. However, the demand-side is also important.

The scenarios presented are based on the medium growth forecasts described in section 3, but also include the following 'demand-side scenarios'.

- The 2010 Sustainable path and 2010 Coal scenarios assume uptake of consumer electric vehicles.
- The 2010 Medium renewables scenario assumes closure of the New Zealand Aluminium Smelters Limited (NZAS) at Tiwai in the 2020s (see section 6.2.7 for more details).
- The scenarios assume varying amounts of demand-side response at peak with the 2010 Sustainable path scenario having roughly 10 per cent of the peak demand available for demand-side response available.

62 Assumptions around the costs associated with thermal plant refurbishment are based on a report available at: http://www.electricitycommission.govt.nz/pdfs/opdev/modelling/pdfconsultation/GPA09/PB-thermal-station.pdf

Figure 27 Assumed demand in the five scenarios



The demand-side can contribute to managing peak demand through a variety of means.

- Providing interruptible load for instantaneous reserves
- Use of interruptible load to reduce peak demand (in response to transmission pricing signals or with the intention of reducing electricity prices)
- Increased price-responsive demand from major consumers exposed to spot prices
- Wholesale market improvements that facilitate the demand-side to predict and react to price signals effectively
- Price-responsive demand from residential and commercial consumers, if time-of-use pricing becomes widespread
- 'Anytime' demand reduction through energy efficiency or fuel substitution

These types of measures are included in the GEM modelling as 'demand-side response' and 'interruptible load', on the same basis as generation projects. However, it is not yet clear how effective demand-side response will be in helping to manage peak demand. The scenarios, therefore, have a range of assumptions about the amount of demand-side response that is available.

- The 2010 Sustainable path scenario allows up to 1450MW by 2040, following the growth of the peak demand.
- The other four scenarios allow 450MW by 2040.

The 2010 Sustainable path scenario also includes vehicle-to-grid technology, which could potentially make a very substantial contribution (1000MW) to managing peak demand from 2030 onwards.

6.2.7 Key Driver # 7—Status of New Zealand aluminium smelter at Tiwai

The Tiwai smelter represents the single biggest demand in New Zealand, peaking just over 600MW. The closure of the smelter would greatly change the supply/demand balance and have a major impact on transmission flows.

NZAS (owner of Tiwai) has not expressed any intention to close down, and has contracted to purchase electricity from Meridian Energy until 2030. However, it is still possible that the smelter could be closed before 2030, depending on the price of aluminium, the price of imported bauxite, and the electricity prices in New Zealand compared with those in other aluminium-producing countries.

Accordingly, it is appropriate to include one scenario where the plant closes before 2030.

The smelter closure takes place in the 2010 Medium renewables scenario. In theory it could occur in any scenario, since it would depend largely on the exogenous factors listed above. However, to include early closure in more than one scenario would give too much significance to this uncertainty.

It is assumed that the smelter is phased out over the period from 2022 to 2027, given the uncertainty.

It is also reasonable to expect that any closure of Tiwai would be the result of significant negotiation between NZAS and Meridian Energy, or perhaps other parties. Presumably then, the closure of Tiwai would likely coincide with some other increase in demand and/or an extended period of little generation capacity expansion.

6.3 Assumptions common to all generation scenarios

A number of assumptions applied to the GEM model are common to all scenarios tested. The most important of these, in terms of materiality to the model's output, are described below. All assumptions used in the model are in the specified associated input datafiles.

6.3.1 Energy constraints

The energy constraints in GEM state that total electricity generation must be sufficient to meet demand. In years with high hydrological inflows ('wet years'), there should be enough generation except, perhaps, at peak times. In dry years it may be necessary to use expensive forms of generation such as thermal peakers to meet demand. If the amount of available generation is still insufficient, electricity consumption must be curtailed, at an assumed shortage cost of $500/MWh.

The generation scenarios are optimised over a range of inflow sequences from very dry (inflows equivalent to those experienced in 1992), through dry (2003), medium (2002), wet (2000), and very wet (1998). The build schedule in each scenario is chosen to have the lowest weighted average system cost over this set of inflow sequences, with the extreme cases having less weight (eight per cent each) than the three intermediate cases (28 per cent each). This approach is intended to mimic the real situation experienced by generators, ie there is an incentive to build generation so that it is available for dry years, but plant owners must consider that such plant may not be needed in wet years.

In dry years, the following effects would typically be seen in the GEM generation dispatch for the winter periods.

- Coal- and gas-fired generation increase output.
- If dual-fired units at Huntly are operating in dry-year reserve mode, they produce output if inflows are low enough.
- Diesel-fired peakers are commissioned and generate if inflows are very low.
- Demand reduction may occur.

In wet years we see the following effects.

- Coal and gas generation operate at the minimum level allowed in the model.
- Peakers operate only at times of peak demand and/or low wind output.
- Renewable energy is spilled, eg wind.

6.3.2 Capacity constraints

The 'capacity' constraints in GEM state that electricity generation capacity must be able to meet cold-year winter peak demand in each island, with enough reserve to cover certain contingent events. The contingencies considered are the loss of the single largest generating unit or a single HVDC pole. The constraints take account of higher transmission losses at peak times and of the need for some generation to be assigned to frequency keeping.

These are 'hard' constraints—they must be satisfied in all years. They have a significant effect on the build schedule, tending to lead to:

- the development of demand-side options;
- the construction of thermal-peaking plant;
- the construction of renewable peaking plant, such as pumped hydro, in the distant future years; and
- a preference for mid-order generation over baseload.

The GEM peak-demand forecasts used in the capacity constraints are derived from the GPA's prudent and expected regional peak forecasts. The GEM forecast starts at the level of the GPA prudent peak forecast for 2008, and then increases at the growth rate of the GPA's expected peak forecast. This approach is intended to predict cold-year demands under a scenario of average underlying demand growth, as opposed to using the prudent forecast throughout, which would model a scenario of high underlying demand growth.

In the capacity constraints, each form of generation is assigned a 'peak contribution factor' that quantifies its ability to contribute to meeting peak. A factor of 1 would indicate that the plant was guaranteed to be fully available at peak time; a factor of 0.1 or below would indicate that its availability at peak was extremely limited. Some of the peak contribution factors used are shown in Table 14.

Table 14 Peak contribution factors in GEM

Technology	Peak contribution factor
Thermal (various)	0.95
Co-generation	0.60
Geothermal	0.90
New hydro backed by storage	0.95
New run-of-river hydro	0.65
Wind	0.20
Marine	0.30

Existing hydro is omitted from the table because its contribution to peak is handled differently in the model.

The factors assumed for thermal, co-generation, geothermal, and existing hydro generation reflect typical levels of availability of existing plant during peak periods. The factors of 0.65 for run-of-river hydro and 0.2 for wind are based on exploratory analysis carried out by the Commission.[63]

The impacts of increased wind penetration on the New Zealand power system are not yet firmly established. Consequently the appropriate peak contribution factor for wind also remains to be established. Some parties have suggested that the correct peak contribution of wind power may be as high as 40 per cent for small amounts of additional wind; others suggest that the correct figure is closer to zero. Analysis performed by the Commission and others suggest that this should be at least 30 per cent for moderate levels of wind penetration. However, this depends on the mix of other generation sources assumed. The 20 per cent figure has been adopted as a conservative approach at this stage.

63 Using statistical techniques to convolve the output of simulated hydro and/or wind generators with the availability curve of the rest of the generation stack.

6.3.3 Flexibility of fuel supply

The generation sector must be flexible in its output to meet variations in demand on various time scales. In the past, much of this flexibility has been provided by hydro generation, but it appears that in the future, thermal generation may play a larger role. In short time-scales, thermal generators can ramp up over a period of minutes to hours to meet peak demand. On longer time-scales, thermal generators can produce more power in dry and/or calm years, to make up for the lower contribution of renewables. This is referred to as 'dry-year swing'.

In the short term, the difference in hydro production between a 1-in-20-year wet year and a 1-in-20-year dry year is of the order of 6000GWh, or about 15 per cent of total electricity supply. This gap must be made up somehow. Currently, the main source of dry-year swing is increased generation at Huntly Power Station; the other options are increased production from gas generators, oil-fired generation, reduced spill from renewable generators, and/or demand reduction.

In some scenarios, the coal-fired units at Huntly Power Station are shifted to a limited operation mode or closed entirely. With Huntly less able to provide dry-year swing, a different source must be found. The options in the model are:

- using oil-fired peaking thermal generators;
- demand reduction;
- building surplus renewable baseload and spilling energy in wet years; and
- using gas for dry-year swing.

Since natural gas is cheaper than oil, it would seem economic to use gas-fired rather than oil-fired generators to provide dry-year swing and to help in meeting peak demand. However, the ability of gas generators to produce flexible output is dependent on their ability to obtain a flexible supply of fuel.

Generally gas is sold to generators on a 'take or pay' basis, which limits flexibility. This, in turn, is driven by the lack of physical flexibility in the gas production sector. Increased flexibility in gas supply is possible in theory, but would come at a significant cost.

Measures by which it could be achieved include:

- continued overbuild in gas production facilities (unlikely);
- gas storage, ie in depleted gas reservoirs such as Contact's facility currently being developed at Ahuroa;

- LNG deliveries, if an LNG terminal were in place; and
- gas demand response (eg Methanex).

The cost of flexible gas supply is modelled in the scenarios by:

- requiring CCGTs to operate as baseload, with load factors varying between 60 per cent and 100 per cent less outage. This means that CCGTs are limited in their ability to provide dry-year swing, and cannot operate as peaking plant; and
- allowing new Open Cycle Gas Turbine (OCGT)[64] 'gas-fired peakers' to be built. These fast-start plants can operate at a wide range of load factors, and can provide dry-year reserve and peaking capacity. However, their gas supply is subject to a 'flexibility charge' of as much as $2/GJ.

6.3.4 HVDC assumptions

Transmission capacity assumptions for the HVDC are 970MW to 2011, 1000MW from 2012 to 2013, and 1200MW from 2014 onwards. GEM is free to build up to 1400MW from 2016.

The five scenarios assume the maintenance of the current HVDC charge. The yearly charge has been derived as follows.

- The estimated HVDC costs from Transpower have been allocated on a yearly basis, taking into consideration capital value, operating cost, tax charge, and depreciation. An asset build charge estimate was obtained from 2010 to 2040.
- As the HVDC charge depends on the balance of the North Island and South Island build schedule, the five scenarios were run and the total South Island capacity was used in order to derive the five-yearly charge expressed in $/kW.
- The five HVDC yearly charges were averaged and this profile was used for the five scenarios.

The HVDC charge assumptions used as inputs in GEM for the five scenarios can be found in Appendix 10.

[64] An open cycle gas turbine is a combustion turbine plant fired by fuel to turn a generator rotor that produces electricity. The residual heat is exhausted to the atmosphere.

6.3.5 Treatment of intermittent generation

In some scenarios, the proportion of wind generation rises significantly over time. Integrating increased amounts of wind into the power system will lead to various challenges. The Commission carried out the Wind Generation Investigation Project (WGIP) to study some of these potential problems and mitigation options. [65]

Wind generation integration issues are modelled in the scenarios in several ways.

- Wind is assigned a peak capacity factor of just 20 per cent in the capacity constraints.
- Two of the five capacity constraints are 'calm day' constraints that require the power system to be able to meet winter peak demand with no output from any wind generators, but with reserves dispatched.
- There is an overall restriction of 20 per cent on the proportion of New Zealand's total annual electricity supply that can be produced by wind (reflecting general uncertainty about the problems that may arise at very high levels of wind penetration in an 'islanded' system).
- Peaking generation is required to balance wind output.

Clearly, the output of wind generators will vary over time. At some times, the aggregate output from all New Zealand's wind farms will be substantially less than their average output. The difference will need to be made up by other forms of generation, including hydro and thermals. The ability of thermal generation to increase output to balance wind will be limited, depending on the amount of advance warning. Thermal peakers are able to start relatively quickly from cold, but the ability of mid-order thermal plant to ramp up in time may be limited. The implication is that with increased amounts of wind generation, variability may require relatively expensive peaking generation to be dispatched, which could increase system costs. Further, if wind output is low when demand is near annual peak, then some form of peaking generation will certainly be required.

GEM attempts to model these dynamics by splitting some blocks of the LDC into 'low-wind' and 'high-wind' sub-blocks. As Figure 28 and Figure 29 show, there are six main blocks in the LDC, of which the smallest is a 'peak block' of just nine hours per quarter; the top three load blocks are subdivided. Based on exploratory analysis, wind output is assumed to be half the mean level during the 'low-wind' sub-blocks, which account for one quarter of the total hours per quarter, and is increased during the 'high-wind' sub-blocks to compensate.

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65 http://www.electricitycommission.govt.nz/opdev/comqual/windgen/wgip

Figure 28 Load duration curve, quarter (low-wind (red), high-wind (green) and medium-wind (blue) sub-blocks, showing demand by load block and remove "demand")

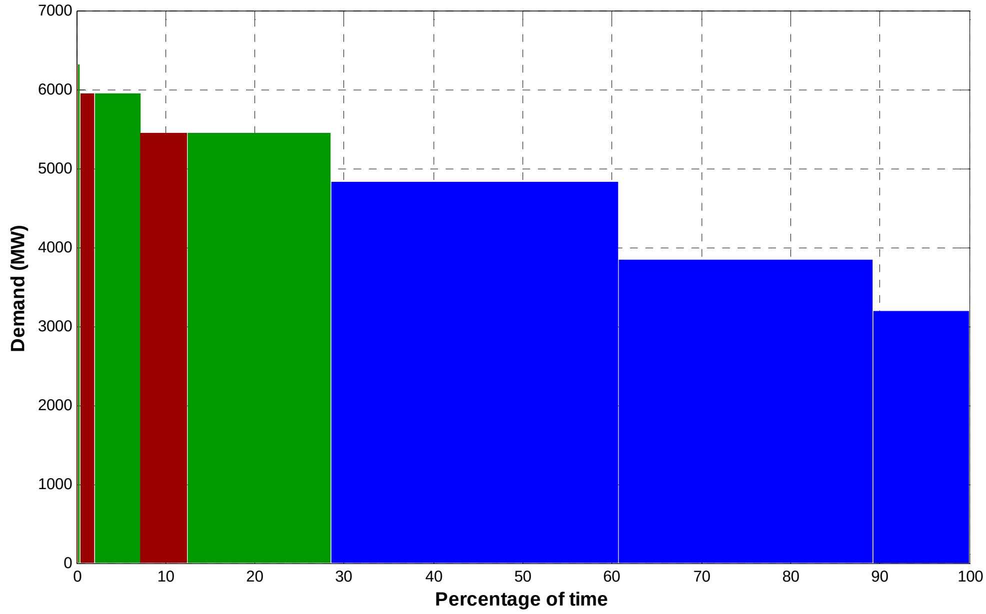


Figure 29 Load duration curve with wind output removed (low-wind (red), high-wind (green) and medium wind (blue) sub-blocks, showing the residual demand after wind output is subtracted and MW only on Y axis)

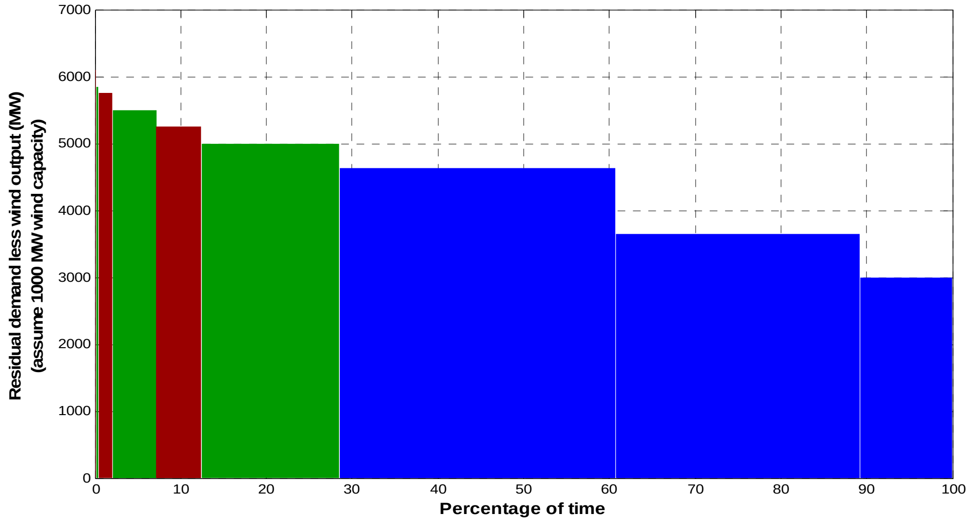


Figure 29 assumes a wind capacity of 1000MW.

Generally, some expensive peaking generation will run during these peak and low-wind blocks. If there is still insufficient generation to meet demand, then demand-side response at peak must activate, at a cost of $1000/MWh or higher. The cheaper dry-year demand response cannot be used, nor can coal in dry-year reserve mode. Further, in the low-wind blocks where demand is relatively low, even baseload and mid-order thermals have a limited ability to contribute (since they might not be running before the wind drops and be able to ramp up in time).

The effect of these model features is to better model the need for peaking generation to be built and dispatched in scenarios with high levels of wind penetration. As work on developing a model is still in progress, it has not been used for the purpose of developing the scenarios.

6.3.6 Siting of generation

In GEM, each potential generation project is assigned to a specific location.

- For renewable generation, these locations are based on the distribution of renewable resources.
- For baseload and mid-order thermal generators, several possible locations are provided for plant of each type. These locations are consistent with the availability of fuel for gas and lignite generation, but are otherwise somewhat arbitrary.
- Diesel-fired peaking generators are assumed to be located at major demand centres for modelling purposes, but in fact could be almost anywhere. Different sites for these generators could be explored as part of a GIT application.

The version of GEM used to produce the generation scenarios is a 'two-node model'—it is spatially aggregated to the island level. Project locations (within each island) are important for PSA, but are not so important to GEM results in the case of a two-node variant of the model. HVDC inter-island transfers are modelled, but transmission constraints on the AC parts of the grid are not considered, although losses on the AC part of the grid are accounted for by adjusting load in each island. Transmission charges other than the HVDC charge are not modelled.

However, project locations do affect the model in one respect. The variable O&M costs at each plant are adjusted by regionally specific location factors in order to reflect the observed differences in nodal prices attributable to transmission losses. A total of 12 location factors are specified, ranging in value from 1.00 to 1.13. The location factors generally increase in value the further north a region is located. For example, Southland has the lowest value of 1.00 and

Northland has a value of 1.10. The West Coast and northern parts of the South Island have the highest value of 1.13.

An implied assumption underlying the use of the two-node model is that enhancement of the AC grid takes place over time as required.

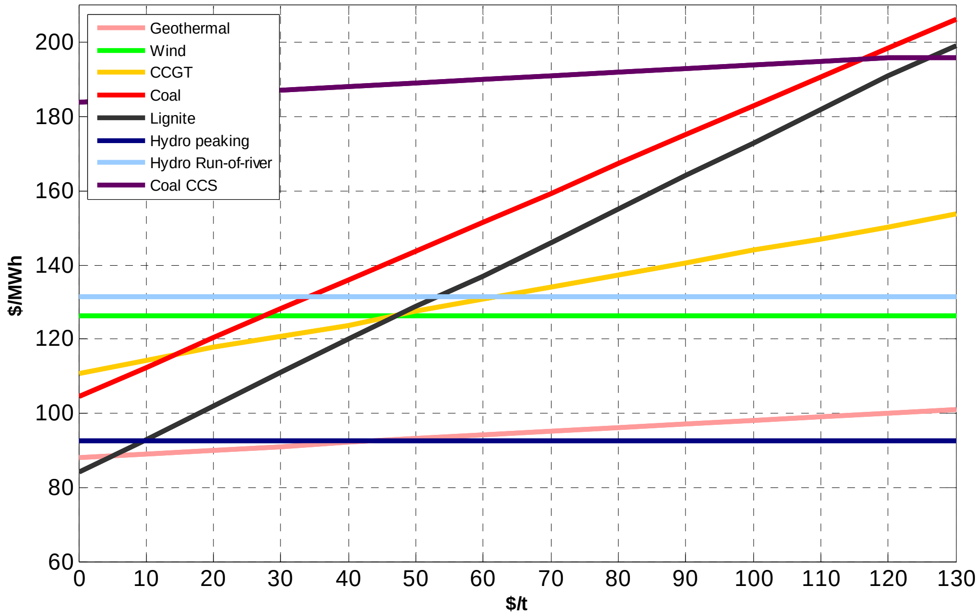
6.3.7 Costs

Solar and marine generation are the most expensive renewable technologies because of the low capacity factor and expensive technology. These two technologies could see some major improvement in the near future, which would lower their costs significantly. Looking at CCS technology it seems that a high carbon charge would be required in order to make this technology economic. Only small-scale projects are being developed at this stage worldwide and the absence of accurate costs makes this technology very uncertain.

An analysis has been carried out to determine the carbon charge required for CCS technology to become economic against conventional thermal plant. Analysis suggests the carbon charge has to be at least at $120/t. Figure 30 shows the average LRMC for a range of technology over a range of carbon charges.

Figure 30 also shows that under these assumptions a carbon charge higher than $60 to $70/t will not change the merit order of the technologies and therefore the outcome of the scenarios. It can be seen, for example, that CCGT technology is expected to be economic against wind technology up to $50/t. The steeper the gradient the more the technology is affected by the carbon charge, ie the renewable energies such as wind and hydro generation have a flat line while geothermal has a very small gradient.

Figure 30 Average LRMC as a function of the carbon charge



Assumptions: gas price = $13/GJ, coal price = $4.5/GJ, and lignite price = $1.8/GJ

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7. The generation scenarios

This section describes the five generation scenarios developed from the application of assumptions described in earlier sections.

Each scenario is defined by a schedule of new generation projects on a timeline from 2010 to 2040. The schedule has been developed using the GEM model, with the demand forecast to be met, and key inputs and assumptions as described in the preceding sections. The new generation projects for the scenario are listed, and information is also provided about the consequences in terms of generating technology mix, security of supply, capital and operating costs, fuel use, and greenhouse gas emissions.

Although the results and commentary extend to 2040, readers should view the predictions with a degree of caution proportionate to how remote the forecast is. Even predictions to 2015 are affected by many uncertainties that relate to policy, fuel prices, resource availability, and technological costs. Projections beyond 2030 are attempting to describe a world in which our economy, society, environment, and technological options might be very different.

7.1 Introduction and overview

The scenarios are expressed as build schedules, ie as lists of projects assumed to be constructed, by commissioning year including generator decommissioning.[66]

It is emphasised that the generation projects included in each scenario are to be regarded as a representative mix, consistent with the 'story' of that scenario. The inclusion of one project rather than another should not be considered as indicative of a Commission view that the first project is more technically feasible, more likely to obtain a resource consent, or more economic. Projects are simply included as instances of the types of plant that might be constructed and the locations in which they might be located.

Table 15 describes the scenarios, showing some of the major events projected to occur in each five-year period until 2040.

Figure 31 shows the energy share in GWh by fuel in 2010. This figure is valid for the five scenarios and will be used in the next sections to compare the energy share between 2010 and 2040.

[66] These schedules are reproduced in full in Appendix 2 for each of the scenarios.

Figure 31 Energy share by fuel in 2010

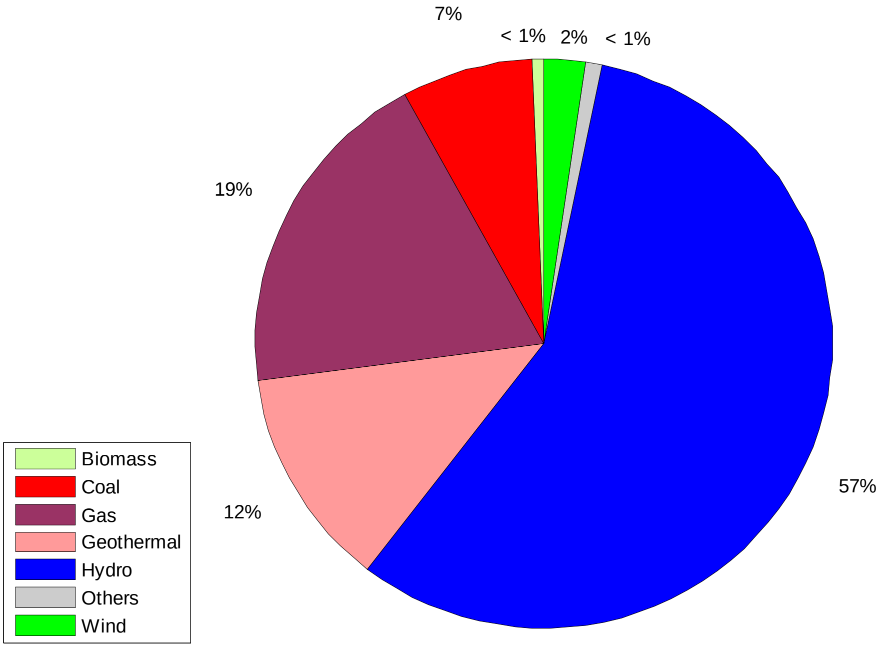


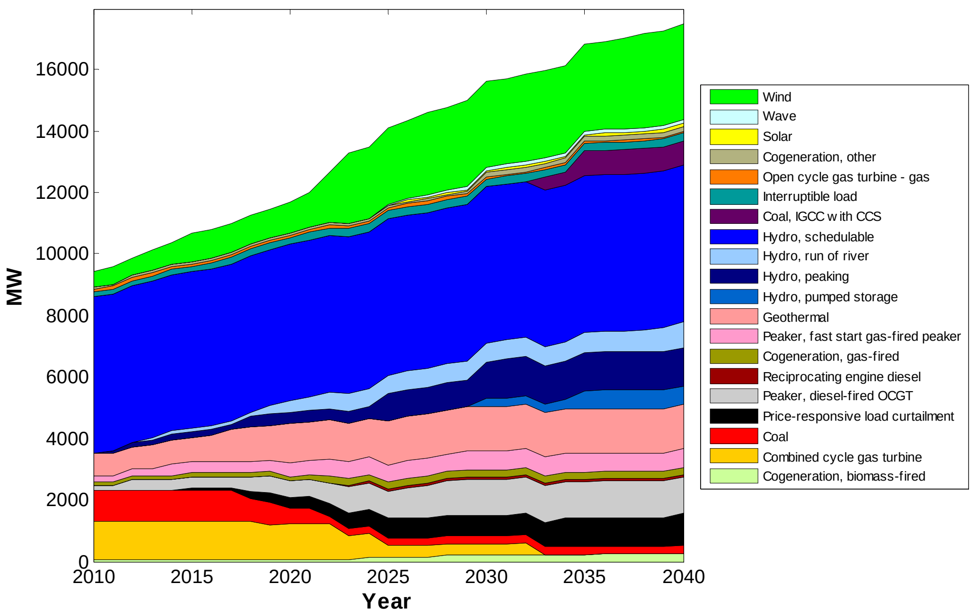
Table 15 Timelines to 2040 for the scenarios (based on summarised GEM output)

Scenario	2010–2012	2013–2018	2019–2024	2025–2030	2031–2040
2010 Sustainable path	New wind and geothermal developments, with thermal peakers to provide security of supply. New HVDC Pole 1.	One coal-fired unit at Huntly closes down. Hydro and geothermal development backed by thermal peakers.	Two coal-fired units at Huntly and Taranaki Combined Cycle (TCC) close down. Hydro and geothermal development, backed by demand-side response.	E3p is decommissioned. Hydro, NI wind, marine, and biomass development backed by thermal peakers and demand-side response.	Consumer electric vehicles becoming widespread with vehicle-to-grid technology in place. Renewable development continues. CCS, solar, pumped hydro, and marine energy developed.
2010 SI wind		Important SI wind developments, backed by thermal peakers.	Two coal-fired units at Huntly and Otahuhu B close down. Hydro, wind, and geothermal developments	Wind development backed by more thermal peakers and demand-side response.	More hydro and wind development. One CCS coal-fired unit at Huntly is commissioned
2010 Medium renewables		Geothermal development.	One coal-fired unit at Huntly and TCC closes down; replaced by a more efficient coal-fired station and geothermal developments.	One coal-fired unit at Huntly closes down. Tiwai smelter begins to closes down. Little generation development.	Mixed renewables and CCGT built.
2010 Coal		Geothermal development.	One coal-fired unit at Huntly and TCC close down; replaced by two, more efficient, coal-fired stations.	Lignite plant built in the South Island.	One coal-fired station and three new gas-fired stations are commissioned.
2010 High gas discovery		One coal-fired unit at Huntly closes; replaced by two CCGTs.	One coal-fired unit at Huntly closes and some geothermal developments.	One coal-fired unit at Huntly closes. Two other CCGTs built in the North Island.	Gas-fired stations continue to provide a high proportion of supply.

7.2 2010 Sustainable path scenario

Figure 32 illustrates the installed capacity by year and technology and Figure 33 shows the energy share by fuel in 2040 for the 2010 Sustainable path scenario. The installed capacity by fuel is shown in Appendix 11 Figure 51. The energy by technology and by year is shown in Appendix 13 Figure 61 and the energy by fuel is shown in Appendix 12 Figure 56.

Figure 32 Installed capacity by technology by year—2010 Sustainable path scenario

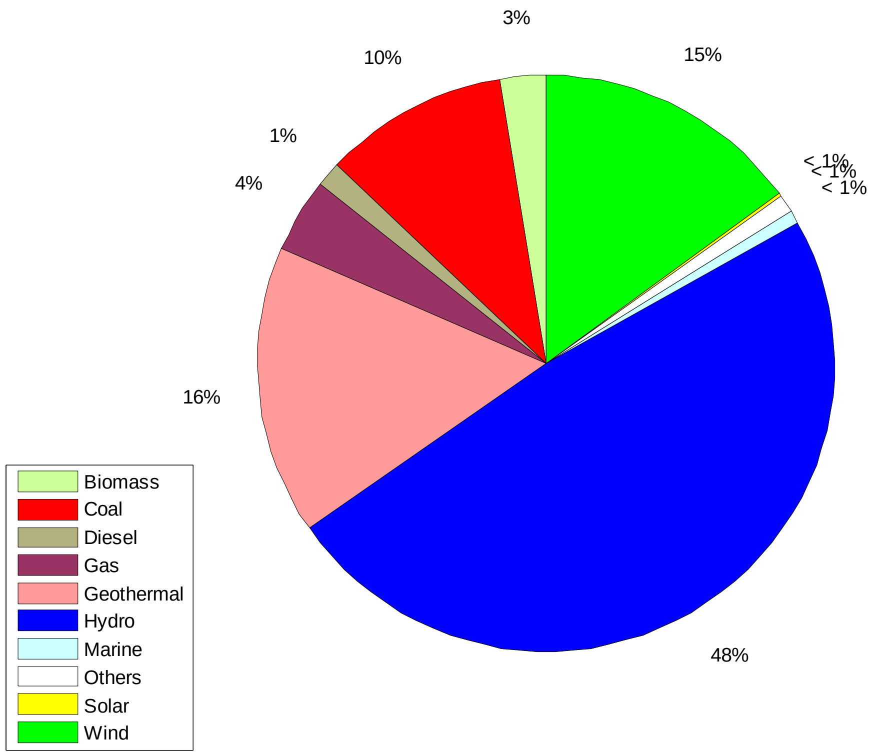


The major features of the 2010 Sustainable path scenario are as follows.

- Combination of high carbon charges and high gas prices leads to renewable projects being very cost-effective relative to thermal generation, and displacing generation from existing thermal plants (with three Huntly units, TCC and e3p).
- Major development of renewable generation takes place in both North and South Islands. Wind generation is developed extensively with about 2500MW of installed capacity by 2025 (see Appendix 16 Figure 76), geothermal capacity reaches 1400MW as early as 2025, and 1500MW of new hydro is constructed by 2025, including run-of-river, storage-backed, and pumped modes.
- Biomass (Figure 77), solar (Figure 88), and marine (Figure 89) generation enter after 2020.

- Coal plant with carbon capture and storage follow after 2030, to help meet increased consumption.
- Thermal peaking plants are required in order to balance intermittent generation, provide dry-year swing, and supply reliable capacity to meet peak demand. These are built periodically over the years—by 2030 the scenario includes 1250MW of diesel-fired peakers of various types (see Figure 82 and Figure 84) and 600MW of flexible gas-fired generation (Figure 83).
- Interruptible load (IL) and price-responsive demand, driven by advanced metering, time-of-use tariffs, and other initiatives, have an important role to play in balancing intermittent generation and meeting peak demand (Figure 81).
- Increases in gas prices from 2015 lead to declining CCGT use (see Figure 33 below) until the decommissioning of TCC in 2023. Existing coal-fired units ramp up to counterbalance this effect.
- Large hydro dams are built (Queensberry, Tuapeka, North Bank Tunnel (NBT) and Luggate).
- The share of energy from wind reaches 15 per cent in 2040 (Figure 33), up from two per cent in 2010 (Figure 31). The maximum value of 20 per cent is not reached in this scenario. Two new CCS coal-fired stations increase coal-powered generation's share between 2010 and 2040.

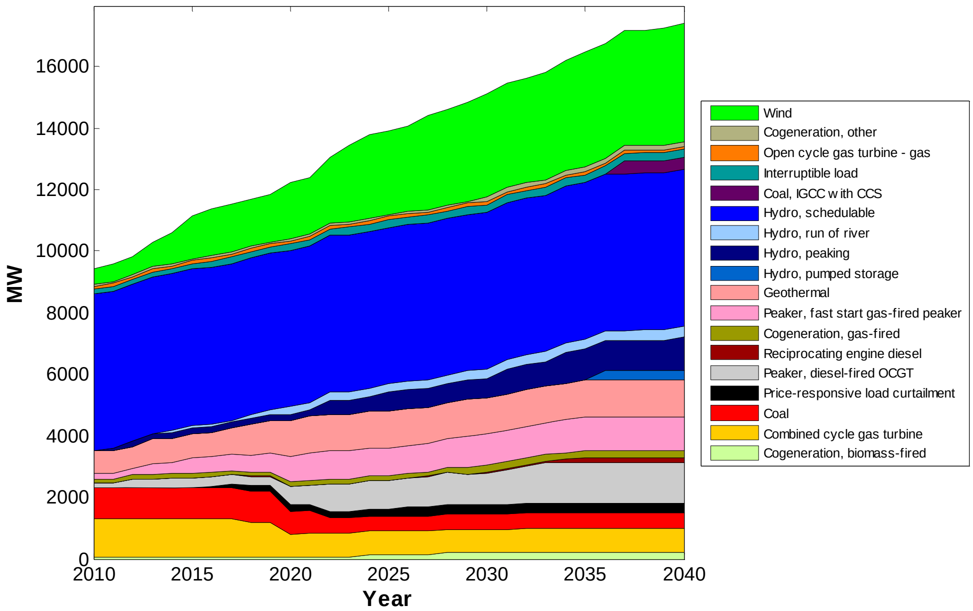
Figure 33 Energy share by fuel in 2040—Sustainable path scenario



7.3 2010 SI wind scenario

Figure 34 illustrates the installed capacity by year and technology and Figure 35 shows the energy share by fuel in 2040 for the 2010 SI wind scenario. The installed capacity by fuel is shown in Appendix 11 Figure 52. The energy by technology and by year is shown in Appendix 13 Figure 62 and the energy by fuel is shown in Appendix 12 Figure 57.

Figure 34 Installed capacity by technology by year—2010 SI wind scenario

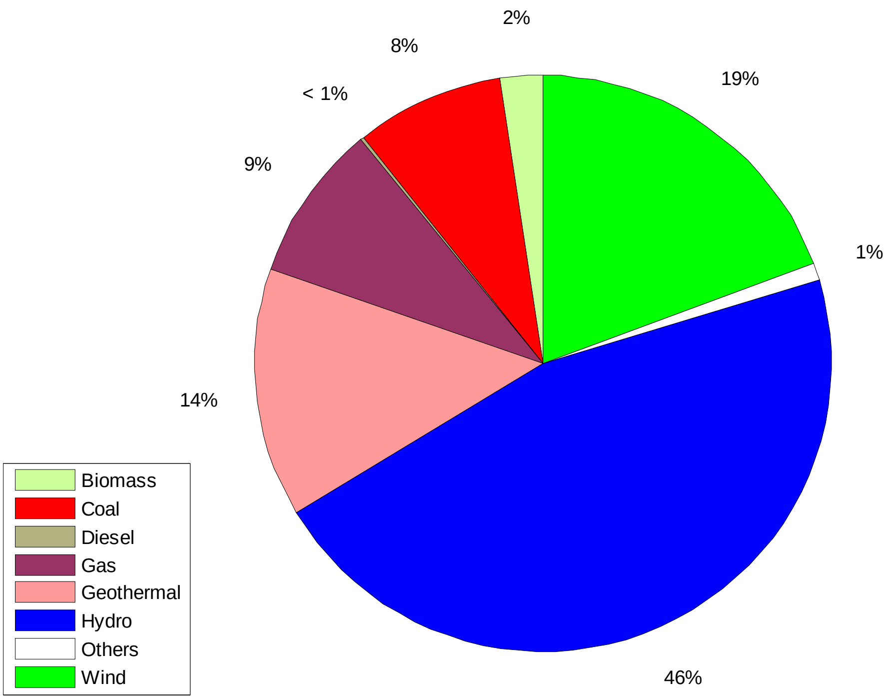


The key features of the 2010 SI wind scenario are as follows.

- As in the 2010 Sustainable path scenario, the combination of a high carbon price and a high gas price results in renewable projects being cost-effective relative to thermal generation. As a result, in this scenario Otahuhu B is decommissioned in 2020 together with some Huntly units in 2020 and 2022.
- Wind generation of 1000 MW is assumed to be built in the lower South Island including Project Hayes, Mahinerangi, and Kaiwera Downs between 2011 and 2016. These have been forced into the stack rather than selected by GEM as it may be easier to gain wind farm consent in the South Island than in other locations selected by GEM on economic factors alone. For the period after 2016, no wind farms were forced in.

- Between 2030 and 2040 wind energy reaches 20 per cent of total generation (see Figure 35), the limit GEM accepts at present.
- In comparison with other scenarios, 2010 SI wind requires extra peaking capacity partially because of wind intermittency (Figure 82 and Figure 83).
- As in the 2010 Sustainable path scenario, extensive new wind generation is developed, with over 3000MW installed by 2030 (Figure 76).
- As in the 2010 Sustainable path scenario, gas price increases from 2015, leading to a decrease in CCGT use until the decommissioning of Otahuhu B in 2020. Existing coal-fired units ramp up to counterbalance this change.
- There is a significant amount of new hydro generation, with 1000MW of new capacity by about 2030, mostly in the lower South Island.
- Geothermal development is less (exogenous decision) than in the 2010 Sustainable path scenario, with around 1200MW installed by 2020 (see Figure 79) but no more constructed thereafter.
- Demand-side response contribution is relatively small, but still assists in meeting peak demand.
- Even in the scenarios involving renewables, the energy share from hydro generation in 2040 (Figure 33 and Figure 35) is expected to decrease by approximately 10 per cent compared with the 2010 level (Figure 31). The greater diversity could help New Zealand to cope better with dry-year security.

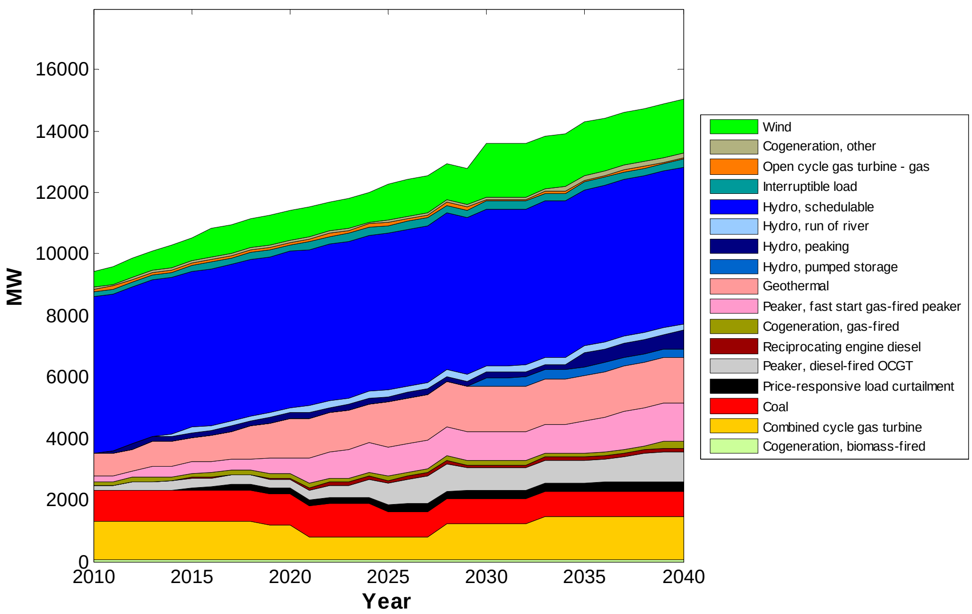
Figure 35 Energy share by fuel in 2040—SI wind scenario



7.4 2010 Medium renewables scenario

Figure 36 illustrates the installed capacity by technology and year and Figure 37 illustrates the energy share by fuel in 2040 for the 2010 Medium renewables scenario. Capacity and energy by fuel are shown in Appendix 11 Figure 53 and Appendix 12 Figure 58. The energy by technology and by year is shown in Appendix 13 Figure 63.

Figure 36 Installed capacity by technology by year—2010 Medium renewables scenario

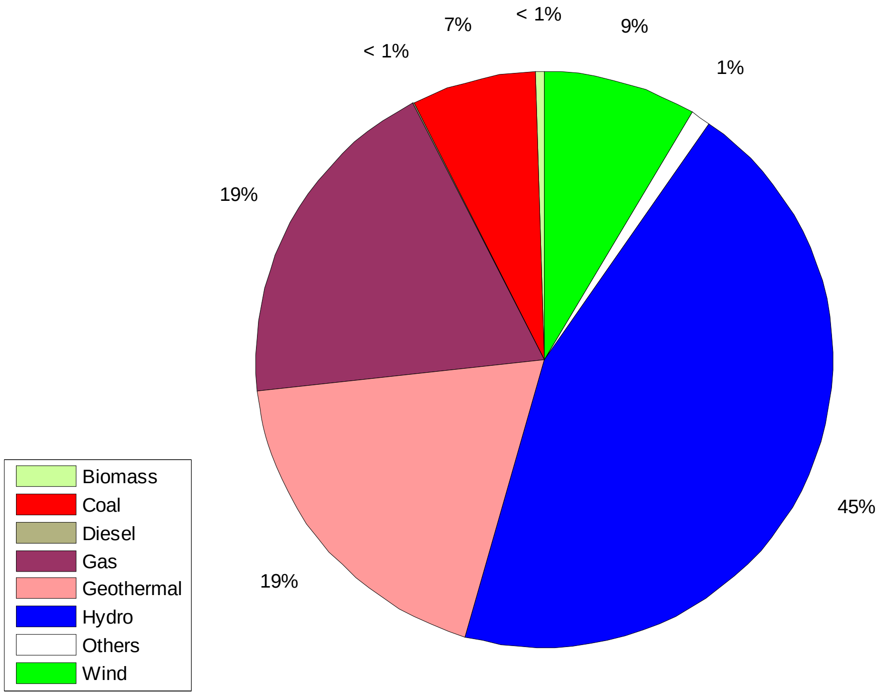


Key outputs of the 2010 Medium renewables scenario are as follows.

- Because of phasing-out of the Tiwai aluminium smelter around 2025, the 2010 Medium renewables scenario has low cumulative installed capacity (see Appendix 17 Figure 90).
- A coal-fired station is commissioned in 2022.
- Gas production decreases, owing to a lack of major discoveries in the last couple of years. As a result, one CCGT is decommissioned in the early 2020s. But when gas becomes available again (from the late 2020s) three new CCGTs are built;
- Renewable development is still strong, with about 1700MW of wind, 1400MW of geothermal, and 1000MW of new hydro installed.

- There is a requirement for gas-peaking generation in the 2020s, with the removal of the very flat Tiwai load.

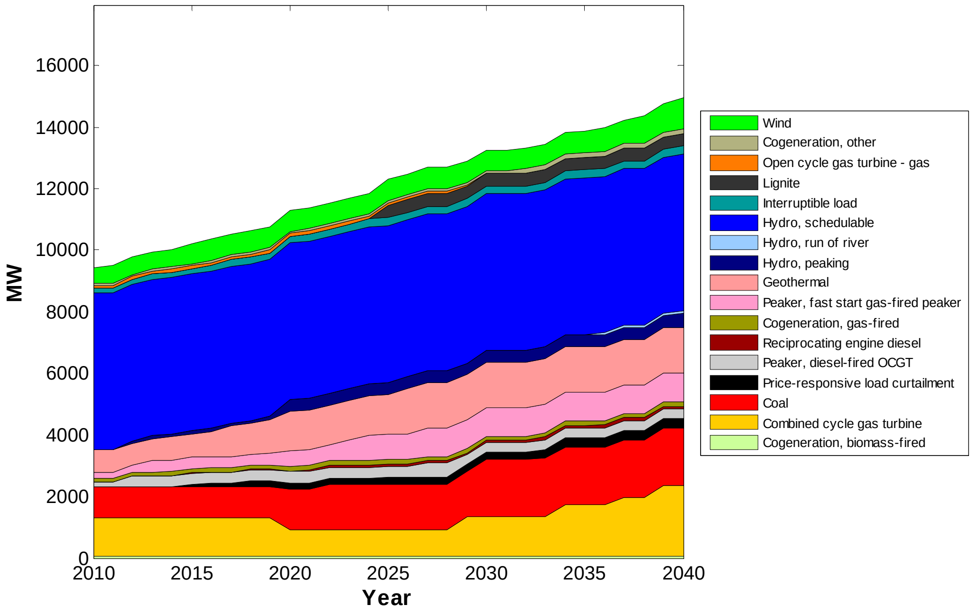
Figure 37 Energy share by fuel in 2040—2010 Medium renewables scenario



7.5 2010 Coal scenario

Figure 38 and Figure 39 present the installed capacity by technology by year and the energy share by fuel in 2040 for the 2010 Coal scenario. The capacity and energy by fuel are shown in Appendix 11 Figure 54 and Appendix 12 Figure 59. The energy by technology and by year is shown in Appendix 13 Figure 64.

Figure 38 Installed capacity by technology by year—2010 Coal scenario



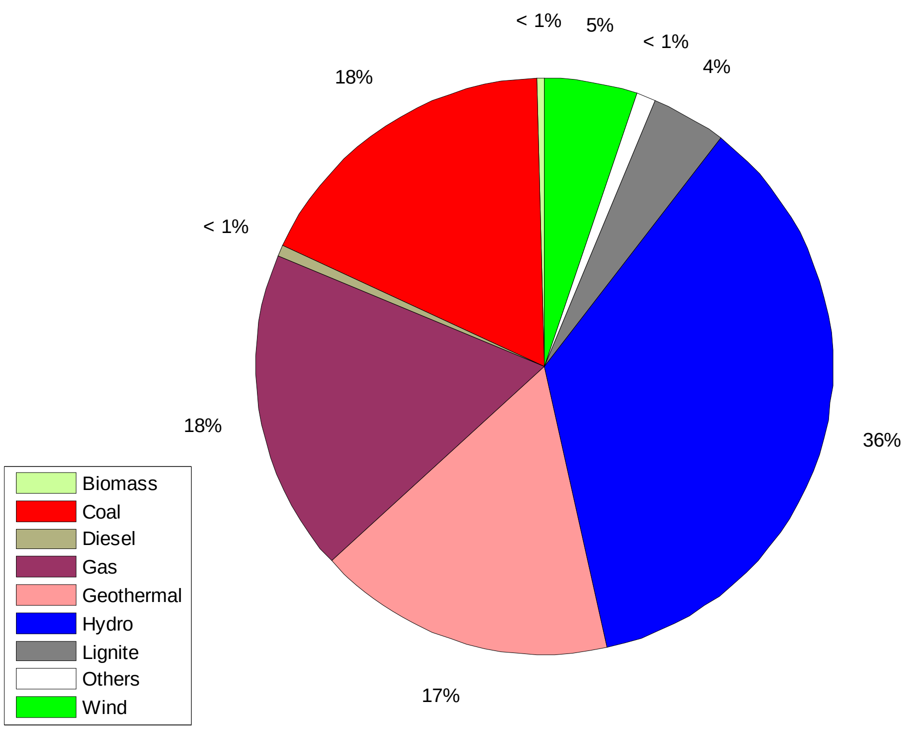
The principal outcomes of the 2010 Coal scenario are as follows.

- With a low carbon charge[67] and sufficient gas available after 2030, thermal generation is favourable;
- New coal- and lignite-fired generation have major roles to play in this scenario. One coal-fired unit at Huntly is decommissioned but the three others are refurbished. More efficient new plants, including 1100MW of coal plant (in the North Island) and a 400 MW lignite plant (in the South Island), are installed by 2030, resulting in high sectoral greenhouse emissions (see Figure 43).

[67] The carbon charge ($20/t in this case) is not high enough to cause substitution away to renewables.

- HVDC transfer is marginal, caused by baseload lignite and coal generation in both islands (see Figure 74).
- There is extensive geothermal and some hydro development, but little new wind.
- The output of existing hydro generation is curtailed due to difficulties in obtaining water rights.
- As in 2010 Sustainable path, gas production decreases with lack of major recent discoveries resulting in one CCGT decommissioned in the early 2020s. But four new CCGTs are built when gas becomes available again from the late 2020s.
- The energy share of hydro in 2040 has dropped by nearly 20 per cent and has been replaced mainly by coal-fired stations.

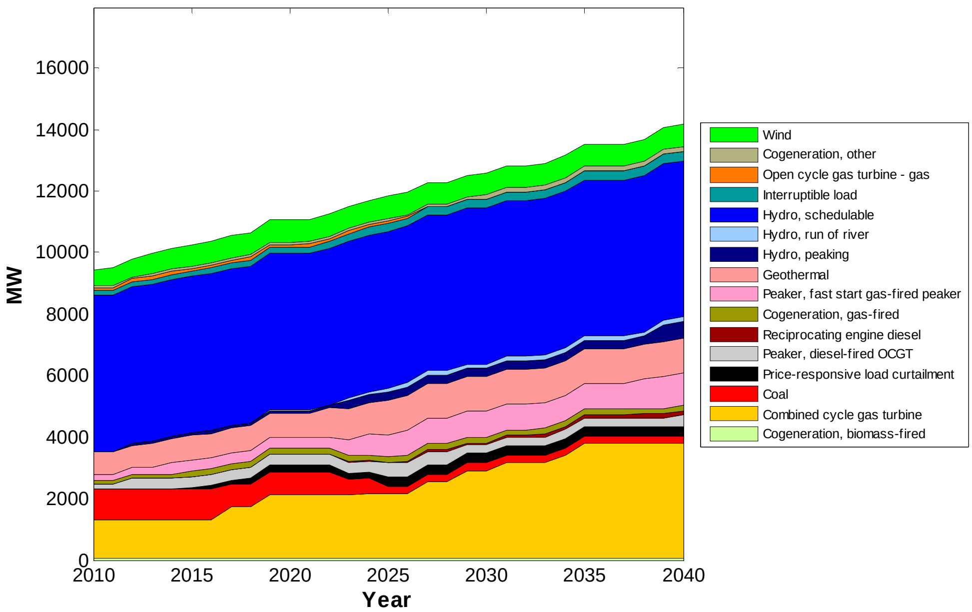
Figure 39 Energy share by fuel in 2040—2010 Coal scenario



7.6 2010 High gas discovery scenario

Figure 40 presents the installed capacity by technology by year and Figure 41 presents the energy share by fuel in 2040 for the 2010 High gas discovery scenario. Appendix 11 Figure 55 shows capacity by fuel. Appendix 13 Figure 65 shows energy by technology and Appendix 12 Figure 54 shows energy by fuel.

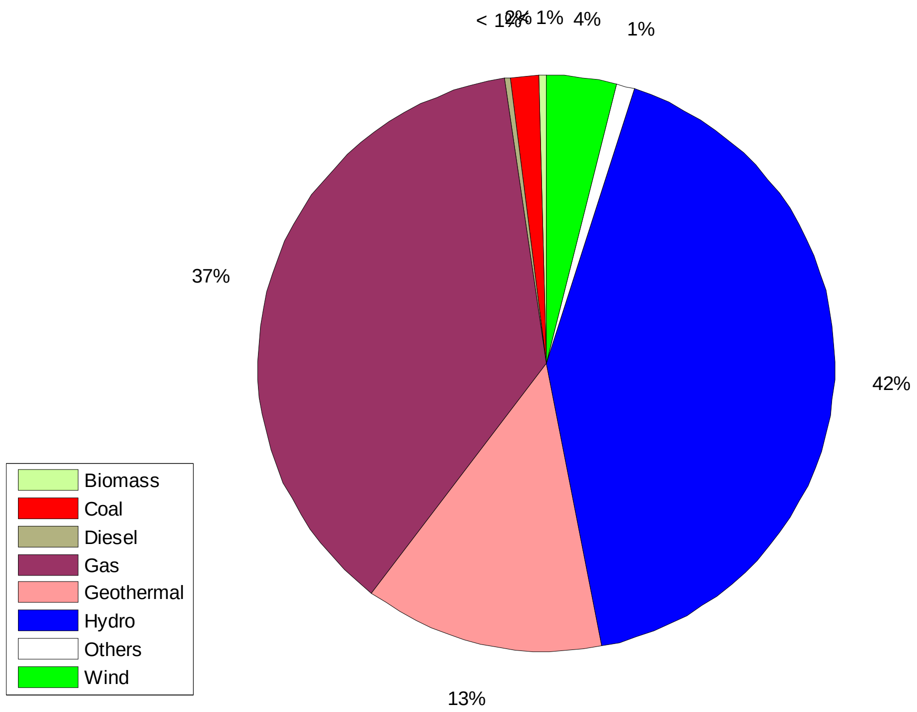
Figure 40 Installed capacity by technology by year—2010 High gas discovery scenario



The main outputs of the 2010 High gas discovery scenario are as follows.

- With a low gas price of $8/GJ and a moderate carbon charge of $40/t, gas generation is favourable. Four new CCGTs are installed by 2030, with gas forming a major component of electricity supply.
- With a low gas price and plenty of gas available, Huntly becomes uneconomic. Three units are closed by 2025.
- There is some geothermal and hydro development, but little new wind.
- The great majority of new plants are scheduled for construction in the North Island, so relatively little energy is transmitted northwards over the HVDC link (Figure 44).

Figure 41 Energy share by fuel in 2040—2010 High gas discovery scenario



7.7 Further discussion

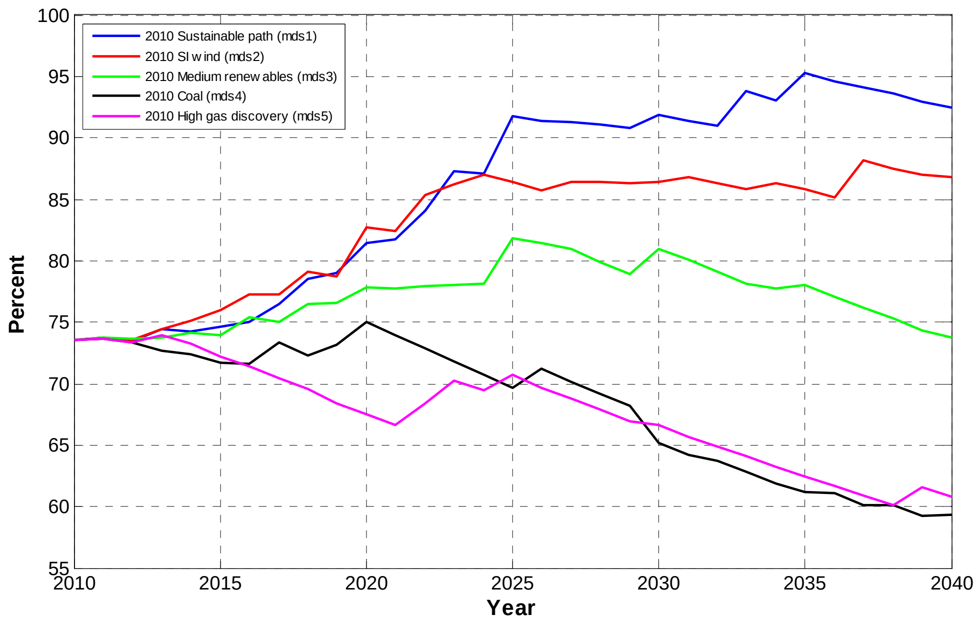
This section compares and contrasts several other key aspects of the scenarios.

- Projected proportion of electricity produced by renewables
- Projected greenhouse gas emissions
- Implications for HVDC transfers

7.7.1 Renewable percentage

The projected proportion of electricity produced by renewable generation is the key factor. Renewable generation fuels are hydro, geothermal, wind, biomass, solar, and marine, but not gas, coal, or diesel. The exception is thermal generation with carbon sequestration, which is considered to be renewable because greenhouse emissions are relatively low. The renewable generation percentage is plotted in Figure 42. It should be noted that these renewable generation percentages represent averages over inflow sequences. The actual percentage would be lower in a dry year, but higher in a wet year. In developing the scenarios, the Commission is not trying to meet any specific renewables target. It is the input assumptions that lead to more or fewer emissions in each scenario.

Figure 42 Renewable energy percentage for each of the five scenarios



In the early years (2010–2015), energy from renewables drops in most scenarios, even though most of the new installed capacity is coming from wind and geothermal generation. The financial crisis, uncertainty around gas supply, and carbon charge uncertainty have complicated investment decisions. Therefore, to meet the assumed increased demand in the next five years, existing thermal generations have to ramp up, assuming average inflow years. In the 2010 Sustainable path scenario, thermal generation stays at roughly the current production as in this scenario new lower South Island wind (1000MW) pushes renewable energy up.

The scenario involving most renewables is the 2010 Sustainable path, reaching approximately 90 per cent renewable generation by 2025. The 2010 SI wind scenario is over 85 per cent renewable from 2025 onwards. The 2010 Medium renewables scenario is over 75 per cent after 2020.

The 2010 Coal and 2010 High gas discovery scenarios have relatively high contributions from thermal generation, with renewable percentages dropping below the 70 per cent range after 2025.

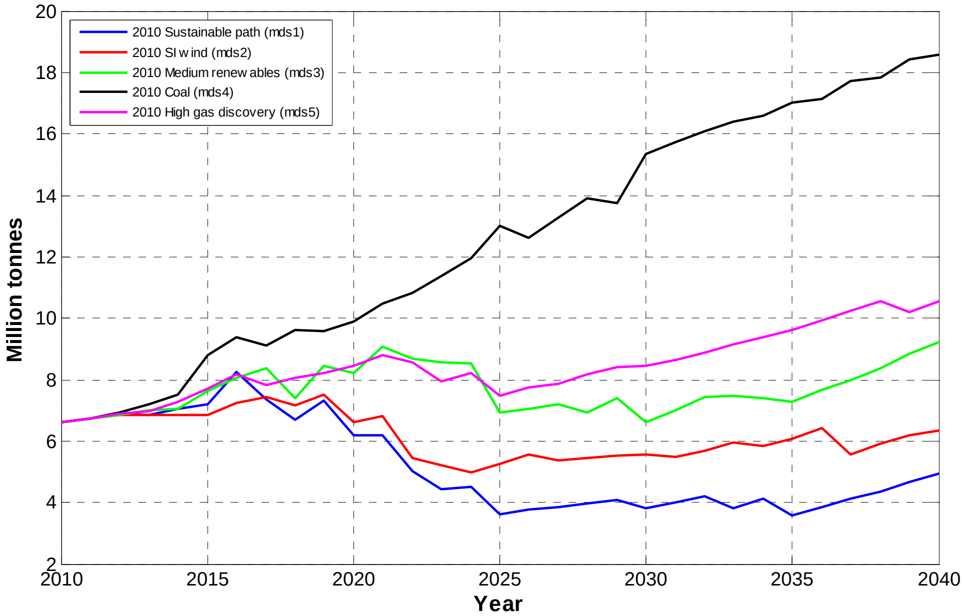
7.7.2 Electricity-sector greenhouse gas emissions

Projections of sectoral greenhouse gas emissions are plotted in Figure 43. Again, these are averages over inflow sequences. Details of the greenhouse gas emissions by technology are shown in Appendix 14.

The 2010 Sustainable path and 2010 SI wind scenarios predict major reductions in sector greenhouse emissions by 2025. Between 2025 and 2040, levels increase slightly, owing to the high utilisation rate of the existing thermal plants.

The 2010 Medium renewables scenario projects sectoral emissions increasing by 2020 before dropping to the 2010 levels by 2030. Levels then stay relatively constant.

Figure 43 Electricity-sector greenhouse gas emissions for the five scenarios



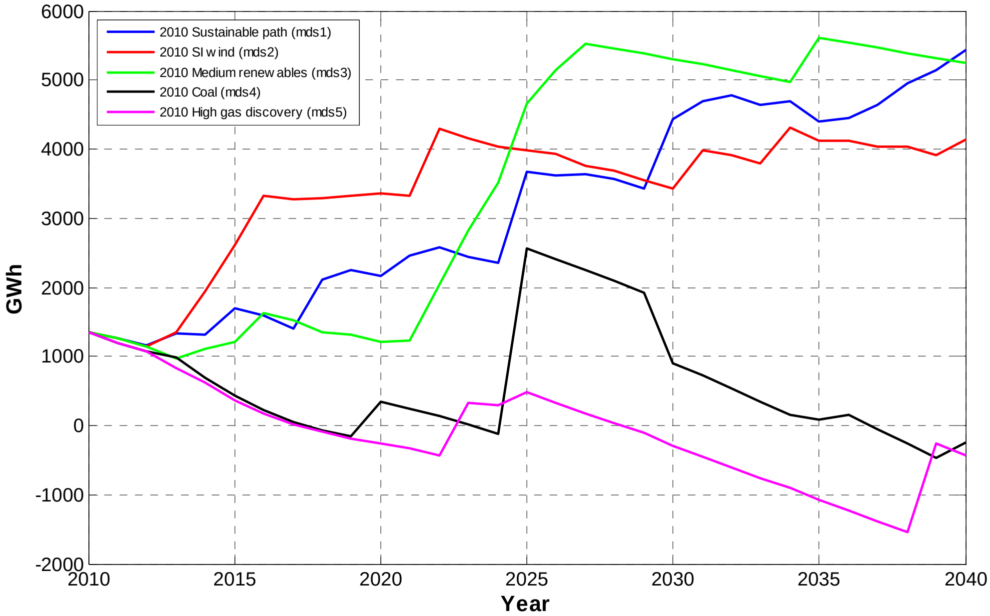
The 2010 High gas discovery scenario shows an increase in sectoral emissions (about 25 per cent of 2010 levels by 2030). This is driven by increased use of gas for electricity generation.

The 2010 Coal scenario shows a significant increase in sectoral emissions after 2015, as new coal and lignite generation comes online.

7.7.3 HVDC transfers

Figure 44 presents the net annual inter-island HVDC transfers in GWh for the five scenarios. Appendix 15 provides the northward and southward transmission and losses by year for the five scenarios.

Figure 44 Net annual inter-island HVDC transfers



In most scenarios the average net transfer (over inflow sequences) is northwards, though in dry years a much larger southwards transfer would be expected.

The 2010 SI wind scenario has the highest northwards flow up to 2025, with new renewable generation constructed in the lower South Island. After 2020 the new generation mix is more evenly distributed across the two islands.

The 2010 Sustainable path scenario has increasing northwards transfer from 2015 onwards, mainly caused by new hydro generation.

In the 2010 Medium renewables scenario, northwards flow increases significantly in the 2020s, caused by the phasing-out of the Tiwai smelter.

The 2010 Coal scenario has very low northwards flow in the early 2020s, with new coal-fired stations in the North Island. The new lignite plant in the South Island initially steeply increases the northward transfer and then after 2025, the net transfer drops again to zero.

2010 High gas discovery has relatively low northwards flow throughout, with a high proportion of new generation being North Island gas or geothermal plant. The transfer goes southwards from 2030 onwards.

The potential increase in transfer capability of the HVDC link to 1400MW has not occurred in any of the scenarios.

7.7.4 Peak security and balancing intermittent generation

As in the 2008 SOO, construction of new generation and demand-side response in the scenarios is driven in large part by the need to meet peak demand. The GEM model includes capacity constraints (Section 6.3.2) that:

- prefer mid-order generation over baseload, and baseload over intermittent generation, all else being equal;
- bring in peaking generation (diesel- and gas-fired peakers, pumped hydro, and augmentations to increase the capacity of existing hydro schemes); and
- lead to increased demand-side response at peak times.

Firm capacity by scenario is shown in Figure 91. Firm capacity is defined in GEM as the product of nameplate capacity and a technology-specific peak contribution factor. The capacity constraints (North Island and national) result in firm capacity tracking upwards with increases in peak demand that drives the construction of firm peaking capacity.

It has been suggested that the peaking capacity requirements are too strict. Certainly they lead to a substantial amount of new capacity that contributes little bulk energy—notably thermal peakers, enhancements to the peak output of existing hydro schemes, and demand-side response. In all five scenarios, GEM builds roughly 400MW of peakers by 2015 (in addition to Contact Energy's recently commissioned plant at Stratford).

It is not clear whether this estimate of thermal peaking capacity is high or low. Future development will depend on many factors, including but not limited to:

- the security standard New Zealand requires;
- how this will be achieved;
- how much the demand-side will contribute to meeting peak;
- how easy it will be to integrate wind generation into the system;
- to what extent these peakers will be needed for dry-year security; and

- whether existing thermal generation will remain in operation.

At any rate, it is clear that if most new electricity supply is to be sourced from geothermal and wind generation (which cannot ramp up to meet peak), *and* peak demand continues to grow, *and* ageing thermals are eventually removed from the system, then new peaking capacity will be needed.

It should be noted that although the model includes a significant amount of thermal peaking generation in all scenarios, the modelled output of these peakers is relatively low. This might seem to imply that it would not be possible to recover the construction costs of these peakers through their wholesale market revenues, ie those plants would not be 'revenue-adequate'. (The corollary would be that the use of the peaking capacity constraint had resulted in the scheduling of plant that would not be built under a free market).

As discussed in the 2008 SOO, the Commission considers there are other explanations for the low load factors of peakers in the model. It therefore remains to be determined whether the build schedules produced by the model are revenue-adequate (see section 7.7.6), but it appears that the low modelled utilisation rates of thermal peakers should not be relied on when carrying out this analysis.

The MDP project, in particular scarcity pricing, and the transition to a capacity-constrained North Island system, could reasonably lead to greater peakiness in price than has been observed in the past. Such price peaks might be caused by the market settling on the demand-side, but could also be due to scarcity prices, or some exercise of market power. Thus, low capacity factor plant may well be revenue-adequate given a more peaky price duration curve in the future.

7.7.5 Generation costs

This section presents cost data for the generation scenarios.

The GEM model projects various types of costs, for each scenario, in each year, and over a range of inflow sequences.

- Generation capital expenditure (including connection costs)
- Fuel costs
- Generation operation and maintenance, for new projects only
- Costs of carbon to the generation sector
- Costs of carbon storage where applicable

- HVDC charges

GEM seeks the build schedule that minimises these costs, on a post-tax basis and discounted at eight per cent real. Generation capex enters the model as an annualised cost stream.

Modelled costs by scenario are shown in Figure 45 to Figure 49. For ease of interpretation, these show pre-tax costs, with generation capex represented on a lump-sum basis. All costs are expressed in real undiscounted dollars. The figures shown are averages over inflow sequences (in dry years, fuel and carbon costs would be higher than average).

Some types of supply-side costs are not modelled in GEM and therefore not included in these figures. Such costs include transmission upgrade costs, ancillary service costs, consenting costs, generator overheads, etc. HVDC charges are modelled in GEM but not shown in the figures.

Figure 45 Annual costs (mean, undiscounted, pre-tax)—2010 Sustainable path scenario

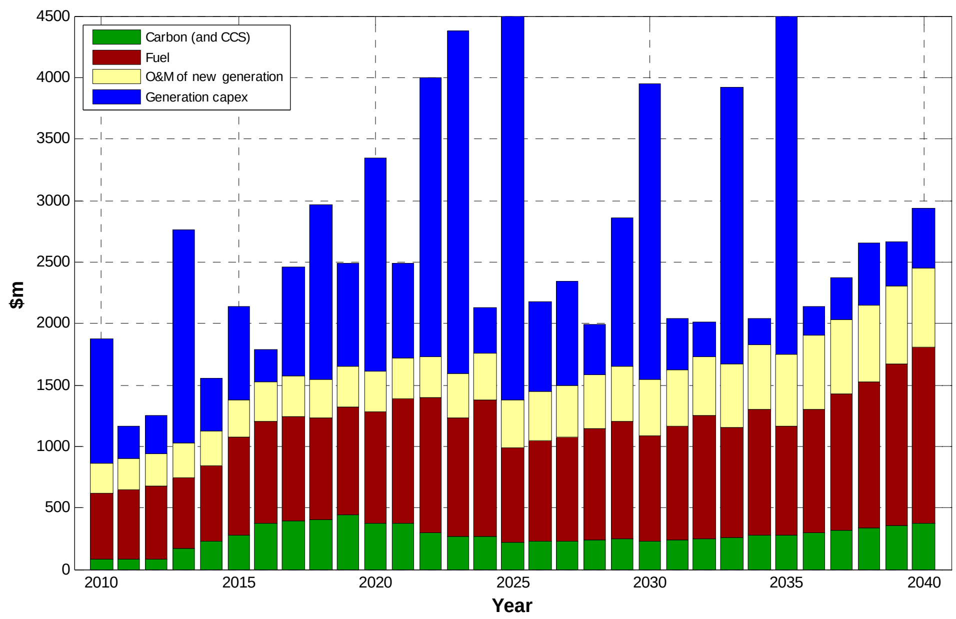


Figure 46 Annual costs (mean, undiscounted, pre-tax)—2010 SI wind scenario

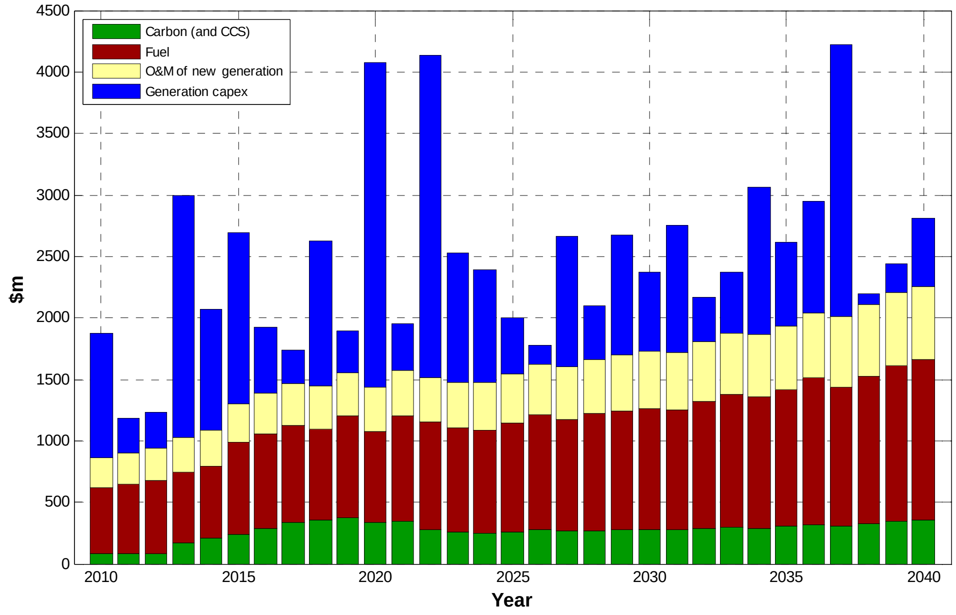


Figure 47 Annual costs (mean, undiscounted, pre-tax)—2010 Medium renewables scenario

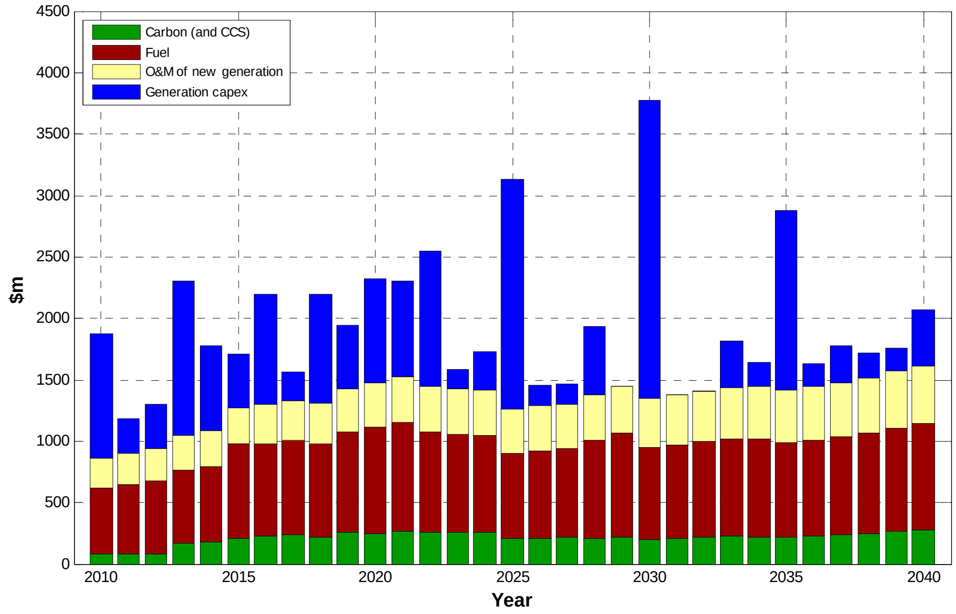


Figure 48 Annual costs (mean, undiscounted, pre-tax)—2010 Coal scenario

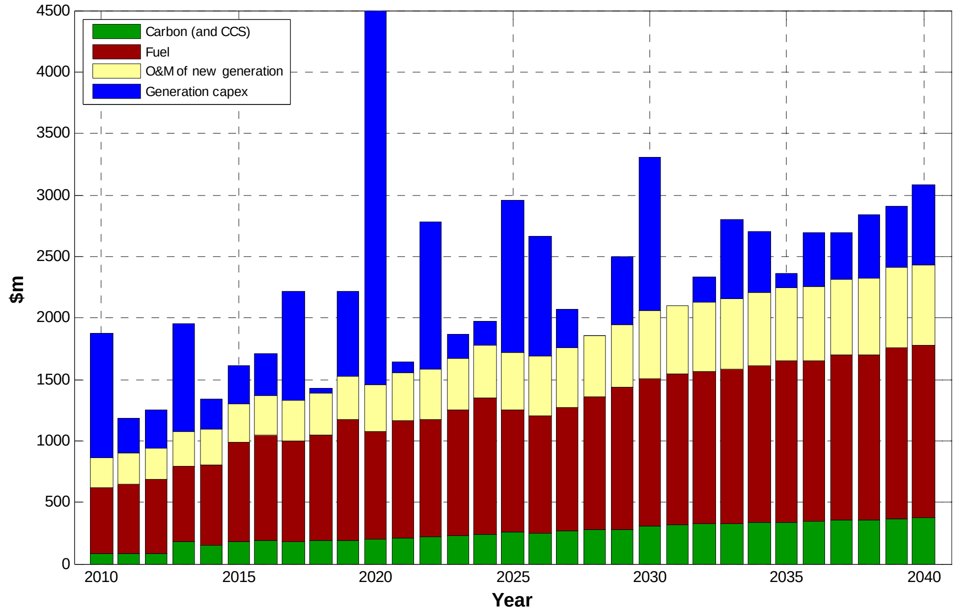
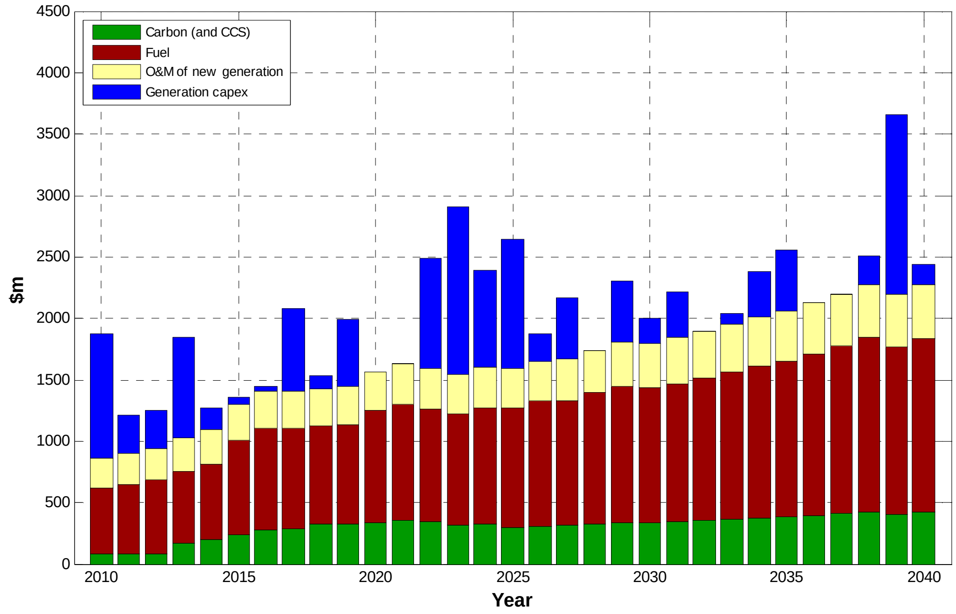


Figure 49 Annual costs (mean, undiscounted, pre-tax)—2010 High gas discovery scenario



Net Present Values (NPVs) of supply-side costs are shown in Table 16. A central discount rate of eight per cent is used.

These are post-tax costs. They include annualised generation capex, connection costs, O&M of new generation, fuel, electricity-sector carbon costs, and carbon storage costs where applicable. HVDC charges are included.

Table 16 NPVs of post-tax costs (mean over inflow sequences) in the generation scenarios

	2010 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery
Generation capex	10,044	9,695	6,999	6,592	4,688
Transmission capex	532	532	532	532	532
Fixed O&M (incl HVDC charge)	1,702	1,640	1,644	1,808	1,395
Variable O&M (incl fuel)	9,617	9,442	8,279	9,625	9,766
Total	**21,895**	**21,308**	**17,454**	**18,558**	**16,380**

Care should be taken in comparing costs between scenarios. In large part, the cost differences are driven by exogenous assumptions. For example:

- the high costs in the 2010 Sustainable path and 2010 SI wind scenarios are the result of high fuel and carbon prices;
- the low costs in the 2010 High gas discovery scenario are the result of low carbon and gas prices;
- the low costs in the 2010 Medium renewables scenario are partly due to the closure of the Tiwai smelter, which significantly reduces national electricity consumption.

In each scenario, the generation build plan presented is the least-cost response to the exogenous assumptions (given the GEM modelling framework). For instance, the extensive use of renewables in the 2010 Sustainable path and 2010 SI wind scenarios is the most economic way of producing electricity in an environment where carbon emissions are expensive and fossil fuels are scarce. So, rather than concluding that 'renewable generation is expensive', the SOO assesses that 'renewable generation is the best way of reducing supply-side costs in some scenarios'.

One reason for the high reliance on renewable generation in some of the scenarios is the modelled cost of greenhouse emissions. It is easy to show that, if New Zealand faces a cost for electricity-sector emissions, it is economic to pass that cost on to electricity generators. Failing to charge for carbon would result in more thermal generation, more emissions, and an overall higher cost for New Zealand.

GEM has been used to demonstrate this dynamic. An alternative set of scenarios has been created, with all inputs identical to the 2010 SOO scenarios, except that electricity generators do not have to pay for emissions. As expected, this results in:

- existing thermal generation staying in operation longer;
- more new fossil-fuelled generation being constructed; and
- more use of coal and less use of gas.

When the national cost of carbon emissions is excluded, this appears more optimal, but when national carbon costs are considered, the renewable option is more economic (Table 17).

Table 17 Effects of removing the carbon charge

		210 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery	Average
NPV of post-tax costs ($m, mean over inflow sequences, excludes any carbon charge)	With carbon charge	19,955	19,491	15,820	16,993	14,691	17,390
	Without carbon charge	19,901	19,402	15,742	17,000	14,607	17,330
	Difference	55	90	77	-7	85	60
NPV of national carbon costs ($m)	With carbon charge	1,981	1,862	1,500	1,541	2,021	1,791
	Without carbon charge	2,221	2,050	1,748	1,674	2,361	2,011
	Difference	-240	-189	-198	-132	-340	-220
Total NPV ($m)	With carbon charge	21,936	21,353	17,370	18,535	16,712	19,181
	Without carbon charge	22,122	21,452	17,491	18,674	16,968	19,341
	Difference	-186	-99	-121	-140	-255	-160

(Note, figures in this table are based on draft scenarios rather than the final scenarios published in this document. The effects on this analysis can be expected to be minimal.)

Removing the carbon charge on electricity generators has the potential to deliver cheaper electricity, but the avoided cost of renewables is outweighed several times over by the consequent cost of increased emissions.

Two features common to most of the scenarios are:

- extensive investment in geothermal generation; and
- significant investment in wind and/or large hydro generation in the lower South Island.

Geothermal generation is widely considered to be a very cost-effective option for New Zealand. Several geothermal projects are currently at various stages of the development process, and more are planned for the next few years. Geothermal generation may have the potential to supply the majority of New Zealand's new baseload throughout the next decade.

In 2009, the Commission approved Transpower's Wairakei Ring Investment Proposal (Wairakei upgrade). The Wairakei upgrade encompasses a new double circuit 220kV line from Wairakei to Whakamaru and related works. It is expected to be commissioned in 2013. The primary purpose of this economic investment is to unlock geothermal generation resources in the central North Island. The Wairakei upgrade passed the GIT, on the assumption that new geothermal generation is able to be constructed and dispatched at a lower cost than other new generation in New Zealand.

It also appears that there may be significant opportunities for renewable generation in the lower South Island. This part of the country seems to hold the most promise for development of large hydro schemes—Contact Energy has options for further development on the Clutha River, and Meridian Energy may proceed with the North Bank Tunnel project. All five market development scenarios envisage that at least one of these hydro schemes will proceed. There are also plans for large new wind farms in Otago and Southland.

In April 2010, the Commission published a notice of its intention to approve Transpower's Lower South Island Renewables Investment Proposal (LSI Renewables upgrade). The LSI Renewables upgrade encompasses duplexing and thermal upgrading of five line sections north of Roxburgh and south of Twizel and related works. It is expected to be commissioned in 2015. The primary purpose of this economic investment is to unlock wind and hydro generation resources in the lower South Island.

Once various transmission upgrades are complete, including the new Pole 3 of the inter-island HVDC link, new renewable generation in the central North Island and lower South Island will be able to contribute to meeting New Zealand peak demand. Geothermal generation can reasonably reliably support peak, and hydro generation backed by storage is very effective at meeting peak demand. Hydro generation can also contribute to the power system by balancing fluctuations in wind generation output. This contribution is not yet fully modelled in GEM, but will be one focus of future GEM development.

7.7.6 Revenue adequacy

The 2008 SOO included an analysis of revenue adequacy in its market development scenarios. This analysis sought to determine how high prices would have to be in each future year to allow generators to recoup the costs of their investments plus a reasonable margin of profit. This section updates the revenue adequacy analysis for the new scenarios.

The approach taken is, for each scenario, to determine a price path that would allow the costs of new generation plants to be recovered from the revenue of those plants. (An alternative would be to determine a price path that would allow the costs of existing *and* new generation to be recovered from generator revenues, but this was deemed unfeasible because of uncertainty about the extent of costs still to be recovered from existing generation projects.)

Revenue adequacy should hold not only for the overall portfolio of new plant, but also for each category of plant. Thus, it is asserted that under revenue adequacy:

- the costs of baseload plant should be recoverable from average prices;
- the costs of mid-order plant should be recoverable from prices during peak and shoulder periods; and
- some portion of the costs of peaking plant should be recoverable from prices during peak periods, although peaking plant could also earn revenue from providing ancillary services, exploiting inter-regional wholesale price differences, and/or being paid to act as transmission alternatives.

There are many price paths satisfying these requirements. One extreme example could be for all plants to earn *no* revenue until 2040 and then to earn a very large amount of revenue in the 2040 year. To narrow down the options, additional constraints are added, requiring revenue adequacy in each year and putting some conditions on the shape of the price duration curve.

On this basis, a revenue-adequate price path has been defined as a set of prices for each year, time period, load block, and inflow sequence that satisfies the following constraints in each year.

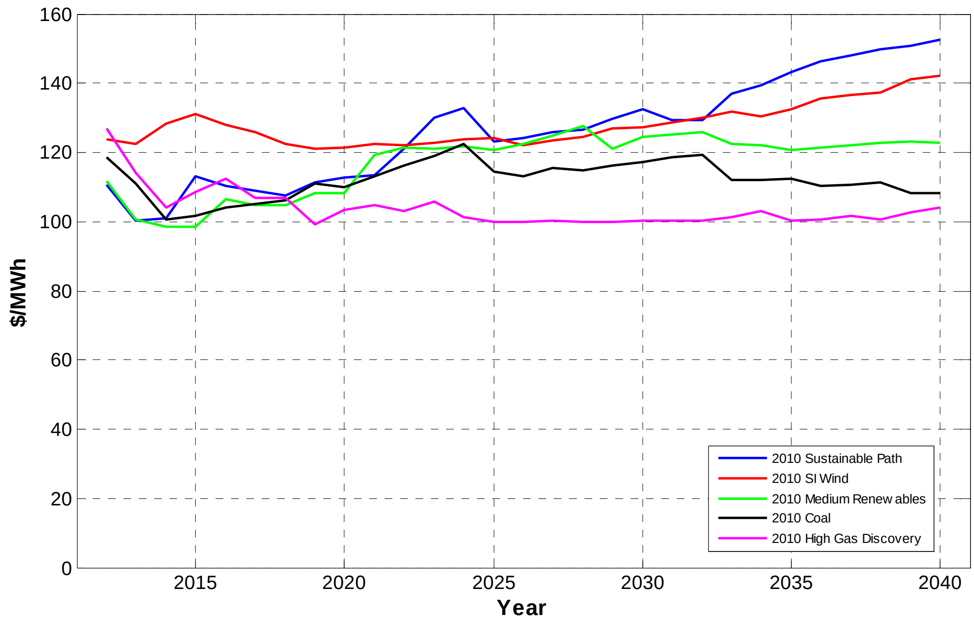
- The wholesale revenue (sum of output multiplied by Haywards price, less tax) obtained from new plant must exceed the total operating cost (post-tax, including that year's portion of the annualised capital costs) by at least a 10 per cent profit margin.

- The wholesale revenue obtained from new baseload plant must exceed their operating cost by at least a 10 per cent profit margin.
- The wholesale revenue obtained from new mid-order plant must exceed their operating cost by at least a 10 per cent profit margin.
- The wholesale revenue obtained from new peaking plant must exceed *half* their operating cost by at least a 10 per cent profit margin.

The resultant revenue-adequate price paths for the generation scenarios are shown in Figure 50. Note that the mean is time-weighted rather than demand-weighted—a demand-weighted mean would be higher.

Revenue-adequate prices before 2012 have not been estimated, because the projected amount of new generation in that period is not yet enough to provide a clear picture of new entrant costs. Revenue-adequate prices for 2012–2013 have been estimated but are derived from a relatively small number of new projects. Forecasts after 2013 benefit from being derived from a large pool of projects in all scenarios.

Figure 50 Revenue-adequate price paths for the generation scenarios



(Note, this Figure is based on draft scenarios rather than the final scenarios published in this document. The difference in price paths can be expected to be minimal.)

Over the 2015–2020 period, revenue-adequate prices range from $100 to $115/MWh. The exception is the 2010 SI wind scenario, where early out-of-merit developments lead to higher revenue requirements. However, this may be seen as a modelling artefact stemming from the way in which consented South Island wind projects have been 'forced' into the build schedule. An alternative way to model the development of these projects would have been to reduce their assumed cost so they were more economic than other generation options elsewhere; if this had been done, the 2010 SI wind scenario would have had a lower revenue-adequate price path.

Over the 2020–2030 period, revenue-adequate prices range from just over $110 to $130/MWh, except in the 2010 High gas discovery scenario, where low fuel prices drive relatively low-cost new thermal generation development.

In the very long term, revenue-adequate prices go as high as $150/MWh in the 2010 Sustainable path scenario, where fuel and carbon costs are high and new generation consists mainly of renewables backed by thermal peakers.

Beyond 2020, the most renewable scenarios have the highest revenue-adequate price paths. This is not because renewables are an expensive option, but because those scenarios have high gas and carbon prices[68]. Renewable development is the least-cost response to those conditions; with more thermal generation, costs and prices would be even higher.

In a competitive market, it could be expected that actual mean prices would not exceed these projections over an extended period (multiple years), since new entrant generators would be able to offer in at the revenue-adequate price level and still make a profit.

Actual mean prices might fall below the projected level. In this case, generators would not be able to recover the costs of their new plant. Owing to portfolio effects, however, it might still be optimal for them to continue to build new generation. The possibility of prices being less than the revenue-adequate level for extended periods of time can therefore not be ruled out.

68 Differences in carbon prices between scenarios explain some of the differences in revenue adequate price paths. If carbon prices were the same across all scenarios ($40/t from 2018), but build plans remained the same, then the main difference would be that the "Coal" price path would be substantially higher, reaching $120/MWh in 2022 and flattening at $125-130/MWh over 2024-2030.

8. The power systems analysis

8.1 Approach

Rule 9.1.1 of section III of part F of the Rules requires the SOO to include an analysis of the performance of the power system against the GPA and the GRS. This section summarises the results of the PSA.

The purpose of the SOO is to enable identification of potential opportunities for efficient management of the grid including investment in upgrades and transmission alternatives.[69] The Rules also provide that in preparing the SOO the Commission must have regard to the principle of meeting the reasonable requirements of Transpower, investors in generation, other participants, end-use consumers, and those interested in evaluating transmission alternatives.

The PSA contributes to the purpose and furthers the principle by identifying when the grid, in any given scenario (that is, the GPA) will no longer meet the GRS.

The point at which the grid is anticipated to no longer meet the GRS represents an opportunity for efficient management of the grid, including investment in upgrades and transmission alternatives. The opportunities signalled in the SOO are strictly transmission opportunities, but the Commission emphasises that in some situations opportunities for investment in alternatives to transmission may arise at the same time.

Therefore, in summary, the PSA:

- identifies the characteristics and capabilities of the existing transmission network during peak demand periods;
- assesses the ability of the existing transmission network to meet the GRS under each generation scenario over the relevant period of the GPA (30 years);
- identifies transmission limitations and constraints within regions that may require investment in order to continue to meet the GRS. This analysis focuses on forecasting supply and demand within regions, and on when constraints are likely to become binding; and
- identifies rudimentary, long-term, least-cost transmission opportunities for each scenario.

[69] Operational measures include special protection systems (SPSs), bus splitting, and intertripping.

Only significant committed projects and transmission opportunities are used in the PSA Relatively minor augmentations, such as supply transformer upgrades, do not form part of the PSA. Additional details of the approach and assumptions taken in carrying out the PSA are given in Appendix 18.

Section 8.2 summarises the key transmission opportunities identified for the North Island and section 8.3 gives those for the South Island. Further details are given in Appendix 19.

8.2 North Island power systems analysis

The North Island maximum demand is forecast to increase from around 4900MW in 2010 to around 8700MW in 2040. The increase, as well as a portion of the existing demand, is forecast to be supplied by increased North Island generation in all scenarios. The scenarios include net[70] new North Island generation in the range 4500MW (High gas discovery) to 6700MW (South Island wind).

Major transmission projects approved by the Commission include:

- NAaN;
- NIGU;
- Wairakei Ring augmentation; and
- HVDC Pole 3.

These projects will significantly contribute to the capability of the grid to meet the GRS.

Further transmission opportunities have been identified by the PSA, depending on the generation scenario. The following list summarises the key opportunities identified by the Commission's modelling. Only significant opportunities common to multiple scenarios are included here. Full details, broken up by region, are given in Appendix 19 with additional data on timing and relevant scenarios. Key transmission opportunities identified were as follows.

- Northland
  - Improved transmission security to Dargaville by 2015

[70] All scenarios include some decommissioning of existing North Island generation, in the range 1300MW (South Island wind) to 2100MW (Sustainable path). Total new North Island generation is in the range 6000MW (High gas discovery) to 8000MW (Sustainable path and South Island wind). The 'net' new generation is equal to the total new generation minus the decommissioned generation.

- Potential opportunity for additional reactive support at Maungatapere, depending on future generation
- Potential opportunity for additional 110kV transmission capacity between Maungatapere, Kaikohe and Marsden, depending on future generation
- Reactive support at Kaikohe towards the end of the study period

- North Auckland
  - Additional 220/110kV interconnection capacity at Henderson by 2035, with scope for operational measures around 2020
  - Additional 110kV transmission capacity between Henderson and Hepburn Road by 2035 and between Henderson and Wellsford by 2040
- Auckland
  - Additional 220kV capacity between Pakuranga and Penrose around 2025
  - Additional 220/110kV interconnection capacity at Otahuhu by 2030, Penrose by 2035, and Hobson Street by 2035
  - Additional 110kV transmission capacity between Otahuhu, Wiri, and Bombay, with timing dependent on future generation
- Waikato
  - Additional 220/110kV interconnection capacity at Whakamaru by 2015;
  - Additional 110kV transmission capacity in the vicinity of Arapuni and Hamilton, including between Hamilton and Bombay, around 2025
  - Reactive support at Waihou by 2035
- Wairakei
  - Following the approved Wairakei Ring augmentation, additional 220kV capacity between Atiamuri and Ohakuri by 2040, with scope for operational measures initially (around 2025)
- Bay of Plenty
  - Additional 110kV capacity between Kinleith, Lichfield, and Tarukenga by 2025

- Additional 110kV capacity between Kaitimako, Poike, and Mt Maunganui by 2025, with opportunities for operational measures by 2015
- Additional 110kV capacity between Rotorua and Tarukenga by 2030
- Additional 110kV capacity between Edgecumbe and Kawerau by 2020, with scope for varying operational measures later in the study period

- Hawke's Bay
  - Additional 220/110kV interconnection capacity at Redclyffe by 2035, with scope for operational measures depending on future generation
  - Additional 110kV transmission capacity between Gisborne and Tuai around 2030
- Central North Island
  - Additional 220/110kV interconnection capacity at Bunnythorpe, depending on future generation, by 2035
  - Additional 110kV capacity between Bunnythorpe and Woodville (scope for operational measures) around 2020
  - Additional 220kV capacity between Bunnythorpe and the Central North Island around 2035
- Taranaki
  - Additional 220kV transmission capacity between Stratford, Brunswick, and Bunnythorpe around 2030
  - Additional 220/110kV interconnection capacity at Stratford by 2040
- Wellington
  - Additional 220/110kV interconnection capacity at Haywards by 2025
  - Additional 110kV transmission capacity north of Wellington
  - Reactive support at Paraparaumu by 2015

8.3 South Island Power Systems Analysis

The South Island maximum demand is forecast to increase from around 2350MW in 2010 to around 3250MW in 2040. Depending on the scenario, the increase is forecast to be supplied by either increased South Island generation or a decrease in HVDC transfer due to increased North Island generation. The scenarios include new South Island generation in the range 480MW (High gas discovery) to over 2300MW (Sustainable path).

As the bulk of the generation growth in all scenarios occurs in the North Island, only limited transmission opportunities were identified in the South Island by the PSA. The following list summarises the key opportunities identified in the South Island. Only significant opportunities common to multiple scenarios are included here. Full details, by region, are presented in Appendix 19 with additional data on timing and relevant scenarios.

Key transmission opportunities identified were as follows.

- Canterbury and South Canterbury
  - Transmission support for the Upper South Island around 2025 and later
  - Additional 220kV capacity into Ashburton and between Ashburton and Islington
  - Dynamic reactive support at Ashburton
  - Additional 220kV transmission capacity between Benmore and Ashburton
  - Additional 220/66kV interconnection capacity in Christchurch, including Bromley and Springston by 2015 and further interconnection capacity for Bromley and Islington around 2035
  - Additional 220/66kV interconnection capacity at Timaru by 2030
  - Additional 66kV transmission capacity between Islington and Springston around 2025, with scope for operational measures initially
  - Reactive support at Oamaru by 2015
- Otago/Southland
  - Additional 220/110kV interconnection capacity at Edendale by 2025, to accommodate a 400MW lignite generation plant in the Coal scenario

– Additional 220/110kV interconnection capacity at Roxburgh, occurring only in conjunction with substantial generation development envisaged for the Otago/Southland region, around 2020

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Appendix 1 After diversity maximum demand peak forecasts

Table 18 Region total at Island peak (prudent)—North Island (MW)

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2009	874	1425	575	448	278	328	143	677	4747
2010	908	1469	587	458	283	335	145	692	4876
2011	939	1518	601	465	288	342	147	709	5010
2012	970	1571	615	476	297	353	149	732	5164
2013	1009	1623	633	487	306	363	154	751	5326
2014	1032	1674	646	497	315	373	156	768	5461
2015	1056	1725	659	507	319	379	158	784	5587
2016	1078	1774	671	515	322	382	159	798	5701
2017	1101	1829	684	525	325	386	160	813	5825
2018	1123	1885	697	535	328	389	161	828	5945
2019	1144	1940	710	546	330	392	162	842	6066
2020	1167	1996	723	556	333	395	163	856	6188
2021	1189	2051	735	567	335	398	163	869	6308
2022	1212	2105	747	578	338	401	164	883	6429
2023	1236	2158	759	588	341	405	165	896	6547
2024	1260	2211	770	598	343	409	166	909	6667
2025	1285	2265	782	609	346	412	167	922	6787
2026	1309	2317	793	618	349	416	168	935	6905
2027	1333	2368	803	628	352	419	169	947	7018
2028	1358	2420	814	638	355	423	169	959	7136
2029	1384	2473	824	647	357	426	170	972	7254
2030	1409	2527	835	657	360	430	171	984	7373
2031	1437	2583	846	668	363	433	172	998	7501
2032	1464	2639	857	679	366	437	173	1010	7625

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2033	1491	2694	868	689	369	440	174	1023	7748
2034	1518	2752	879	700	372	444	175	1035	7876
2035	1546	2810	890	711	375	447	176	1048	8004
2036	1575	2870	902	722	377	451	176	1061	8134
2037	1604	2931	913	733	380	455	177	1074	8267
2038	1633	2992	925	745	383	458	178	1087	8400
2039	1662	3055	936	756	386	462	179	1100	8537
2040	1692	3119	948	768	389	465	180	1113	8674

Table 19 Region total at Island peak (prudent)—South Island (MW)

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2009	224	57	797	99	1127	2303
2010	232	60	817	103	1151	2363
2011	240	61	842	107	1175	2425
2012	250	76	868	112	1199	2505
2013	258	77	894	117	1221	2567
2014	264	78	918	120	1236	2615
2015	268	79	938	122	1244	2650
2016	270	80	954	124	1247	2674
2017	272	80	970	125	1248	2695
2018	273	81	984	126	1248	2711
2019	273	81	997	127	1248	2726
2020	274	82	1011	127	1248	2742
2021	275	82	1024	128	1248	2758
2022	277	82	1039	129	1250	2777
2023	278	83	1053	130	1252	2797
2024	281	83	1069	132	1255	2820
2025	283	84	1085	133	1259	2844
2026	285	84	1101	135	1263	2868
2027	288	84	1117	136	1266	2891
2028	290	85	1133	138	1270	2916
2029	293	85	1150	139	1275	2941
2030	295	85	1167	141	1279	2967
2031	298	86	1185	143	1284	2995
2032	301	86	1202	144	1288	3021
2033	304	87	1219	146	1292	3047
2034	307	87	1236	148	1297	3074
2035	309	87	1253	149	1301	3101

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2036	312	88	1271	151	1306	3128
2037	315	88	1288	153	1310	3155
2038	318	89	1306	155	1315	3182
2039	321	89	1324	156	1320	3210
2040	324	89	1342	158	1324	3238

Table 20 Region total at Island peak (mean)—North Island (MW)

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2009	851	1351	553	432	272	318	138	655	4569
2010	877	1391	563	438	275	323	139	668	4676
2011	904	1432	574	445	278	329	140	682	4783
2012	932	1476	586	453	284	337	142	697	4907
2013	958	1520	597	461	290	344	145	712	5028
2014	982	1564	609	470	295	351	147	727	5146
2015	1006	1612	621	479	300	356	149	742	5265
2016	1027	1658	632	487	302	360	150	756	5372
2017	1048	1710	645	496	305	363	151	770	5488
2018	1069	1761	657	506	307	366	151	784	5601
2019	1089	1813	669	515	310	369	152	797	5715
2020	1111	1866	681	526	312	372	153	810	5830
2021	1132	1917	693	536	314	375	154	823	5943
2022	1154	1968	704	546	317	378	155	836	6057
2023	1176	2017	715	555	319	381	155	848	6167
2024	1200	2067	726	565	322	384	156	861	6281
2025	1223	2117	737	575	325	388	157	873	6394
2026	1247	2165	747	584	328	391	158	885	6505
2027	1269	2213	757	593	330	394	159	896	6611
2028	1293	2262	767	602	333	398	160	908	6723
2029	1317	2311	777	611	335	401	160	920	6833
2030	1341	2361	787	621	338	404	161	932	6945
2031	1368	2414	798	631	341	408	162	945	7066
2032	1394	2466	808	641	343	411	163	957	7183
2033	1419	2518	818	651	346	414	164	968	7299
2034	1445	2572	829	661	349	418	164	980	7419
2035	1472	2626	839	672	351	421	165	992	7539

Year	North Isthmus	Auckland	Waikato	Bay of Plenty	Hawkes Bay	Central	Taranaki	Wellington	North Island Total
2036	1499	2682	850	682	354	424	166	1005	7662
2037	1526	2739	861	693	357	428	167	1017	7787
2038	1554	2796	872	703	359	431	168	1029	7912
2039	1583	2856	883	714	362	434	169	1042	8041
2040	1611	2915	894	725	365	438	169	1054	8170

Table 21 Region total at Island peak (mean)—South Island (MW)

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2009	219	55	775	95	1113	2257
2010	225	58	792	99	1129	2303
2011	232	59	810	103	1140	2344
2012	239	73	831	107	1154	2404
2013	245	74	852	110	1167	2448
2014	250	74	873	113	1176	2486
2015	254	75	892	115	1183	2518
2016	256	76	907	117	1186	2541
2017	258	76	922	118	1187	2561
2018	258	77	935	119	1187	2576
2019	259	77	948	119	1187	2590
2020	260	78	961	120	1187	2606
2021	261	78	974	121	1187	2621
2022	262	78	988	122	1189	2639
2023	264	79	1002	123	1191	2658
2024	266	79	1017	124	1193	2679
2025	268	79	1032	126	1197	2702
2026	270	80	1047	127	1200	2725
2027	273	80	1062	128	1204	2747
2028	275	80	1078	130	1207	2770
2029	277	81	1094	131	1211	2794
2030	280	81	1109	133	1215	2818
2031	283	82	1127	134	1219	2845
2032	285	82	1143	136	1223	2869
2033	288	82	1159	138	1227	2894
2034	291	83	1175	139	1231	2919
2035	293	83	1192	141	1235	2944

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	South Island Total
2036	296	83	1208	142	1239	2970
2037	299	84	1225	144	1243	2995
2038	301	84	1242	146	1248	3021
2039	304	85	1259	148	1252	3047
2040	307	85	1277	149	1256	3073

Appendix 2 Build schedules for the five scenarios

Table 22 2010 Sustainable path (mds1) build schedule

Year	Plant description	Technology description	MW
2010	Stratford peaker	Peaker, fast start gas-fired peaker	200
2011	Manapouri MTAD	Hydro, peaking	90
	Te Rere Hau 4	Wind	15
	Te Uku	Wind	64
2012	Diesel fired OCGT 12	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 15	Peaker, diesel-fired OCGT	100
	South Island peak hydro 2	Hydro, peaking	85
2013	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	160
	Ngatamariki	Geothermal	80
	Wairau	Hydro, run of river	73
	Central Wind	Wind	120
2014	Gas fired OCGT 9	Peaker, fast start gas-fired peaker	160
	Arnold	Hydro, run of river	46
2015	Kaiwera Downs	Wind	240
	Demand side response 1 NI	Price-responsive load curtailment	50
	Demand side response 2 NI	Price-responsive load curtailment	36
2016	Te Mihi stage 2	Geothermal	60
	Demand side response 2 NI	Price-responsive load curtailment	11
	New IL 1	Interruptible load	50
2017	Tauhara stage 2	Geothermal	180
2018	Huntly coal unit 2	Coal	-250
	Diesel fired OCGT 3	Peaker, diesel-fired OCGT	100
	Kawerau stage 2	Geothermal	50
	Mokai 4	Geothermal	40

Year	Plant description	Technology description	MW
	Clutha River Queensberry	Hydro, peaking	186
	Otoi Waiau	Hydro, run of river	17
	Demand side response 2 NI	Price-responsive load curtailment	3
	Demand side response 3 NI	Price-responsive load curtailment	50
	Demand side response 4 NI	Price-responsive load curtailment	50
	Demand side response 5 NI	Price-responsive load curtailment	32
2019	Southdown	Combined cycle gas turbine	-122
	Diesel fired OCGT 6	Peaker, diesel-fired OCGT	100
	Hawea Control Gate Retrofit	Hydro, peaking	17
	Kaituna Low Level	Hydro, run of river	38
	Mangawhero to Wanganui Div	Hydro, run of river	60
	Tarawera at Lake Outlet	Hydro, run of river	14
	Toaroha	Hydro, run of river	25
	Titiokura	Wind	13
	Demand side response 5 NI	Price-responsive load curtailment	18
	Demand side response 6 NI	Price-responsive load curtailment	50
2020	Huntly coal unit 3	Coal	-250
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	100
	Ngawha	Geothermal	-25
	Rotokawa 3	Geothermal	50
	Generic geo 2	Geothermal	110
	Biomass Cogen, Kawerau	Cogeneration, biomass-fired	31
	Mohaka	Hydro, run of river	44
	Waitangi Falls Ruakiteri	Hydro, run of river	16
	Whakapapanui Papamanuka	Hydro, run of river	16
	Whangaehu	Hydro, run of river	20
	Titiokura	Wind	35
	Mokairau	Wind	16
	Tenergy NZ Wind Farm	Wind	10

Year	Plant description	Technology description	MW
	Belmont Hills	Wind	12
	Demand side response 7 NI	Price-responsive load curtailment	50
2021	Clarence to Waiau Diversions	Hydro, run of river	70
	Mohikinui	Hydro, run of river	26
	Mill Creek	Wind	9
	Long Gully	Wind	13
	Red Hill	Wind	20
	Belmont Hills	Wind	68
	Demand side response 8 NI	Price-responsive load curtailment	50
	New IL 2	Interruptible load	50
2022	Huntly coal unit 1	Coal	-250
	Marsden Point Refinery	Cogeneration, gas-fired	85
	Diesel fired OCGT 21	Peaker, diesel-fired OCGT	100
	Gas fired OCGT 5	Peaker, fast start gas-fired peaker	100
	Mohikinui	Hydro, run of river	59
	Mill Creek	Wind	62
	Hauauru ma raki	Wind	176
	Generic wind Waikato 2	Wind	200
	Generic wind Central	Wind	100
	Demand side response 9 NI	Price-responsive load curtailment	36
2023	Taranaki CC	Combined cycle gas turbine	-380
	Diesel fired OCGT 9	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 18	Peaker, diesel-fired OCGT	100
	Reciprocating engine 2	Reciprocating engine diesel	27
	Kaituna High Level	Hydro, run of river	35
	Pohangina	Hydro, run of river	10
	Rangitaiki at Mangamako	Hydro, run of river	13
	Tarawera at Te Matae Road	Hydro, run of river	10
	Wairua Falls, Wairua River	Hydro, run of river	11

Year	Plant description	Technology description	MW
	Te Pohue	Wind	225
	Te Rere Hau 5	Wind	12
	Hauauru ma raki	Wind	364
	Wainui Hills	Wind	30
	Demand side response 9 NI	Price-responsive load curtailment	14
	Demand side response 10 NI	Price-responsive load curtailment	50
2024	Reciprocating engine 2	Reciprocating engine diesel	13
	Reciprocating engine 4	Reciprocating engine diesel	15
	Biomass Cogen, Central	Cogeneration, biomass-fired	63
	Waihaha R West Taupo	Hydro, run of river	10
	Awhitu	Wind	18
	Demand side response 11 NI	Price-responsive load curtailment	50
2025	Otahuhu B	Combined cycle gas turbine	-380
	Reciprocating engine 1	Reciprocating engine diesel	12
	Reciprocating engine 4	Reciprocating engine diesel	25
	Generic geo 1	Geothermal	75
	Generic geo 3	Geothermal	110
	Clutha River Tuapeka	Hydro, peaking	340
	Waikato upgrade	Hydro, peaking	150
	Rototuna Forest	Wind	149
	Generic wave 1	Wave	38
	Demand side response 12 NI	Price-responsive load curtailment	50
	Demand side response 13 NI	Price-responsive load curtailment	50
2026	Diesel fired OCGT 7	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 16	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 19	Peaker, diesel-fired OCGT	40
	Rototuna Forest	Wind	101
	Generic solar 4	Solar	50
2027	Diesel fired OCGT 1	Peaker, diesel-fired OCGT	40

Year	Plant description	Technology description	MW
	Diesel fired OCGT 10	Peaker, diesel-fired OCGT	40
	Puketiro	Wind	120
	Generic wind Taranaki	Wind	8
	Generic wave 2	Wave	38
2028	Diesel fired OCGT 4	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 13	Peaker, diesel-fired OCGT	40
	Biomass Cogen, Whirinaki	Cogeneration, biomass-fired	63
	Wairehu Canal	Hydro, run of river	11
	Tiwai Peninsula	Wind	7
2029	Whirinaki	Peaker, diesel-fired OCGT	-155
	Diesel fired OCGT 2	Peaker, diesel-fired OCGT	50
	Diesel fired OCGT 5	Peaker, diesel-fired OCGT	50
	Diesel fired OCGT 11	Peaker, diesel-fired OCGT	50
	Diesel fired OCGT 14	Peaker, diesel-fired OCGT	50
	Gas fired OCGT 7	Peaker, fast start gas-fired peaker	50
	Generic wind Taranaki	Wind	92
	Generic wave 3	Wave	38
2030	Southdown E105	Open cycle gas turbine - gas	-45
	Glenbrook upgrade	Cogeneration, other	80
	Generic pumped hydro	Hydro, pumped storage	300
	North Bank Tunnel	Hydro, peaking	280
2031	Clutha River Luggate	Hydro, peaking	100
2032	Biomass Cogen, Kinleith	Cogeneration, biomass-fired	31
	Tiwai Peninsula	Wind	63
	Vehicle to Grid at peak time 1	Price-responsive load curtailment	47
2033	IGCC coal plant with CCS	Coal, IGCC with CCS	400
	Huntly unit 5 (e3p)	Combined cycle gas turbine	-385
	Vehicle to Grid at peak time 1	Price-responsive load curtailment	53
	Vehicle to Grid at peak time 2	Price-responsive load curtailment	54

Year	Plant description	Technology description	MW
2034	Taipo	Hydro, run of river	33
	Tiwai Peninsula	Wind	10
	Vehicle to Grid at peak time 2	Price-responsive load curtailment	126
2035	IGCC coal plant with CCS 2	Coal, IGCC with CCS	400
	Generic pumped hydro 2	Hydro, pumped storage	300
2036	Biomass Cogen, Ashley	Cogeneration, biomass-fired	21
	Generic solar 6	Solar	50
2037	Butler River	Hydro, run of river	23
	Mahinerangi	Wind	87
2038	Arawata River	Hydro, run of river	40
	Mahinerangi	Wind	113
2039	Arawata River	Hydro, run of river	22
	Upper Grey	Hydro, run of river	35
	Mt Cass	Wind	34
2040	Biomass Cogen, Nelson	Cogeneration, biomass-fired	21
	Aorere River at Shakespeare	Hydro, run of river	52
	Arahura	Hydro, run of river	18
	Mt Cass	Wind	16
	Demand side response 14 NI	Price-responsive load curtailment	50
	Demand side response 15 NI	Price-responsive load curtailment	38
	Vehicle to Grid at peak time 2	Price-responsive load curtailment	20

Table 23 2010 SI wind (mds2) build schedule

2010	Stratford peaker	Peaker, fast start gas-fired peaker	200
2011	Manapouri MTAD	Hydro, peaking	90
	Te Rere Hau 4	Wind	15
	Te Uku	Wind	64
2012	Diesel fired OCGT 1	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 12	Peaker, diesel-fired OCGT	100
	South Island peak hydro 2	Hydro, peaking	85
	Te Pohue	Wind	24
2013	Gas fired OCGT 3	Peaker, fast start gas-fired peaker	160
	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	160
	Ngatamariki	Geothermal	80
	Hawea Control Gate Retrofit	Hydro, peaking	17
	Titiokura	Wind	48
	Project Hayes stage 1	Wind	150
2014	Wairau	Hydro, run of river	73
	Mahinerangi	Wind	200
	Demand side response 1 NI	Price-responsive load curtailment	25
2015	Gas fired OCGT 9	Peaker, fast start gas-fired peaker	160
	Project Hayes stage 2	Wind	160
	Kaiwera Downs	Wind	240
2016	Project Hayes stage 3	Wind	160
	Demand side response 1 NI	Price-responsive load curtailment	25
	Demand side response 2 NI	Price-responsive load curtailment	16
	New IL 1	Interruptible load	50
2017	Te Mihi stage 2	Geothermal	60
	Demand side response 2 NI	Price-responsive load curtailment	34
	Demand side response 3 NI	Price-responsive load curtailment	36

2018	Southdown	Combined cycle gas turbine	-122
	Reciprocating engine 2	Reciprocating engine diesel	13
	Tauhara stage 2	Geothermal	180
	Arnold	Hydro, run of river	46
	Demand side response 3 NI	Price-responsive load curtailment	14
	Demand side response 4 NI	Price-responsive load curtailment	50
2019	Gas fired OCGT 8	Peaker, fast start gas-fired peaker	100
	Mangawhero to Wanganui Div	Hydro, run of river	44
2020	Huntly coal unit 2	Coal	-250
	Otahuhu B	Combined cycle gas turbine	-380
	Diesel fired OCGT 3	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 6	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 15	Peaker, diesel-fired OCGT	100
	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	100
	Gas fired OCGT 11	Peaker, fast start gas-fired peaker	100
	Rotokawa 3	Geothermal	50
	Generic geo 2	Geothermal	110
	Mangawhero to Wanganui Div	Hydro, run of river	16
	Mohaka	Hydro, run of river	44
	Whakapapanui Papamanuka	Hydro, run of river	16
	Mokairau	Wind	16
	Tenergy NZ Wind Farm	Wind	10
	Puketiro	Wind	74
	Generic wind Waikato 2	Wind	164
2021	Gas fired OCGT 5	Peaker, fast start gas-fired peaker	100
	Biomass Cogen, Kawerau	Cogeneration, biomass-fired	31
	Puketiro	Wind	41
2022	Huntly coal unit 1	Coal	-250
	Diesel fired OCGT 9	Peaker, diesel-fired OCGT	100

	Diesel fired OCGT 18	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 21	Peaker, diesel-fired OCGT	100
	North Bank Tunnel	Hydro, peaking	280
	Whangaehu	Hydro, run of river	20
	Pouto	Wind	90
	Puketiro	Wind	4
	Belmont Hills	Wind	80
	Generic wind Waikato 2	Wind	36
	Generic wind Central	Wind	100
2023	Reciprocating engine 2	Reciprocating engine diesel	2
	Central Wind	Wind	120
	Pouto	Wind	210
	Rototuna Forest	Wind	10
	New IL 2	Interruptible load	50
2024	Diesel fired OCGT 16	Peaker, diesel-fired OCGT	40
	Reciprocating engine 2	Reciprocating engine diesel	3
	Biomass Cogen, Central	Cogeneration, biomass-fired	63
	Rototuna Forest	Wind	221
2025	Waikato upgrade	Hydro, peaking	150
2026	Rototuna Forest	Wind	19
	Red Hill	Wind	20
	Demand side response 12 NI	Price-responsive load curtailment	50
	Demand side response 13 NI	Price-responsive load curtailment	35
2027	Diesel fired OCGT 4	Peaker, diesel-fired OCGT	40
	Te Pohue	Wind	201
	Turitea	Wind	113
	Demand side response 13 NI	Price-responsive load curtailment	15
2028	Diesel fired OCGT 7	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 19	Peaker, diesel-fired OCGT	40

	Biomass Cogen, Whirinaki	Cogeneration, biomass-fired	63
	Turitea	Wind	35
2029	Marsden Point Refinery	Cogeneration, gas-fired	85
	Whirinaki	Peaker, diesel-fired OCGT	-155
	Diesel fired OCGT 10	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 13	Peaker, diesel-fired OCGT	40
	Gas fired OCGT 7	Peaker, fast start gas-fired peaker	50
	Gas fired OCGT 10	Peaker, fast start gas-fired peaker	50
	Kaituna High Level	Hydro, run of river	35
	Turitea	Wind	116
2030	Diesel fired OCGT 11	Peaker, diesel-fired OCGT	50
	Reciprocating engine 2	Reciprocating engine diesel	4
	Glenbrook upgrade	Cogeneration, other	80
	Turitea	Wind	36
	Generic wind Waikato	Wind	75
2031	Diesel fired OCGT 2	Peaker, diesel-fired OCGT	50
	Diesel fired OCGT 20	Peaker, diesel-fired OCGT	50
	Reciprocating engine 2	Reciprocating engine diesel	17
	Clutha River Beaumont	Hydro, peaking	190
	Pohangina	Hydro, run of river	10
	Mill Creek	Wind	10
	Long Gully	Wind	13
	Generic wind Waikato	Wind	25
2032	Diesel fired OCGT 8	Peaker, diesel-fired OCGT	50
	Diesel fired OCGT 14	Peaker, diesel-fired OCGT	50
	Biomass Cogen, Kinleith	Cogeneration, biomass-fired	31
	Rangitaiki at Mangamako	Hydro, run of river	13
	Mill Creek	Wind	3
2033	Diesel fired OCGT 5	Peaker, diesel-fired OCGT	50

	Diesel fired OCGT 17	Peaker, diesel-fired OCGT	50
	Reciprocating engine 2	Reciprocating engine diesel	2
	Reciprocating engine 4	Reciprocating engine diesel	8
	Taumatatotara	Wind	32
	Mill Creek	Wind	58
2034	Gas fired OCGT 1	Peaker, fast start gas-fired peaker	50
	Reciprocating engine 1	Reciprocating engine diesel	29
	Reciprocating engine 4	Reciprocating engine diesel	32
	Clutha River Queensberry	Hydro, peaking	186
	Taumatatotara	Wind	12
	Hauauru ma raki	Wind	87
2035	Gas fired OCGT 4	Peaker, fast start gas-fired peaker	50
	Reciprocating engine 1	Reciprocating engine diesel	11
	Reciprocating engine 3	Reciprocating engine diesel	40
	Hauauru ma raki	Wind	153
2036	Generic pumped hydro	Hydro, pumped storage	300
2037	IGCC coal plant with CCS	Coal, IGCC with CCS	400
2038	Toaroha	Hydro, run of river	25
2039	Te Rere Hau 5	Wind	12
	Hauauru ma raki	Wind	64
2040	Clutha River Luggate	Hydro, peaking	100
	Hauauru ma raki	Wind	57

Table 24 2010 Medium renewables (mds3) build schedule

2010	Stratford peaker	Peaker, fast start gas-fired peaker	200
2011	Manapouri MTAD	Hydro, peaking	90
	Te Rere Hau 4	Wind	15
	Te Uku	Wind	64
2012	Diesel fired OCGT 7	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 12	Peaker, diesel-fired OCGT	100
	South Island peak hydro 2	Hydro, peaking	85
	Titiokura	Wind	48
2013	Gas fired OCGT 12	Peaker, fast start gas-fired peaker	160
	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	160
	Ngatamariki	Geothermal	80
2014	Wairau	Hydro, run of river	73
	Central Wind	Wind	120
	Demand side response 1 NI	Price-responsive load curtailment	6
2015	Reciprocating engine 1	Reciprocating engine diesel	36
	Mohikinui	Hydro, run of river	85
	Demand side response 1 NI	Price-responsive load curtailment	44
	Demand side response 2 NI	Price-responsive load curtailment	50
2016	Te Mihi stage 2	Geothermal	60
	Mahinerangi	Wind	200
	Demand side response 3 NI	Price-responsive load curtailment	11
	New IL 1	Interruptible load	50
2017	Mokai 4	Geothermal	40
	Demand side response 3 NI	Price-responsive load curtailment	39
	Demand side response 4 NI	Price-responsive load curtailment	49
2018	Tauhara stage 2	Geothermal	180
2019	Southdown	Combined cycle gas turbine	-122

	Gas fired OCGT 9	Peaker, fast start gas-fired peaker	160
	Kawerau stage 2	Geothermal	50
	Awhitu	Wind	18
2020	Rotokawa 3	Geothermal	50
	Generic geo 2	Geothermal	110
2021	Taranaki CC	Combined cycle gas turbine	-380
	Gas fired OCGT 3	Peaker, fast start gas-fired peaker	160
	Gas fired OCGT 6	Peaker, fast start gas-fired peaker	160
	Reciprocating engine 2	Reciprocating engine diesel	40
	Reciprocating engine 4	Reciprocating engine diesel	30
	Mangawhero to Wanganui Div	Hydro, run of river	60
	Demand side response 4 NI	Price-responsive load curtailment	1
	New IL 2	Interruptible load	50
2022	Huntly coal unit 1	Coal	-250
	Marsden Coal	Coal	320
	Diesel fired OCGT 18	Peaker, diesel-fired OCGT	100
2023	Gas fired OCGT 8	Peaker, fast start gas-fired peaker	100
2024	Diesel fired OCGT 3	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 6	Peaker, diesel-fired OCGT	100
2025	Huntly coal unit 4	Coal	-250
	Diesel fired OCGT 15	Peaker, diesel-fired OCGT	100
	Generic geo 1	Geothermal	75
	Generic geo 3	Geothermal	110
	Kaiwera Downs	Wind	240
	Demand side response 12 NI	Price-responsive load curtailment	17
2026	Diesel fired OCGT 9	Peaker, diesel-fired OCGT	100
	Demand side response 12 NI	Price-responsive load curtailment	25
2027	Diesel fired OCGT 21	Peaker, diesel-fired OCGT	100
	Demand side response 12 NI	Price-responsive load curtailment	8

	Demand side response 13 NI	Price-responsive load curtailment	13
2028	Otahuhu C	Combined cycle gas turbine	407
2029	Whirinaki	Peaker, diesel-fired OCGT	-155
	Demand side response 13 NI	Price-responsive load curtailment	2
2030	Southdown E105	Open cycle gas turbine - gas	-45
	Generic pumped hydro	Hydro, pumped storage	300
	Hauauru ma raki	Wind	540
2032	Demand side response 13 NI	Price-responsive load curtailment	5
2033	Rodney CCGT stage 1	Combined cycle gas turbine	240
2034	Glenbrook upgrade	Cogeneration, other	80
2035	Gas fired OCGT 11	Peaker, fast start gas-fired peaker	100
	North Bank Tunnel	Hydro, peaking	280
	Demand side response 13 NI	Price-responsive load curtailment	3
2036	Gas fired OCGT 2	Peaker, fast start gas-fired peaker	100
	Reciprocating engine 4	Reciprocating engine diesel	7
	Demand side response 13 NI	Price-responsive load curtailment	27
2037	Diesel fired OCGT 1	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 13	Peaker, diesel-fired OCGT	40
	Gas fired OCGT 5	Peaker, fast start gas-fired peaker	100
2038	Diesel fired OCGT 4	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 16	Peaker, diesel-fired OCGT	40
	Diesel fired OCGT 19	Peaker, diesel-fired OCGT	40
2039	Marsden Point Refinery	Cogeneration, gas-fired	85
	Diesel fired OCGT 10	Peaker, diesel-fired OCGT	40
	Reciprocating engine 3	Reciprocating engine diesel	22
	Reciprocating engine 4	Reciprocating engine diesel	3
2040	Waikato upgrade	Hydro, peaking	150

Table 25 2010 Coal (mds4) build schedule

2010	Stratford peaker	Peaker, fast start gas-fired peaker	200
2011	Te Rere Hau 4	Wind	15
	Te Uku	Wind	64
2012	Diesel fired OCGT 3	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 9	Peaker, diesel-fired OCGT	100
	South Island peak hydro 2	Hydro, peaking	85
2013	Gas fired OCGT 12	Peaker, fast start gas-fired peaker	160
	Wairakei	Geothermal	-163
	Te Mihi	Geothermal	160
	Hawea Control Gate Retrofit	Hydro, peaking	17
2014	Te Mihi stage 2	Geothermal	60
	Demand side response 1 NI	Price-responsive load curtailment	1
2015	Reciprocating engine 1	Reciprocating engine diesel	15
	Mill Creek	Wind	71
	Demand side response 1 NI	Price-responsive load curtailment	49
	Demand side response 2 NI	Price-responsive load curtailment	50
2016	Mokai 4	Geothermal	40
	Taumatatotara	Wind	44
	Demand side response 3 NI	Price-responsive load curtailment	20
	New IL 1	Interruptible load	50
2017	Tauhara stage 2	Geothermal	180
2018	Reciprocating engine 2	Reciprocating engine diesel	5
	Demand side response 3 NI	Price-responsive load curtailment	30
	Demand side response 4 NI	Price-responsive load curtailment	50
2019	Reciprocating engine 2	Reciprocating engine diesel	5
	Kawerau stage 2	Geothermal	50
	Ngatamariki	Geothermal	80
2020	Marsden Coal	Coal	320

	Taranaki CC	Combined cycle gas turbine	-380
	Gas fired OCGT 9	Peaker, fast start gas-fired peaker	160
	Rotokawa 3	Geothermal	50
	Generic geo 2	Geothermal	110
	North Bank Tunnel	Hydro, peaking	280
2021	Reciprocating engine 2	Reciprocating engine diesel	30
	Reciprocating engine 4	Reciprocating engine diesel	12
	New IL 2	Interruptible load	50
2022	Huntly coal unit 1	Coal	-250
	Generic coal 1 Glenbrook	Coal	400
2023	Gas fired OCGT 6	Peaker, fast start gas-fired peaker	160
2024	Gas fired OCGT 3	Peaker, fast start gas-fired peaker	160
2025	Generic lignite 1 Southland	Lignite	400
	Demand side response 12 NI	Price-responsive load curtailment	41
2026	Generic geo 1	Geothermal	75
	Generic geo 3	Geothermal	110
2027	Diesel fired OCGT 12	Peaker, diesel-fired OCGT	100
	Gas fired OCGT 8	Peaker, fast start gas-fired peaker	100
2029	Generic gas 1 Auckland	Combined cycle gas turbine	410
	Huntly unit 6 (P40)	Open cycle gas turbine - gas	-50
	Whirinaki	Peaker, diesel-fired OCGT	-155
2030	Generic coal 5 Huntly stage 1	Coal	400
	Southdown E105	Open cycle gas turbine - gas	-45
2032	Glenbrook upgrade	Cogeneration, other	80
2033	Huntly unit 5 (e3p)	Combined cycle gas turbine	-385
	Otahuhu C	Combined cycle gas turbine	407
	Reciprocating engine 1	Reciprocating engine diesel	10
	Reciprocating engine 4	Reciprocating engine diesel	28
	Demand side response 12 NI	Price-responsive load curtailment	9

	Demand side response 13 NI	Price-responsive load curtailment	50
2034	New Plymouth CC 1	Combined cycle gas turbine	380
2035	Wairau	Hydro, run of river	26
2036	Reciprocating engine 1	Reciprocating engine diesel	6
	Wairau	Hydro, run of river	47
	Puketiro	Wind	69
2037	Rodney CCGT stage 1	Combined cycle gas turbine	240
2038	Central Wind	Wind	95
	Mokairau	Wind	16
	Tenergy NZ Wind Farm	Wind	10
	Puketiro	Wind	51
2039	Taranaki CC 3	Combined cycle gas turbine	380
2040	Clutha River Luggate	Hydro, peaking	100
	Central Wind	Wind	25
	Rototuna Forest	Wind	52

Table 26 2010 High gas discovery (mds5) build schedule

2010	Stratford peaker	Peaker, fast start gas-fired peaker	200
2011	Te Rere Hau 4	Wind	15
	Te Uku	Wind	64
2012	Diesel fired OCGT 3	Peaker, diesel-fired OCGT	100
	Diesel fired OCGT 6	Peaker, diesel-fired OCGT	100
	South Island peak hydro 2	Hydro, peaking	85
2013	Ngatamariki	Geothermal	80
	Central Wind	Wind	120
2014	Gas fired OCGT 12	Peaker, fast start gas-fired peaker	160
2015	Taranaki Cogen	Cogeneration, gas-fired	50
	Demand side response 1 NI	Price-responsive load curtailment	50
	Demand side response 2 NI	Price-responsive load curtailment	4
2016	Demand side response 2 NI	Price-responsive load curtailment	46
	Demand side response 3 NI	Price-responsive load curtailment	18
	New IL 1	Interruptible load	50
2017	Huntly coal unit 1	Coal	-250
	Otahuhu C	Combined cycle gas turbine	407
	Te Rere Hau 5	Wind	12
	Awhitu	Wind	18
2018	Mangawhero to Wanganui Div	Hydro, run of river	15
	Wairau	Hydro, run of river	2
	Demand side response 3 NI	Price-responsive load curtailment	32
	Demand side response 4 NI	Price-responsive load curtailment	50
2019	Generic gas 1 Auckland	Combined cycle gas turbine	410
2021	New IL 2	Interruptible load	10
2022	Tauhara stage 2	Geothermal	180
2023	Huntly coal unit 2	Coal	-250
	Gas fired OCGT 9	Peaker, fast start gas-fired peaker	160

	Reciprocating engine 2	Reciprocating engine diesel	21
	Rotokawa 3	Geothermal	50
	Clutha River Queensberry	Hydro, peaking	186
	Mangawhero to Wanganui Div	Hydro, run of river	45
	New IL 2	Interruptible load	40
2024	Taranaki CC	Combined cycle gas turbine	-380
	Generic gas 2 Taranaki	Combined cycle gas turbine	410
	Gas fired OCGT 3	Peaker, fast start gas-fired peaker	160
	Wairau	Hydro, run of river	13
2025	Huntly coal unit 4	Coal	-250
	Diesel fired OCGT 12	Peaker, diesel-fired OCGT	100
	Reciprocating engine 2	Reciprocating engine diesel	9
	Generic geo 3	Geothermal	110
	Wairau	Hydro, run of river	58
	Demand side response 12 NI	Price-responsive load curtailment	50
	Demand side response 13 NI	Price-responsive load curtailment	50
2026	Huntly unit 6 (P40)	Open cycle gas turbine - gas	-50
	Gas fired OCGT 6	Peaker, fast start gas-fired peaker	160
	Reciprocating engine 2	Reciprocating engine diesel	10
	Reciprocating engine 4	Reciprocating engine diesel	6
2027	Taranaki CC 3	Combined cycle gas turbine	380
	Southdown E105	Open cycle gas turbine - gas	-45
2029	New Plymouth CC 1	Combined cycle gas turbine	380
	Whirinaki	Peaker, diesel-fired OCGT	-155
2030	Glenbrook upgrade	Cogeneration, other	80
2031	Rodney CCGT stage 1	Combined cycle gas turbine	240
2033	Reciprocating engine 1	Reciprocating engine diesel	10
	Reciprocating engine 4	Reciprocating engine diesel	34
	New IL 3	Interruptible load	30

2034	Rodney CCGT stage 2	Combined cycle gas turbine	240
2035	Taranaki CC 2	Combined cycle gas turbine	380
2038	Gas fired OCGT 8	Peaker, fast start gas-fired peaker	100
	Reciprocating engine 1	Reciprocating engine diesel	30
	Reciprocating engine 3	Reciprocating engine diesel	7
	New IL 3	Interruptible load	20
2039	Gas fired OCGT 11	Peaker, fast start gas-fired peaker	100
	North Bank Tunnel	Hydro, peaking	280
2040	Diesel fired OCGT 15	Peaker, diesel-fired OCGT	100
	Reciprocating engine 3	Reciprocating engine diesel	5

Appendix 3 National energy demand projections

Table 27 National energy demand projections (GWh)—March years

Year	Baseline	80 per cent confidence limits		Sectoral breakdown			
		High	Low	Residential	Commercial and industrial[71]	Local line losses	Embedded generation excluded
2009	38,924	39,122	38,734	12,919	26,179	1763	1937
2010	38,725	39,208	38,279	13,011	25,888	1753	1927
2011	39,843	40,550	39,139	13,299	26,716	1811	1983
2012	40,747	41,645	39,841	13,547	27,370	1858	2028
2013	41,809	42,904	40,676	13,815	28,161	1913	2081
2014	42,765	44,057	41,443	14,069	28,861	1963	2128
2015	43,645	45,106	42,109	14,322	29,486	2009	2172
2016	44,487	46,102	42,754	14,556	30,092	2053	2214
2017	45,196	46,979	43,267	14,778	30,577	2090	2249
2018	45,937	47,927	43,805	15,017	31,077	2128	2286
2019	46,630	48,808	44,318	15,237	31,549	2165	2320
2020	47,315	49,673	44,827	15,439	32,030	2200	2355
2021	48,016	50,555	45,298	15,648	32,520	2237	2389
2022	48,718	51,479	45,817	15,869	33,000	2273	2424
2023	49,428	52,353	46,343	16,089	33,489	2310	2460
2024	50,143	53,288	46,820	16,304	33,987	2347	2495
2025	50,880	54,237	47,331	16,532	34,494	2386	2532
2026	51,627	55,156	47,861	16,761	35,011	2425	2569
2027	52,355	56,118	48,430	16,993	35,504	2463	2605
2028	53,054	57,012	48,885	17,189	36,005	2499	2640

71 This includes the Tiwai smelter.

Year	Baseline	80 per cent confidence limits		Sectoral breakdown			
		High	Low	Residential	Commercial and industrial[71]	Local line losses	Embedded generation excluded
2029	53,787	57,965	49,397	17,411	36,516	2537	2677
2030	54,521	58,871	49,881	17,623	37,035	2576	2713
2031	55,257	59,857	50,420	17,829	37,564	2614	2750
2032	55,978	60,802	50,914	18,023	38,089	2651	2786
2033	56,728	61,795	51,418	18,237	38,623	2691	2823
2034	57,471	62,752	51,926	18,435	39,167	2729	2860
2035	58,234	63,792	52,409	18,644	39,719	2769	2898
2036	58,995	64,748	52,896	18,841	40,282	2809	2936
2037	59,766	65,842	53,376	19,036	40,855	2849	2974
2038	60,546	66,880	53,901	19,230	41,439	2889	3013
2039	61,334	68,012	54,398	19,423	42,033	2930	3052
2040	62,131	69,118	54,964	19,614	42,636	2972	3092

Figures in GWh

80 per cent confidence limits: High = 90^{th} percentile, Low = 10^{th} percentile

Total demand = Residential demand + Commercial/Industrial Demand + Local lines losses—Embedded generation

Appendix 4 Transmission regions and Grid Exit Points

North Island regions

North Isthmus
Albany (ALB)
Bream Bay (BRB)
Dargaville (DAR)
Henderson (HEN)
Hepburn Rd (HEP)
Kensington (KEN)
Kaikohe (KOE)
Kaitaia (KTA)
Maungatapere (MPE)
Maungaturoto (MTO)
Silverdale (SVL)
Wellsford WEL)
Wairau Road (WRU)

Bay of Plenty
Aniwhenua (ANI)
Edgecumbe (EDG)
Kaitemako (KMO)[72]
Kawerau (KAW)
Mt Maunganui (MTM)
Owhata (OWH)
Rotorua (ROT)
Tauranga (TGA)
Te Kaha (TKH)
Te Matai (TMI)
Tarukenga (TRK)
Waiotahi (WAI)

Auckland
Bombay (BOB)
Meremere (MER)
Glenbrook (GLN)
Liverpool St (LST)
Mangere (MNG)
Otahuhu (OTA)
Pakuranga (PAK)
Penrose (PEN)
Mt Roskill (ROS)
Takanini (TAK)
Wiri (WIR)

Central
Bunnythorpe (BPE)
Brunswick (BRK)
Dannevirke (DVK)
Linton (LTN)
Mangamaire (MGM)
Mangahao (MHO)
Marton (MTN)
Mataroa (MTR)
National Park (NPK)
Ohakune (OKN)
Ongarue (ONG)
Tokaanu (TKU)
Tangiwai (TNG)
Woodville (WDV)
Wanganui (WGN)
Waipawa (WPW)

Taranaki
Carrington St (CST)
Huirangi (HUI)
Hawera (HWA)
Motunui (MNI)
New Plymouth (NPL)
Opunake (OPK)
TCC (SFD)
Taumarunui (TMN)
Whareroa (WAA)
Waverley (WVY)

Wellington
Central Park (CPK)
Gracefield (GFD)
Greytown (GYT)
Haywards (HAY)
Kaiwharawhara (KWA)
Melling (MLG)
Masterton (MST)
Pauatahanui (PNI)
Paraparaumu (PRM)
Takapu Road (TKR)
Upper Hutt (UHT)
Wilton (WIL)

Waikato
Cambridge (CBG)
Hamilton (HAM)
Hinuera (HIN)
Huntly (HLY)
Hangatiki (HTI)
Kinleith (KIN)
Kopu (KPU)
Lichfield (LFD)
Ohaaki (OKI)
Te Awamutu (TMU)
Te Kowhai (TWH)
Western Road (WES)
Waihou (WHU)
Whakamaru (WKM)
Waikino (WKO)
Wairakei (WRK)

Hawke's Bay
Fernhill (FHL)
Gisborne (GIS)
Redclyffe (RDF)
Tuai (TUI)
Whirinaki (WHI)
Wairoa (WRA)
Whakatu (WTU)

72 This GXP has been recently commissioned. Demand at this GXP has not been separated out from the existing load.

South Island regions

Otago/Southland
Balclutha (BAL)
Brydone (BDE)
Blackpoint (BPT)
Cromwell (CML)
Clyde (CYD)
Edendale (EDN)
Frankton (FKN)
Gore (GOR)
Halfway Bush (HWB)
Invercargill (INV)
North Makarewa (NMA)
Naseby (NSY)
Oamaru (OAM)
Palmerston (PAL)
South Dunedin (SDN)
Studholme (STU)
Tiwai (TWI)
Waitaki (WTK)

West Coast
Arthur's Pass (APS)
Atarau (ATU)
Castle Hill (CLH)
Dobson 33kV (DOB)
Greymouth (GYM)
Hokitika (HKK)
Murchison (MCH)
Orowaiti (ROB)
Otira (OTI)
Reefton (RFT)
Westport (WPT)

Canterbury
Addington (ADD)
Ashburton (ASB)
Ashley (ASY)
Bromley (BRY)
Coleridge (COL)
Culverden (CUL)
Hororata (HOR)
Islington (ISL)
Kaiapoi (KAI)
Kaikoura (KKA)
Middleton (MLN)
Papanui (PAP)
Southbrook (SBK)
Springston (SPN)
Waipara (WPR)

South Canterbury
Albury (ABY)
Timaru (TIM)
Tekapo (TKA)
Temuka (TMK)
Twizel (TWZ)
Bell's Pond (BPD)

Nelson/Marlborough
Blenheim (BLN)
Kikiwa (KIK)
Motueka (MOT)
Motupipi (MPI)
Stoke (STK)

Appendix 5 Regional energy demand projections

Table 28 Regional energy demand projections[73] North Island (GWh)—March years

Year	North Isthmus	Auck-land	Waikato	BOP	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2009	4075	6973	3056	2832	1760	1705	812	3115	24,329
2010	4064	6943	3014	2792	1730	1647	864	3083	24,137
2011	4191	7153	3076	2850	1759	1708	878	3157	24,773
2012	4313	7356	3134	2903	1786	1759	890	3228	25,370
2013	4450	7594	3206	2969	1819	1822	906	3311	26,077
2014	4578	7824	3273	3029	1848	1870	919	3388	26,729
2015	4697	8056	3339	3086	1873	1910	930	3462	27,352
2016	4811	8301	3407	3146	1896	1943	941	3534	27,979
2017	4911	8545	3470	3201	1913	1963	948	3600	28,551
2018	5015	8816	3542	3264	1931	1982	956	3670	29,176
2019	5114	9090	3613	3328	1949	1998	962	3736	29,789
2020	5213	9367	3683	3394	1966	2012	968	3800	30,404
2021	5314	9645	3753	3462	1984	2028	975	3865	31,026
2022	5419	9913	3819	3529	2003	2045	982	3927	31,635
2023	5525	10,174	3883	3594	2022	2063	988	3987	32,237
2024	5634	10,432	3944	3659	2040	2082	995	4046	32,832
2025	5747	10,690	4004	3723	2059	2102	1001	4107	33,434
2026	5861	10,947	4064	3788	2078	2122	1008	4168	34,036
2027	5975	11,198	4121	3848	2096	2142	1014	4226	34,620
2028	6084	11,444	4174	3907	2112	2159	1019	4280	35,181
2029	6200	11,698	4230	3968	2130	2179	1025	4337	35,766

[73] In Table 28 and Table 29, the figures represent the aggregate electricity demand at GXPs.

Year	North Isthmus	Auck-land	Waikato	BOP	Hawkes Bay	Central	Taranaki	Wellington	Total North Island
2030	6315	11,953	4285	4029	2146	2197	1030	4394	36,350
2031	6432	12,212	4340	4091	2163	2216	1035	4450	36,939
2032	6547	12,469	4394	4155	2178	2233	1041	4503	37,519
2033	6667	12,735	4449	4220	2195	2251	1046	4558	38,121
2034	6786	13,002	4504	4285	2211	2268	1051	4611	38,719
2035	6909	13,276	4560	4351	2227	2286	1057	4667	39,333
2036	7031	13,553	4616	4418	2243	2304	1062	4721	39,948
2037	7156	13,836	4672	4485	2258	2321	1067	4775	40,571
2038	7282	14,123	4729	4554	2274	2339	1072	4830	41,203
2039	7409	14,415	4786	4623	2289	2356	1078	4885	41,842
2040	7539	14,712	4844	4694	2305	2373	1083	4940	42,490

Table 29 Regional energy demand projections South Island (GWh)—March years

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	Total South Island
2009	1166	296	4382	639	8112	14,595
2010	1163	417	4370	641	7995	14,588
2011	1200	426	4508	665	8271	15,071
2012	1234	435	4639	688	8381	15,377
2013	1271	445	4787	713	8516	15,732
2014	1304	454	4921	735	8622	16,036
2015	1331	463	5043	755	8702	16,294
2016	1353	471	5154	771	8759	16,508
2017	1365	478	5242	782	8778	16,645
2018	1372	485	5328	790	8786	16,761
2019	1375	491	5401	795	8779	16,841
2020	1377	496	5470	799	8768	16,910
2021	1380	501	5542	804	8764	16,990
2022	1385	505	5617	809	8766	17,083
2023	1393	509	5696	816	8777	17,191
2024	1402	513	5779	824	8793	17,311
2025	1414	517	5867	833	8816	17,447
2026	1427	521	5958	843	8843	17,591
2027	1438	525	6049	853	8870	17,735
2028	1451	529	6134	862	8896	17,872
2029	1464	533	6227	873	8925	18,021
2030	1478	537	6318	883	8954	18,170
2031	1490	540	6411	894	8983	18,318
2032	1503	544	6498	904	9010	18,459
2033	1517	548	6589	915	9039	18,607
2034	1530	552	6678	926	9067	18,752

Year	Nelson/ Marlborough	West Coast	Canterbury	South Canterbury	Otago/ Southland	Total South Island
2035	1543	556	6770	936	9096	18,901
2036	1556	560	6860	947	9124	19,047
2037	1570	564	6951	958	9152	19,195
2038	1583	568	7043	969	9181	19,343
2039	1596	572	7135	980	9209	19,492
2040	1609	576	7228	991	9237	19,642

Appendix 6 Prudent and expected peak forecasts

Table 30 National forecast

Year	Observed peak (MW)	Expected peak (MW)	Prudent peak (MW)
1997	5510	-	-
1998	5338	-	-
1999	5548	-	-
2000	5574	-	-
2001	5766	-	-
2002	5804	-	-
2003	5708	-	-
2004	6065	-	-
2005	6078	-	-
2006	6387	-	-
2007	6455	-	-
2008	6224	-	-
2009	-	6729	6884
2010	-	6870	7055
2011	-	7009	7245
2012	-	7170	7454
2013	-	7326	7712
2014	-	7473	7861
2015	-	7615	8023
2016	-	7734	8196
2017	-	7858	8351
2018	-	7975	8488
2019	-	8091	8600
2020	-	8210	8737
2021	-	8326	8931
2022	-	8446	9075
2023	-	8565	9265
2024	-	8688	9410
2025	-	8813	9557
2026	-	8935	9693
2027	-	9053	9886
2028	-	9177	10,004
2029	-	9300	10,183
2030	-	9425	10,343
2031	-	9560	10,471
2032	-	9690	10,713
2033	-	9820	10,823
2034	-	9953	11,029
2035	-	10,087	11,214
2036	-	10,223	11,304
2037	-	10,361	11,604
2038	-	10,500	11,732
2039	-	10,642	11,948
2040	-	10,784	12,102

Table 31 Island forecast—North Island and South Island

Year	NI Observed peak (MW)	NI Expected Peak (MW)	NI Prudent peak (MW)	SI Observed peak (MW)	SI Expected peak (MW)	SI Prudent peak (MW)
1997	3717	-	-	1822	-	-
1998	3531	-	-	1826	-	-
1999	3669	-	-	1888	-	-
2000	3672	-	-	1902	-	-
2001	3874	-	-	1967	-	-
2002	3840	-	-	1994	-	-
2003	3827	-	-	1941	-	-
2004	4086	-	-	2026	-	-
2005	4040	-	-	2071	-	-
2006	4273	-	-	2121	-	-
2007	4318	-	-	2173	-	-
2008	4189	-	-	2113	-	-
2009	-	4502	4638	-	2257	2286
2010	-	4602	4747	-	2299	2351
2011	-	4704	4881	-	2338	2406
2012	-	4823	5034	-	2382	2474
2013	-	4940	5205	-	2424	2548
2014	-	5055	5328	-	2460	2573
2015	-	5170	5474	-	2490	2617
2016	-	5273	5587	-	2511	2644
2017	-	5386	5731	-	2529	2665
2018	-	5495	5850	-	2543	2684
2019	-	5605	6015	-	2555	2702
2020	-	5716	6155	-	2569	2719
2021	-	5826	6266	-	2583	2732
2022	-	5935	6418	-	2599	2743

Year	NI Observed peak (MW)	NI Expected Peak (MW)	NI Prudent peak (MW)	SI Observed peak (MW)	SI Expected peak (MW)	SI Prudent peak (MW)
2023	-	6042	6511	-	2617	2789
2024	-	6152	6679	-	2636	2809
2025	-	6261	6840	-	2656	2823
2026	-	6368	6952	-	2677	2863
2027	-	6471	7088	-	2697	2888
2028	-	6578	7189	-	2719	2914
2029	-	6685	7337	-	2741	2947
2030	-	6793	7505	-	2762	2964
2031	-	6909	7647	-	2787	3001
2032	-	7022	7808	-	2810	3034
2033	-	7134	7959	-	2832	3074
2034	-	7250	8068	-	2855	3106
2035	-	7366	8216	-	2878	3153
2036	-	7485	8357	-	2901	3161
2037	-	7605	8577	-	2925	3211
2038	-	7726	8704	-	2948	3254
2039	-	7850	8859	-	2972	3284
2040	-	7975	9007	-	2996	3295

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Appendix 7 List of plants forced in, for the five generation scenarios

Table 32 List of plants forced in, for the five generation scenarios

Plant name	2010 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery
Marsden Coal	-	-	2022	-	-
Generic coal 1 Glenbrook	-	-	-	2022	-
Generic coal 5 Huntly stage 1	-	-	-	2030	-
Generic lignite 1 Southland	-	-	-	2025	-
IGCC coal plant with CCS 2	2035	-	-	-	-
Otahuhu C	-	-	-	-	2017
Rodney CCGT stage 1	-	-	2033	-	-
Taranaki CC 2	-	-	-	-	2035
Taranaki CC 3	-	-	-	2039	2027
Stratford peaker	2010	2010	2010	2010	2010
Te Mihi	2013	2013	2013	2013	-
Ngatamariki	2013	2013	2013	-	2013
Taranaki Cogen	-	-	-	-	2015
Generic pumped hydro	2030	-	2030	-	-
Generic pumped hydro 2	2035	-	-	-	-
Hawea Control Gate Retrofit	-	2013	-	2013	-
North Bank Tunnel	-	2022	2035	-	-
Waikato upgrade	2025	2025	-	-	-
South Island peak hydro	2012	2012	2012	2012	2012
Manapouri MTAD	2011	2011	2011	-	-
Arnold	2014	2018	-	-	-
Mohikinui	-	-	2013	-	-
Wairau	2013	2014	2014	-	-

Plant name	2010 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery
Generic wave 1	2025	-	-	-	-
Generic wave 2	2027	-	-	-	-
Generic wave 3	2029	-	-	-	-
Generic solar 4	2026	-	-	-	-
Generic solar 6	2036	-	-	-	-
Titiokura	-	2013	2012	-	-
Project Hayes stage 1	-	2013	-	-	-
Project Hayes stage 2	-	2015	-	-	-
Project Hayes stage 3	-	2016	-	-	-
Te Rere Hau 4	2011	2011	2011	2011	2011
Te Rere Hau 5	-	-	-	-	2017
Taumatatotara	-	-	-	2016	-
Te Uku	2011	2011	2011	2011	2011
Awhitu	-	-	2019	-	2017
Mahinerangi	-	2014	2016	-	-
Kaiwera Downs	2015	2015	2025	-	-
Hauauru ma raki	-	-	2030	-	-
Mill Creek	-	-	-	2015	-
Central Wind	2013	-	2014	-	2013

Appendix 8 Gas availability

Table 33 Gas availability in PJ for electricity generation

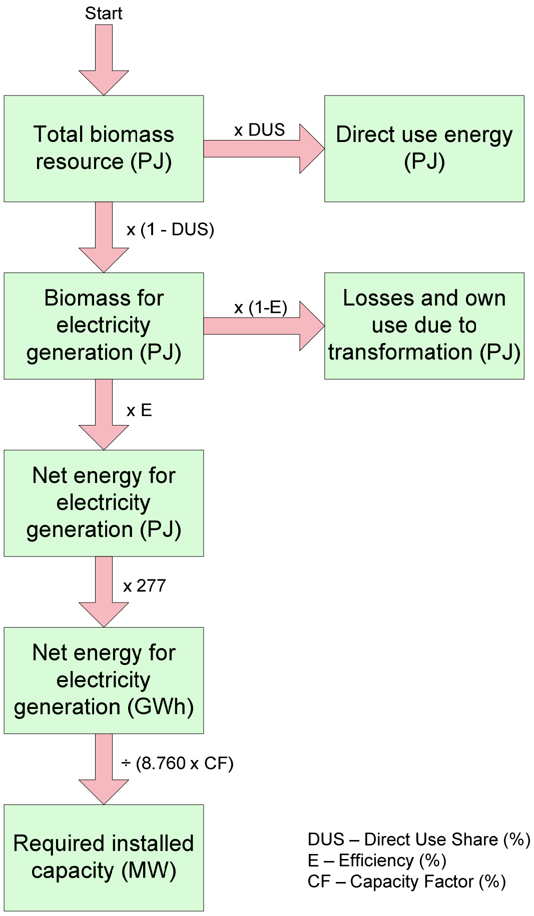
Year	2010 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery
2010	106	106	106	106	106
2011	104	104	104	104	104
2012	101	101	101	101	101
2013	103	103	103	103	104
2014	99	99	99	99	104
2015	75	75	79	79	87
2016	67	67	74	74	84
2017	64	64	75	75	87
2018	63	63	75	75	92
2019	47	47	62	62	94
2020	unlimited	unlimited	49	49	99
2021	unlimited	unlimited	43	43	102
2022	unlimited	unlimited	42	42	101
2023	unlimited	unlimited	48	48	98
2024	unlimited	unlimited	48	48	95
2025	unlimited	unlimited	49	49	99
2026	unlimited	unlimited	51	51	104
2027	unlimited	unlimited	53	53	111
2028	unlimited	unlimited	51	51	114
2029	unlimited	unlimited	49	49	117
2030	unlimited	unlimited	53	53	125
2031	unlimited	unlimited	56	56	132
2032	unlimited	unlimited	59	59	138
2033	unlimited	unlimited	62	62	144
2034	unlimited	unlimited	66	66	149
2035	unlimited	unlimited	69	69	154

Year	2010 Sustainable path	2010 SI wind	2010 Medium renewables	2010 Coal	2010 High gas discovery
2036	unlimited	unlimited	72	72	158
2037	unlimited	unlimited	75	75	162
2038	unlimited	unlimited	78	78	165
2039	unlimited	unlimited	80	80	169
2040	unlimited	unlimited	82	82	171

Appendix 9 Biomass installed capacity assumed in the scenarios

The flow chart below shows how the maximum installed capacity has been derived from the estimated total biomass resource. As shown on the chart a small proportion of the initial total biomass resource ends up as net energy for electricity generation.

The four main parameters that influence the maximum installed capacity that could be built, if economic, are the total biomass resource, the share that goes to direct use (DUS), the efficiency of the plant (E), and the capacity factor (CF).



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Appendix 10 HVDC charge assumptions

Table 34 HVDC charge assumptions in $/kW

Year	HVDC charge ($/kW)
2010	23
2011	22
2012	47
2013	45
2014	45
2015	43
2016	42
2017	40
2018	39
2019	37
2020	35
2021	34
2022	33
2023	31
2024	29
2025	28
2026	27
2027	26
2028	26
2029	25
2030	24
2031	24
2032	23
2033	22
2034	22
2035	38
2036	37
2037	36
2038	35
2039	33
2040	32

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Appendix 11 Installed capacity (MW) by fuel and year, for each market development scenario

Figure 51 Capacity by fuel by year, for the 2010 Sustainable path scenario

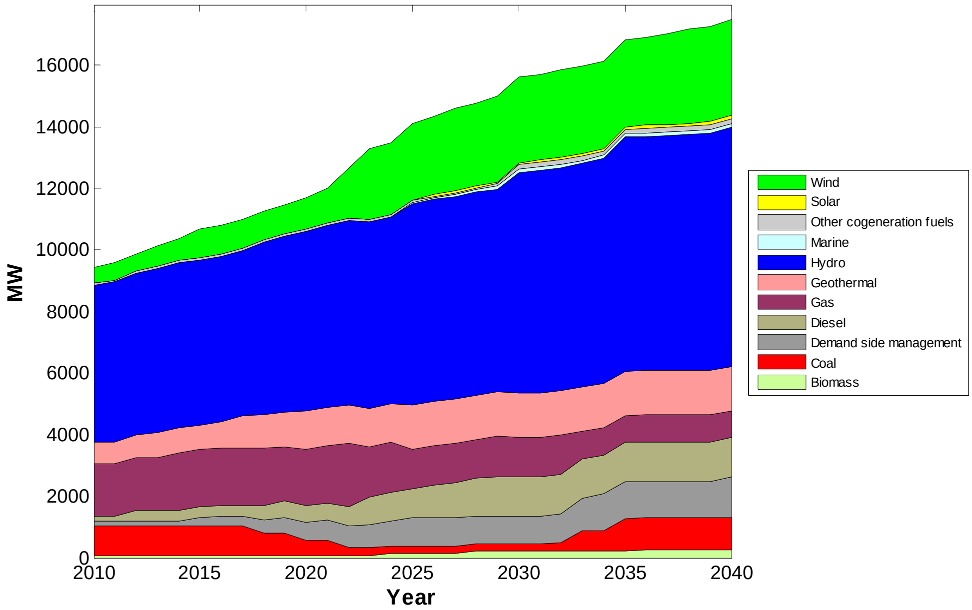


Figure 52 Capacity by fuel by year, for the 2010 SI wind scenario

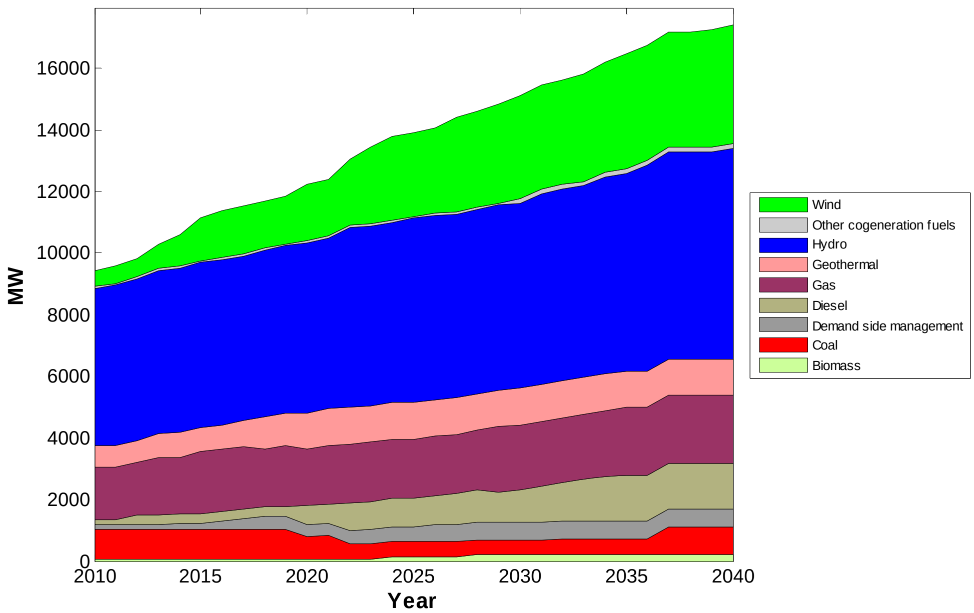


Figure 53 Capacity by fuel by year, for the 2010 Medium renewables scenario

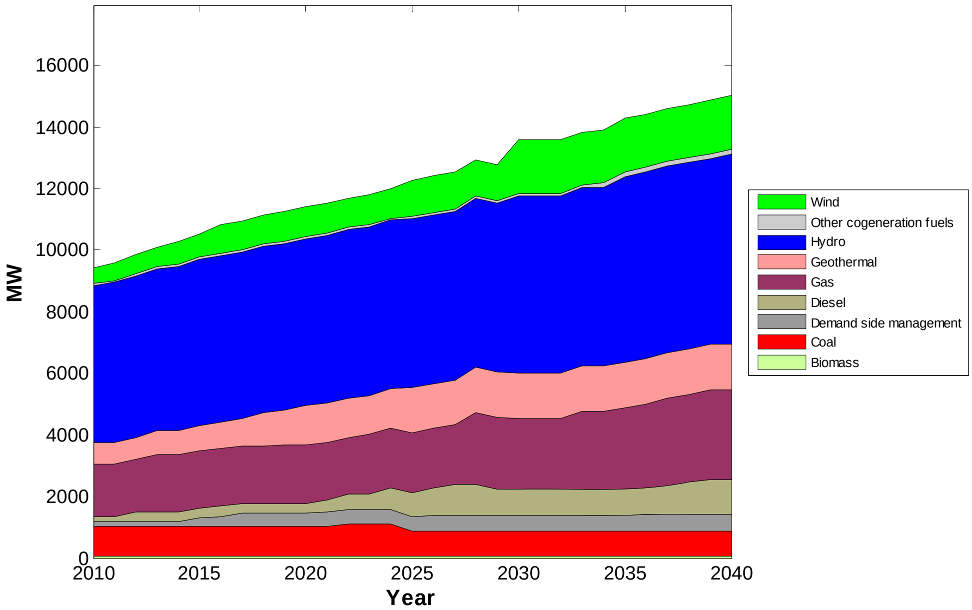


Figure 54 Capacity by fuel by year, for the 2010 Coal scenario

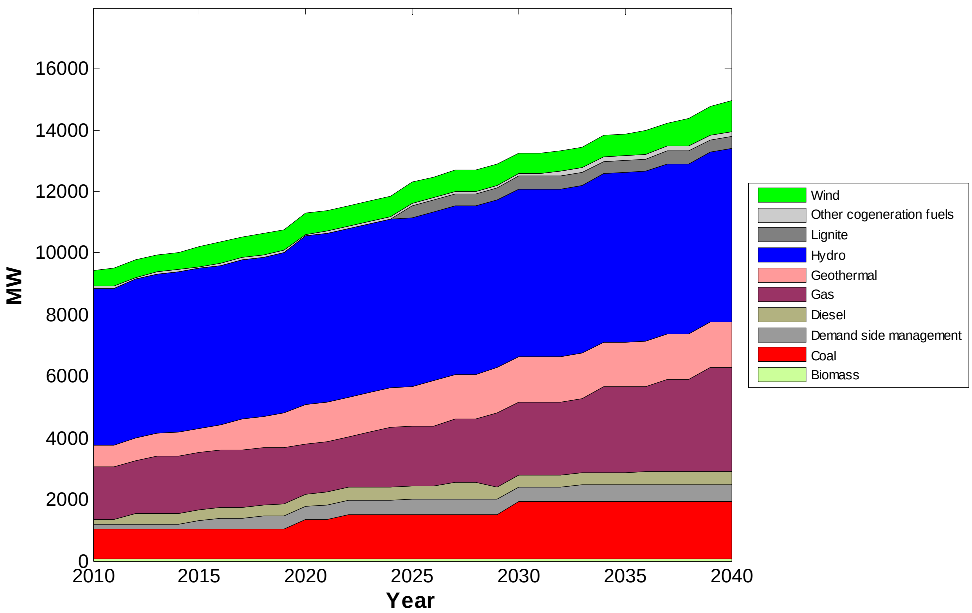
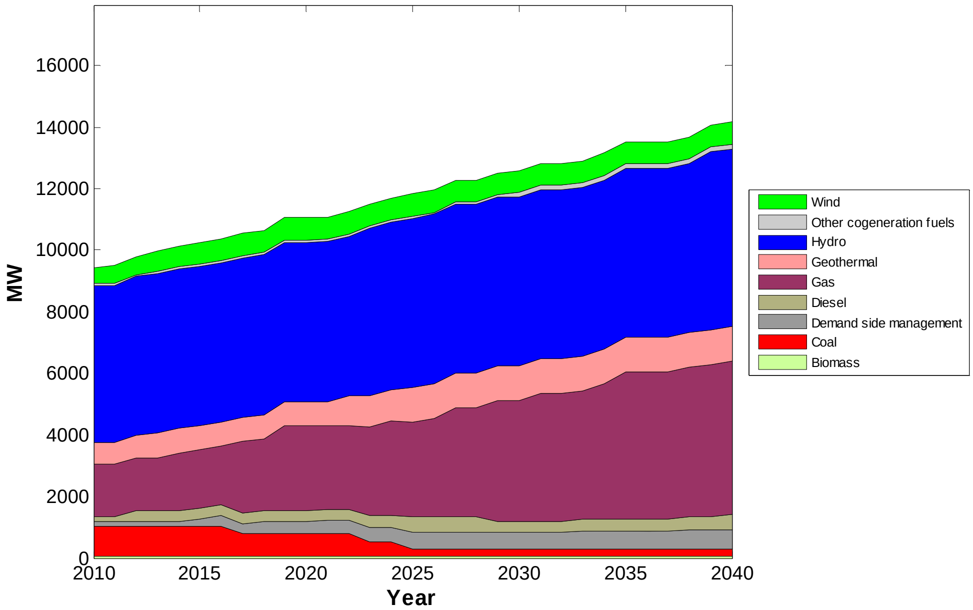


Figure 55 Capacity by fuel by year, for the 2010 High gas discovery scenario



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Appendix 12 Energy (GWh) by fuel and year, for each market development scenario

Figure 56 Energy by fuel by year, for the 2010 Sustainable path scenario

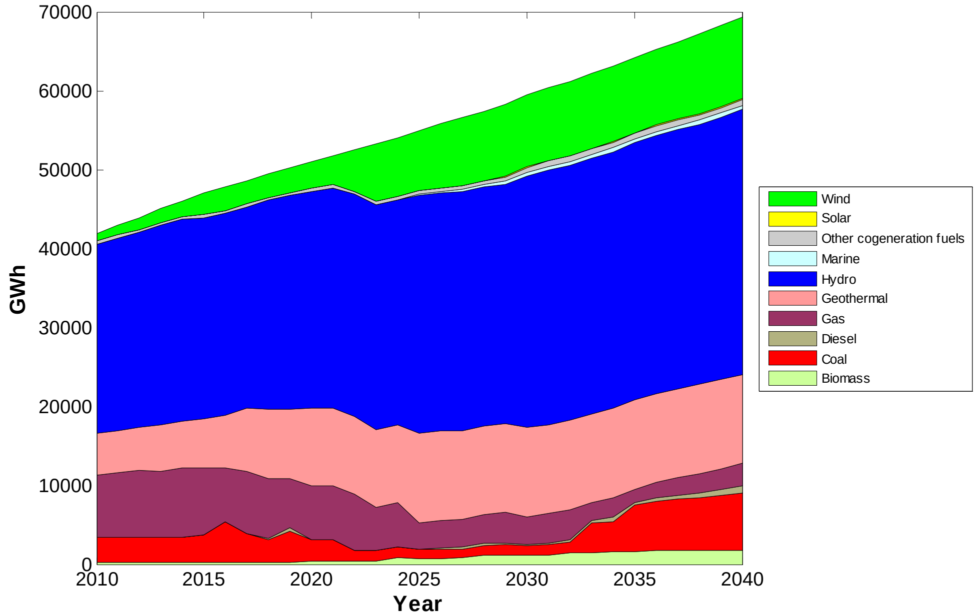


Figure 57 Energy by fuel by year, for the 2010 SI wind scenario

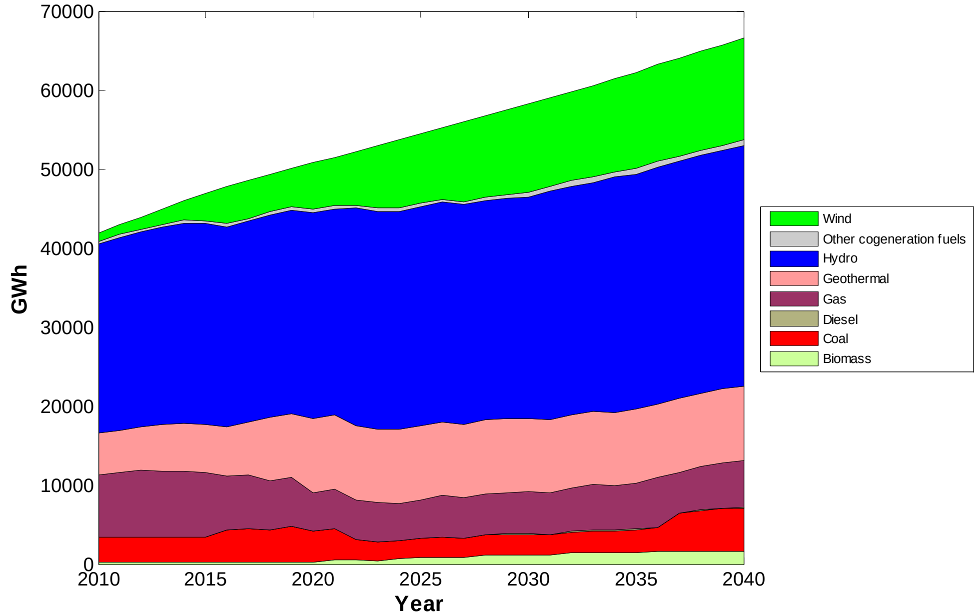


Figure 58 Energy by fuel by year, for the 2010 Medium renewables scenario

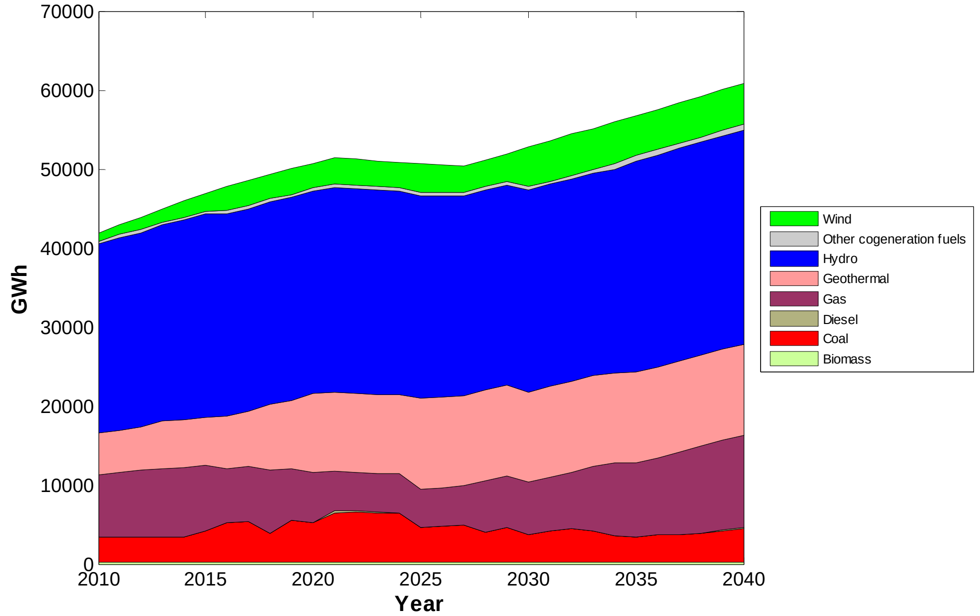


Figure 59 Energy by fuel by year, for the 2010 Coal scenario

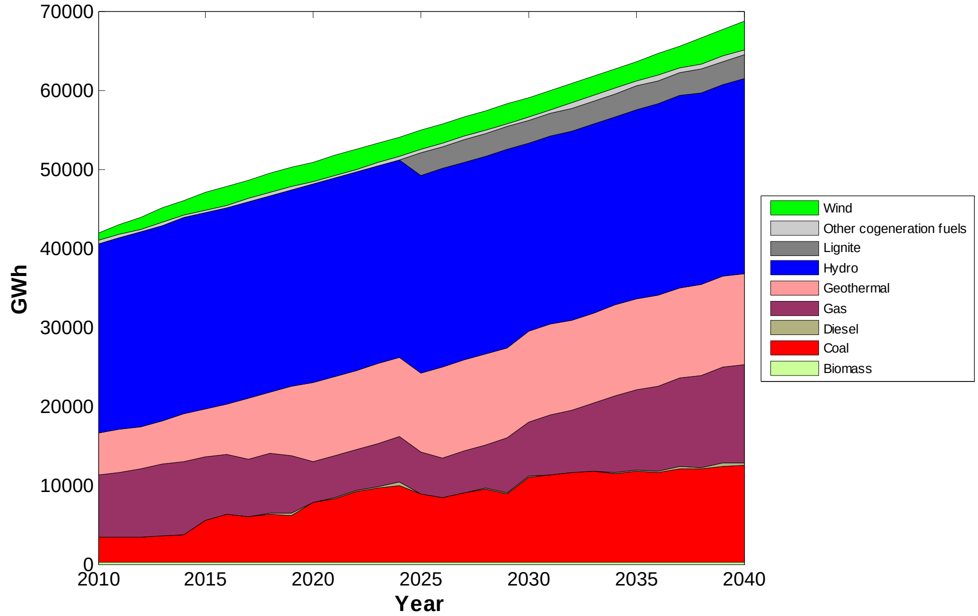
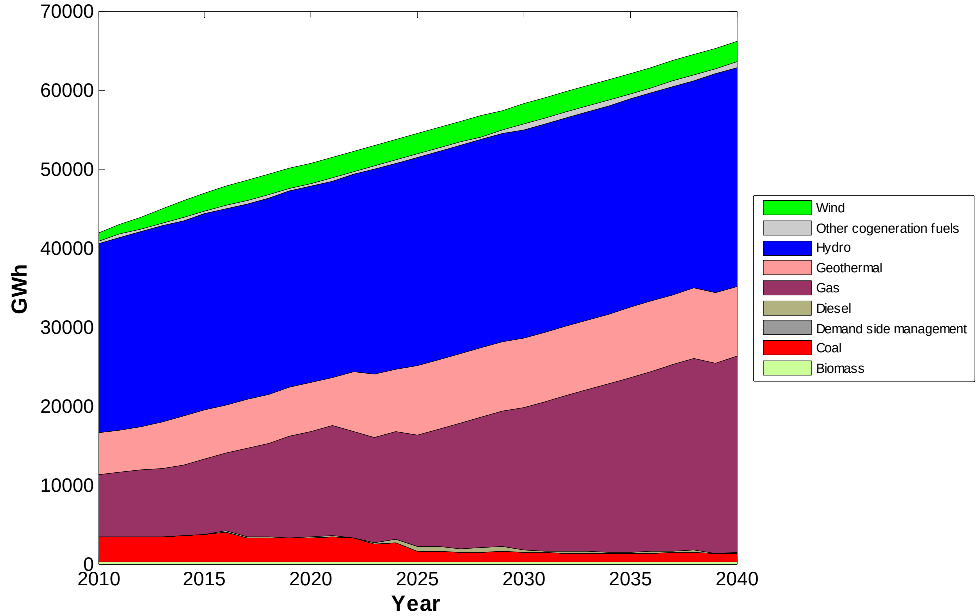


Figure 60 Energy by fuel by year, for the 2010 High gas discovery scenario



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Appendix 13 Energy (GWh) by technology, for each market development scenario

Figure 61 Energy by technology by year, for the 2010 Sustainable path scenario

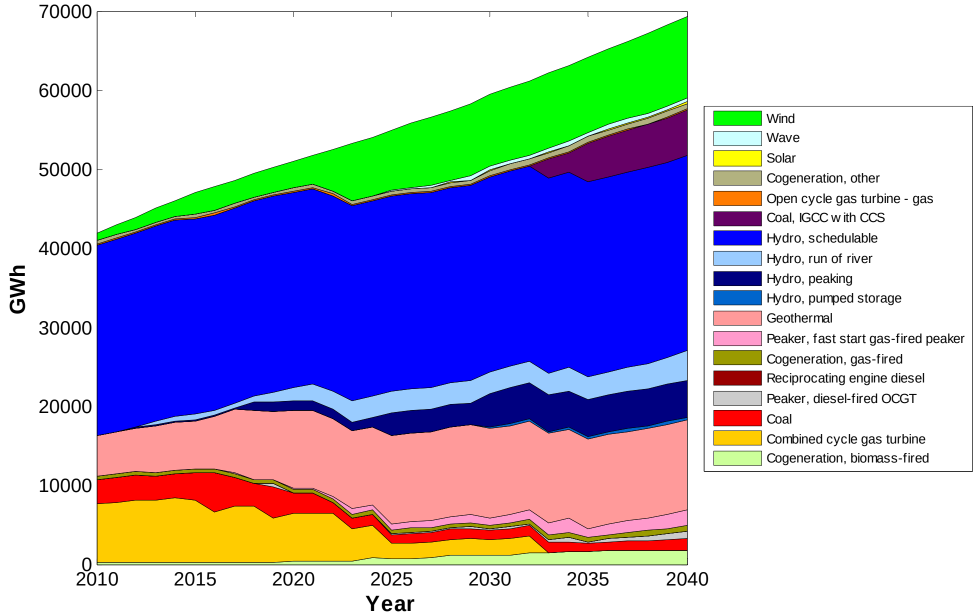


Figure 62 Energy by technology by year, for the 2010 SI wind scenario

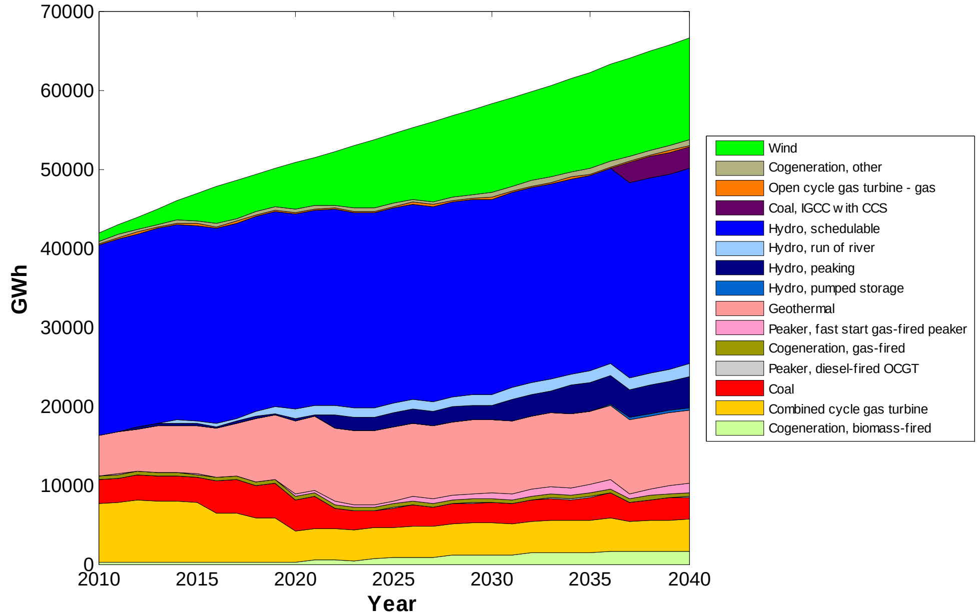


Figure 63 Energy by technology by year, for the 2010 Medium renewables scenario

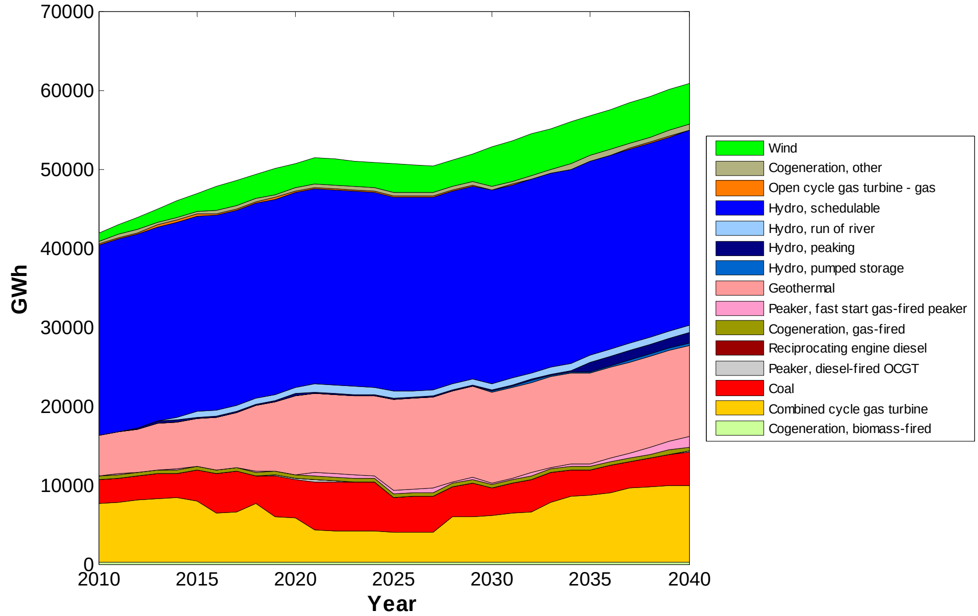


Figure 64 Energy by technology by year, for the 2010 Coal scenario

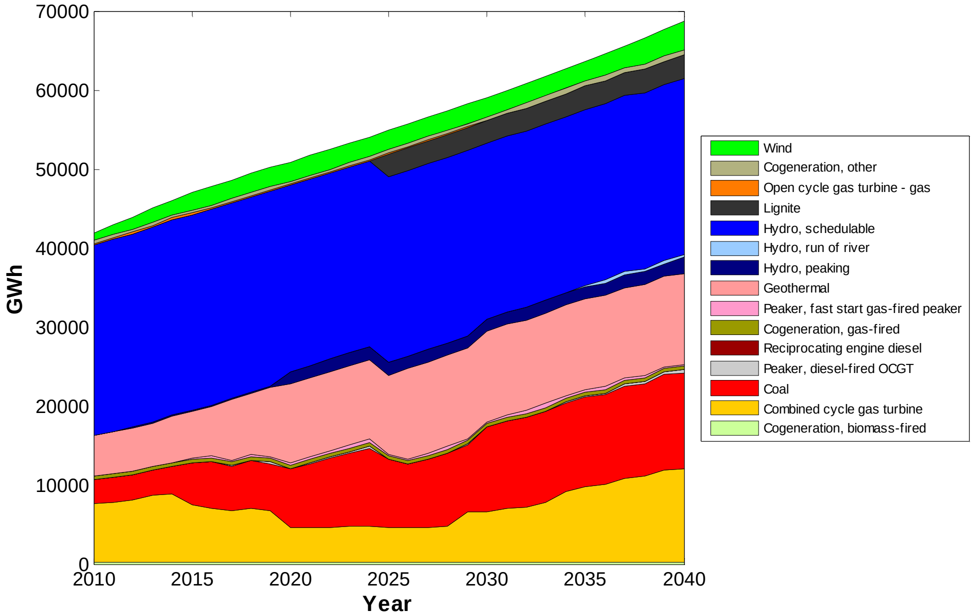
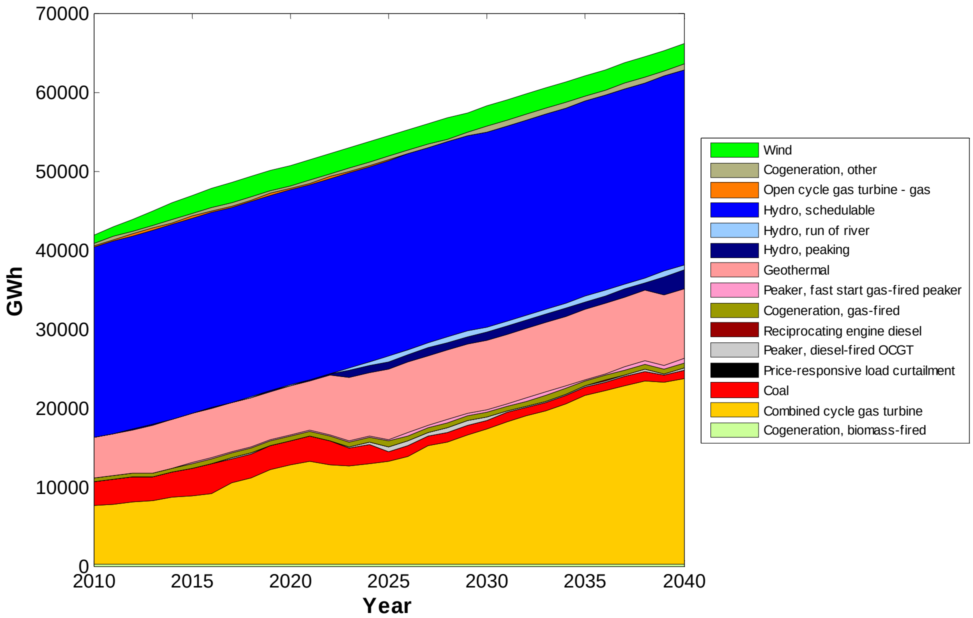


Figure 65 Energy by technology by year, for the 2010 High gas discovery scenario



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Appendix 14 Greenhouse gas emissions by technology and year, for each market development scenario

Figure 66 Emissions by technology by year, for the 2010 Sustainable path scenario

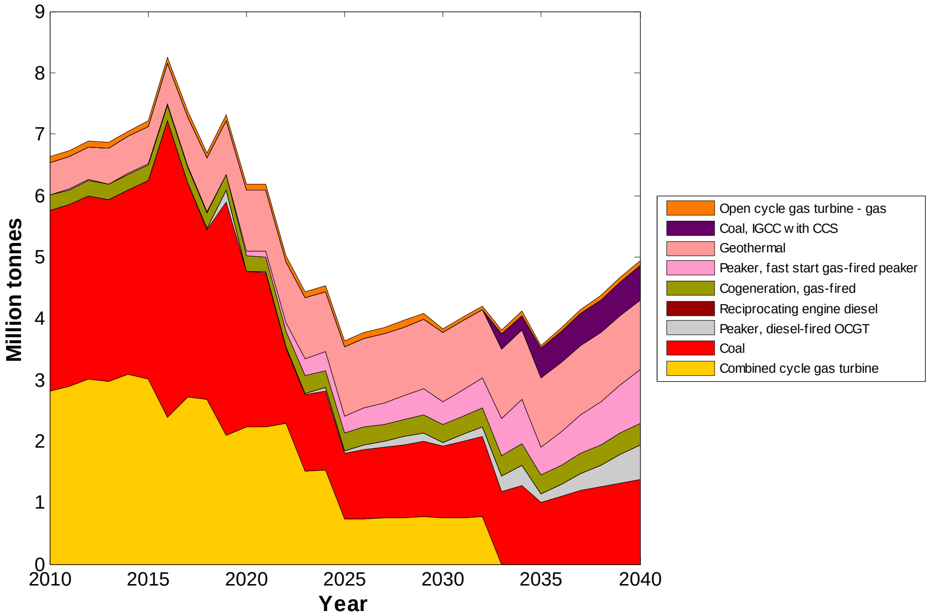


Figure 67 Emissions by technology by year, for the 2010 SI wind scenario

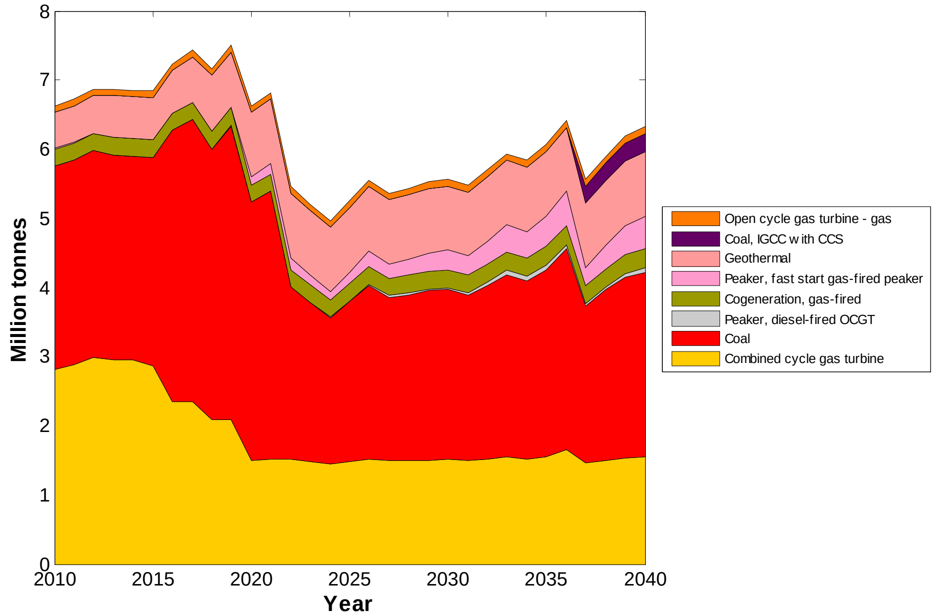


Figure 68 Emissions by technology by year, for the 2010 Medium renewables scenario

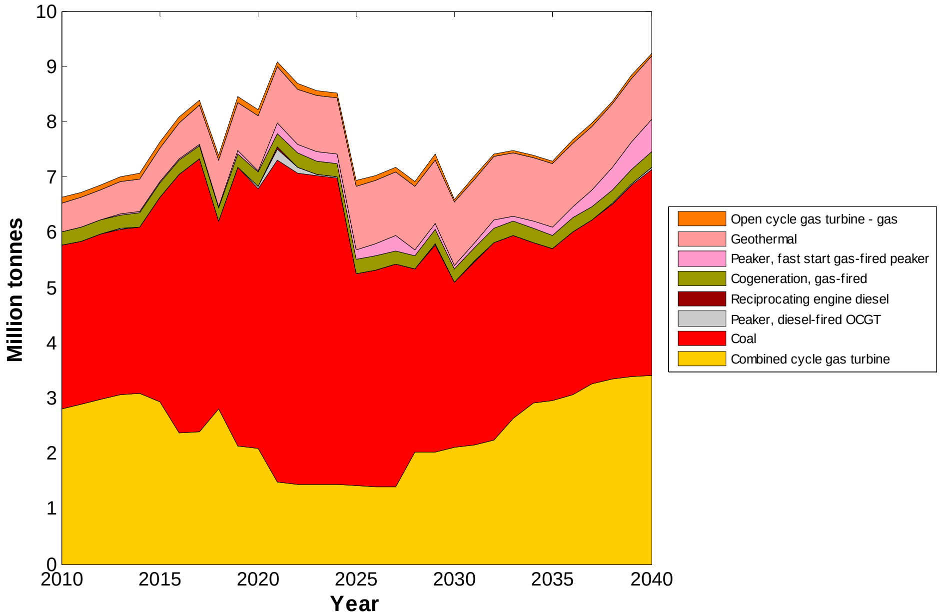


Figure 69 Emissions by technology by year, for the 2010 Coal scenario

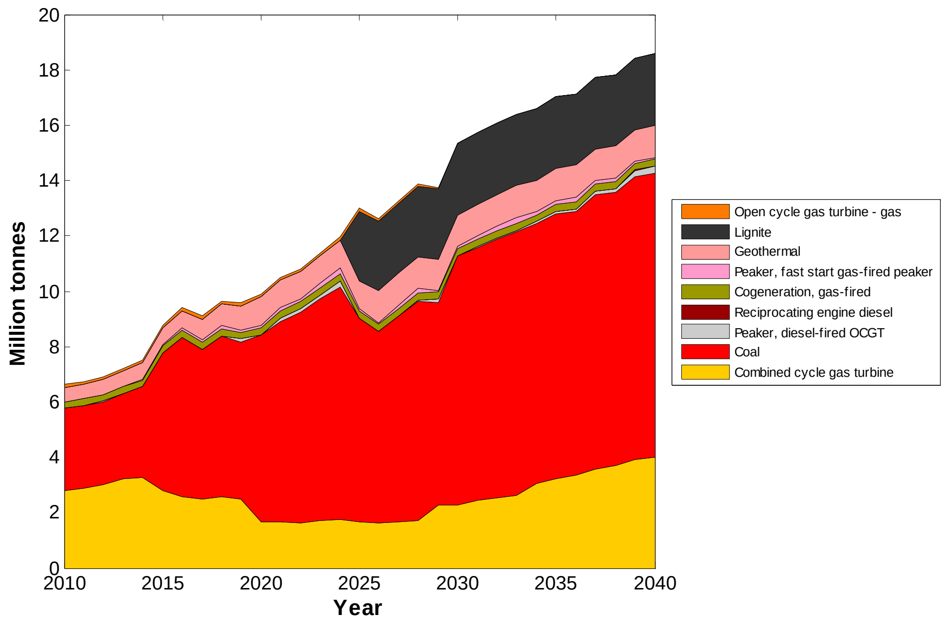
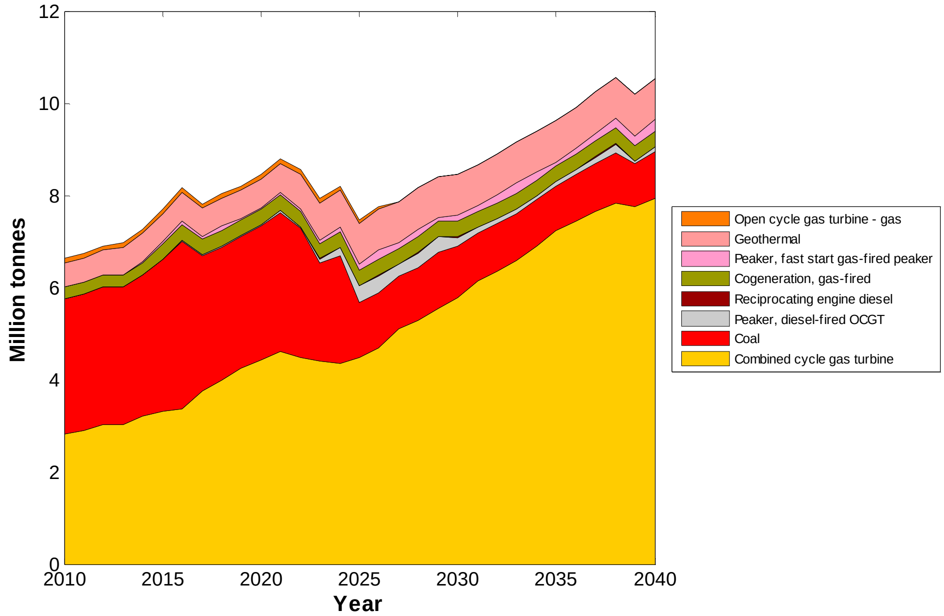


Figure 70 Emissions by technology by year, for the 2010 High gas discovery scenario



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Appendix 15 HVDC transfers

Figure 71 HVDC transfer for the 2010 Sustainable path scenario

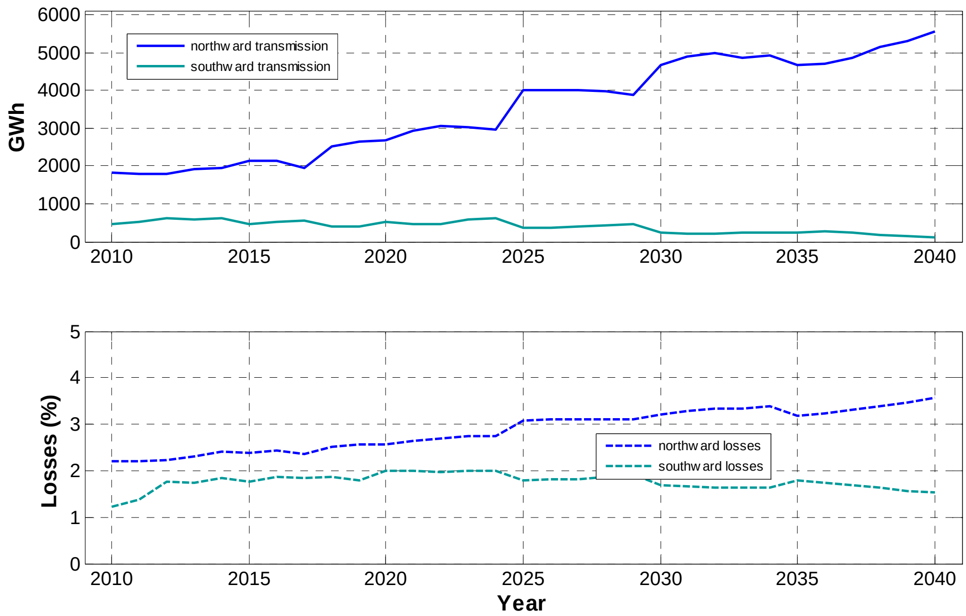


Figure 72 HVDC transfer for the 2010 SI wind scenario

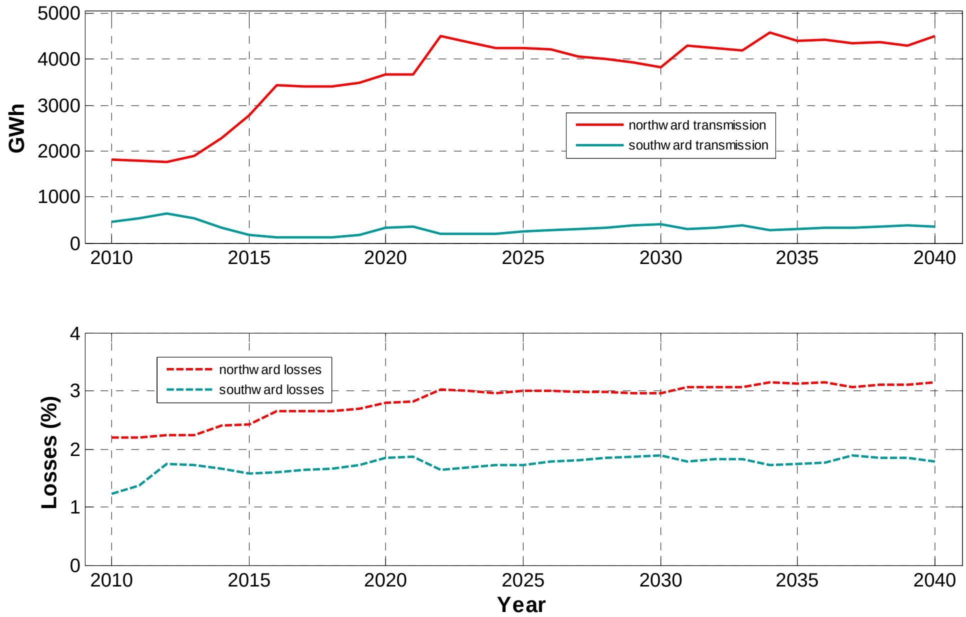


Figure 73 HVDC transfer for the 2010 Medium renewables scenario

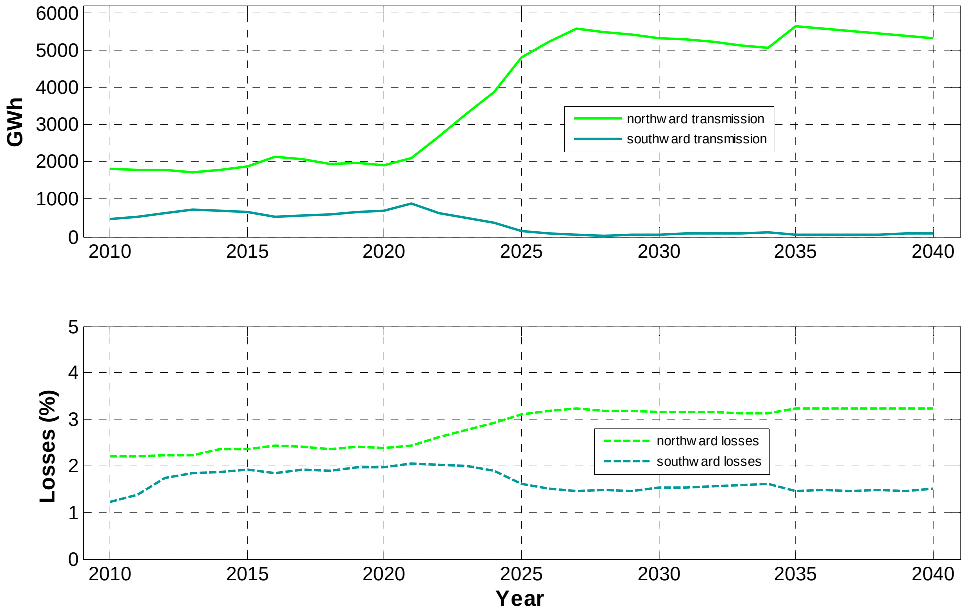


Figure 74 HVDC transfer for the 2010 Coal scenario

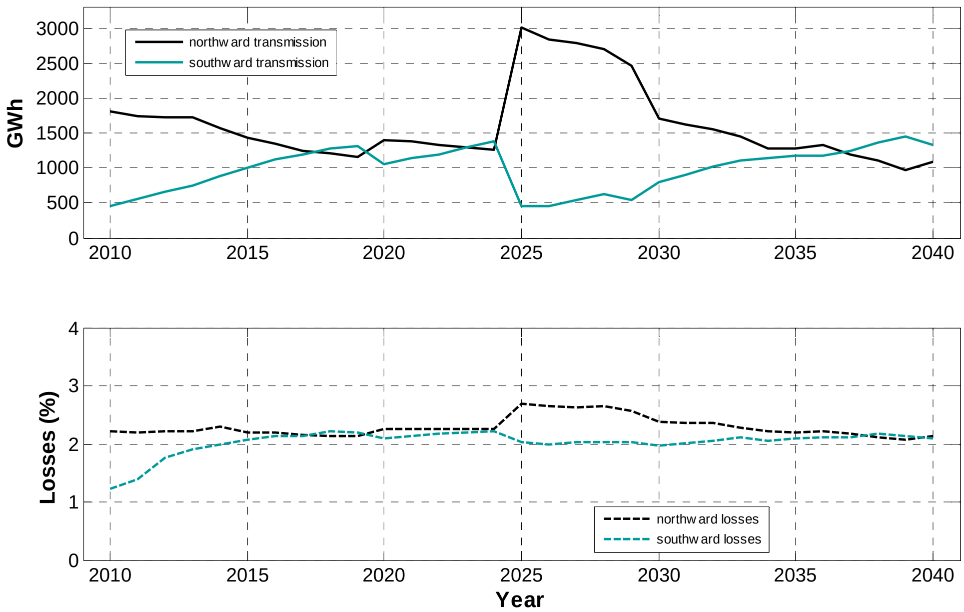
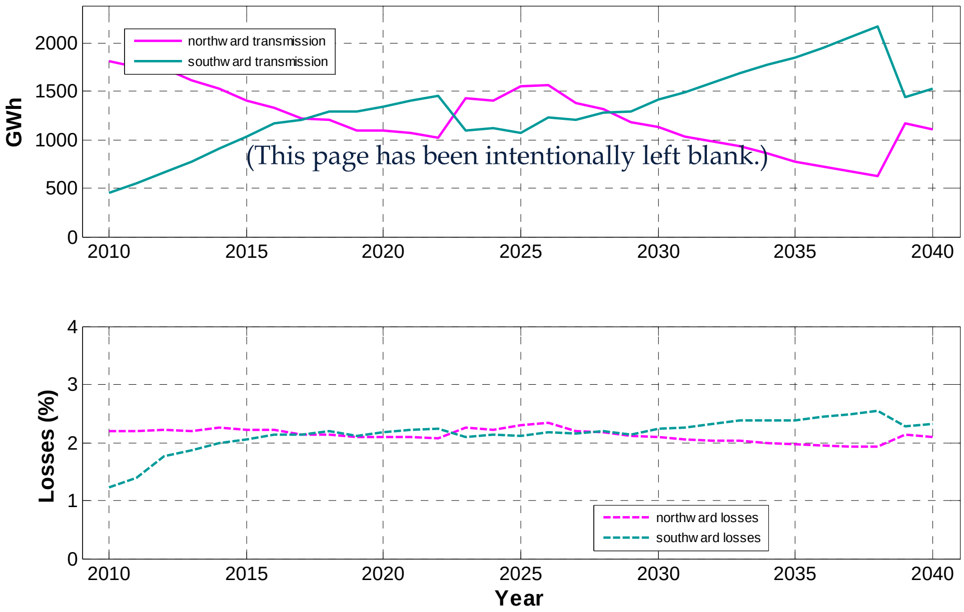


Figure 75 HVDC transfer for the 2010 High gas discovery scenario



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Appendix 16 Installed capacity by market development scenario and year, for each technology

Figure 76 Installed capacity of wind

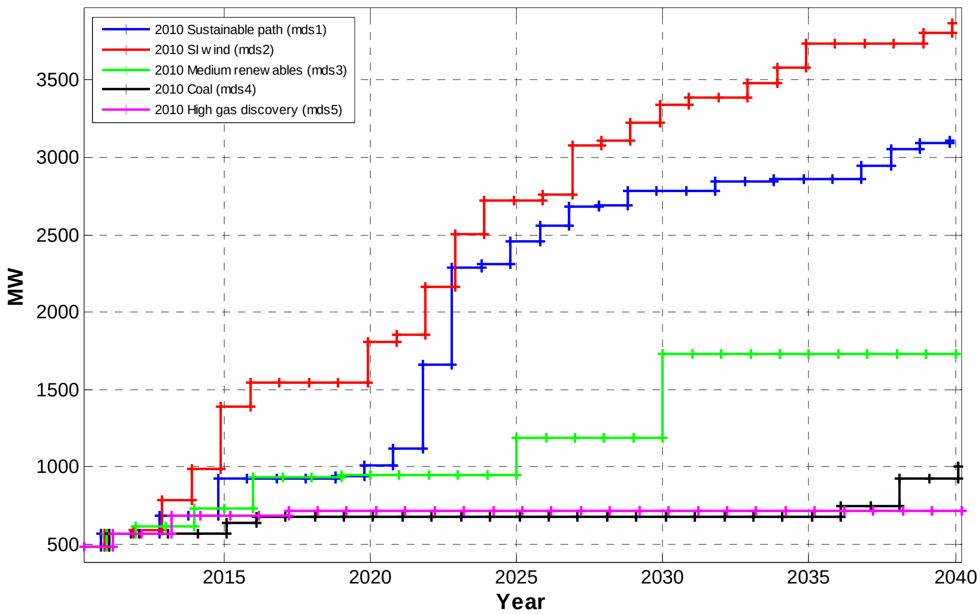


Figure 77 Installed capacity of co-generation, biomass-fired

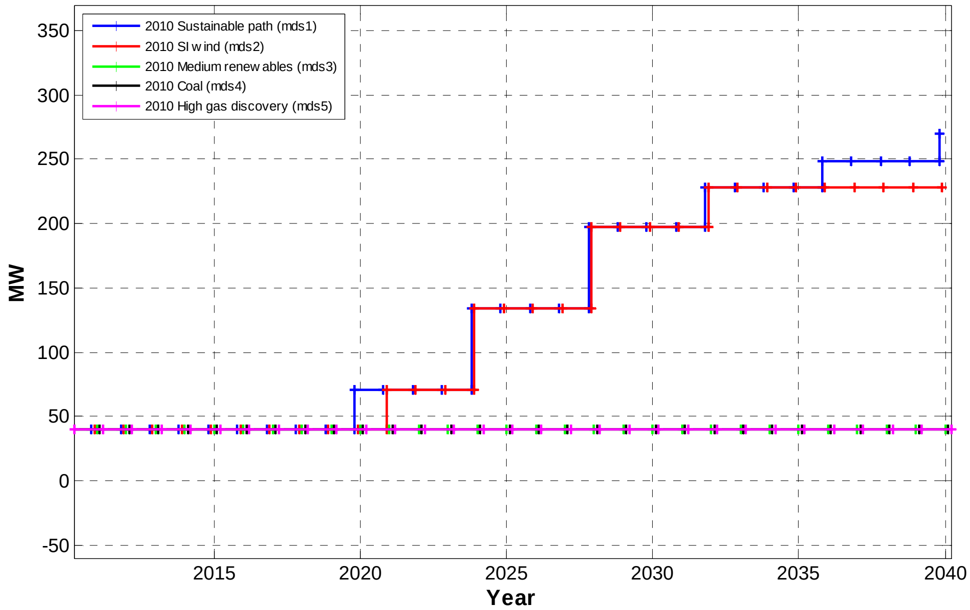


Figure 78 Installed capacity of gas

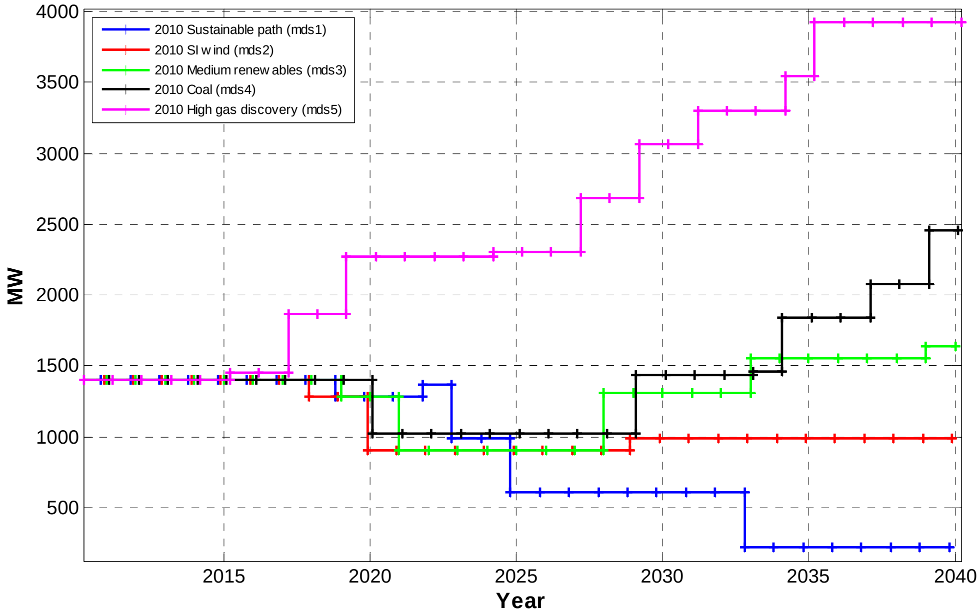


Figure 79 Installed capacity of geothermal

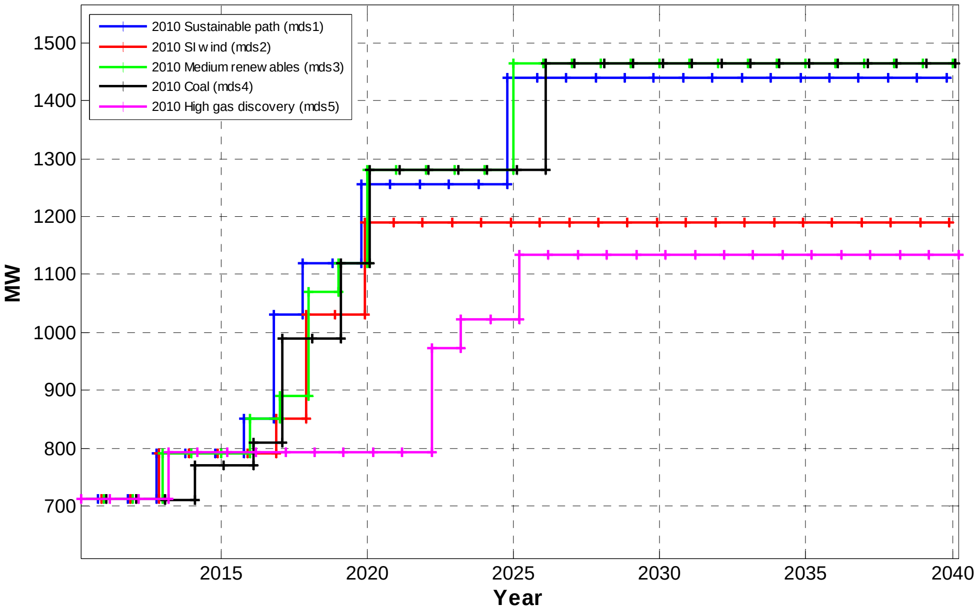


Figure 80 Installed capacity of hydro

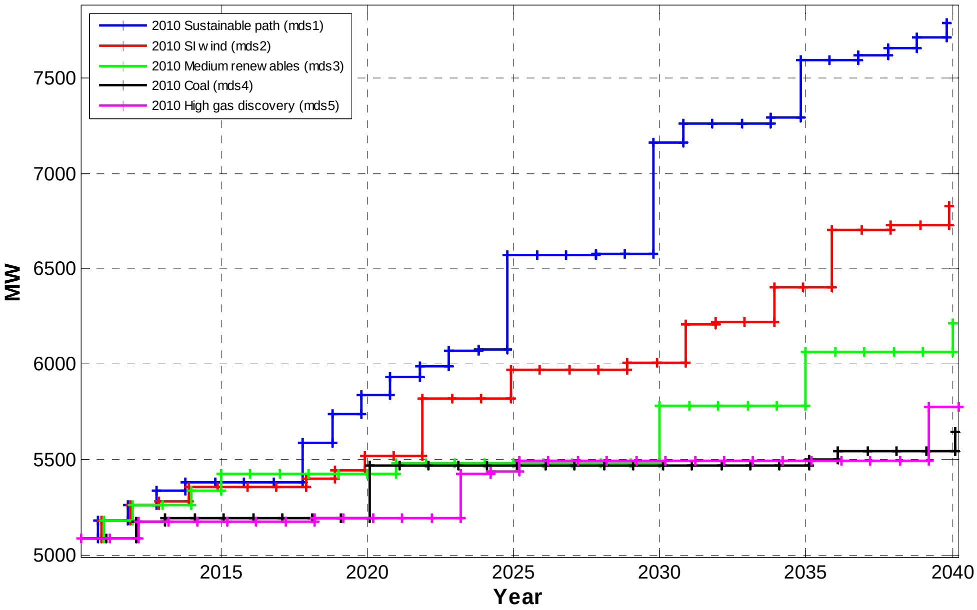


Figure 81 Installed capacity of IL and price-responsive load curtailment

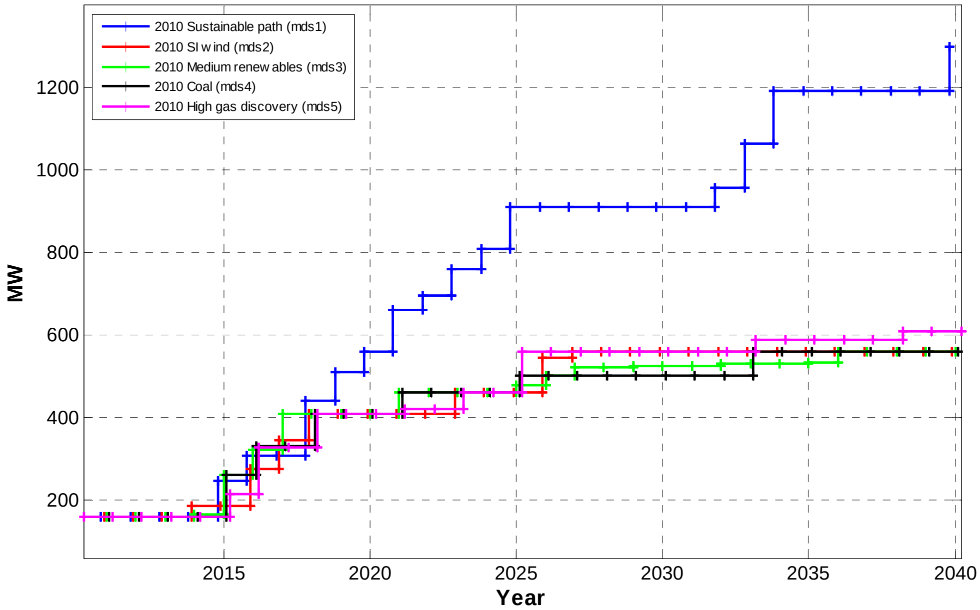


Figure 82 Installed capacity of peaker, diesel-fired open cycle gas turbine

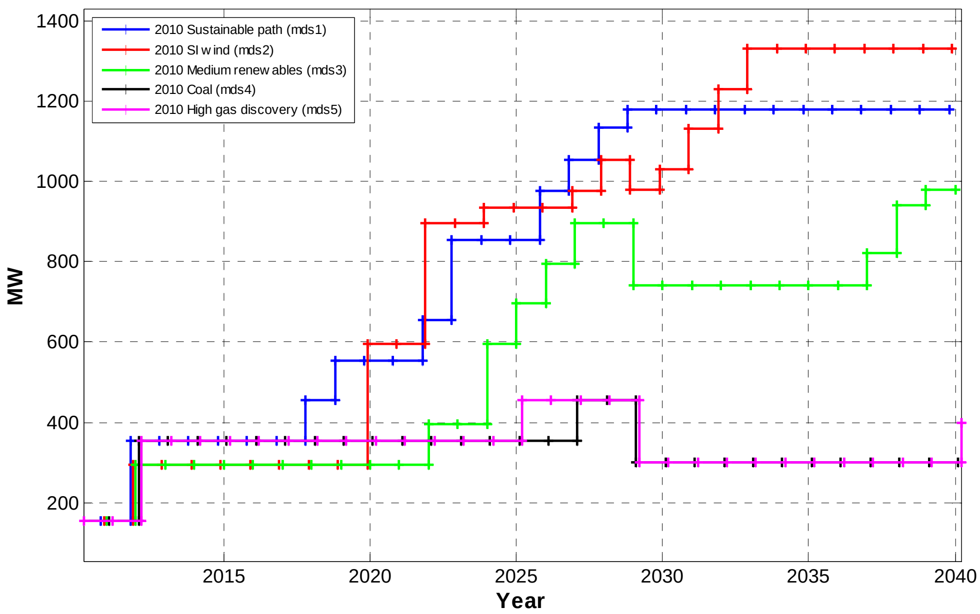


Figure 83 Installed capacity of gas peaker

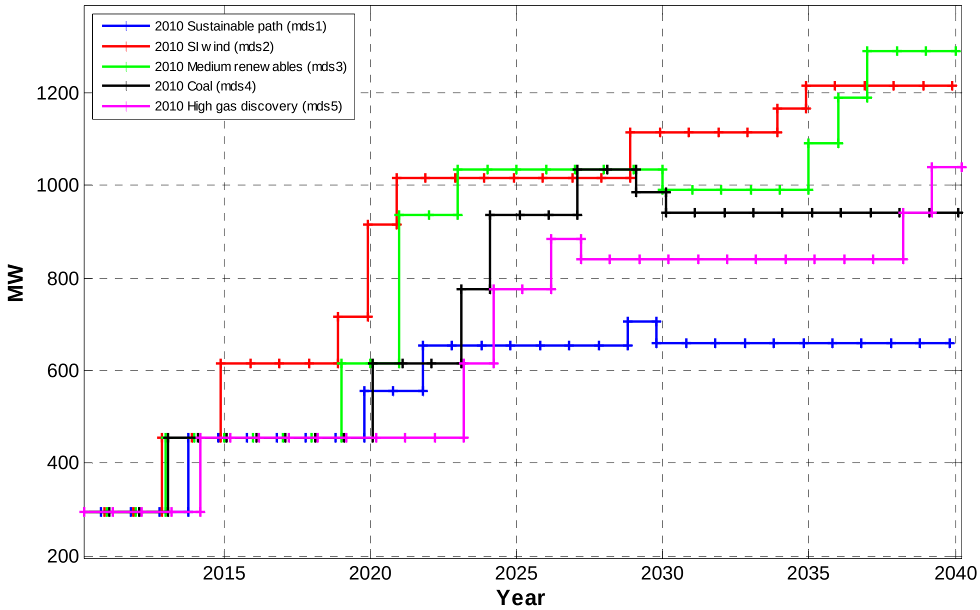


Figure 84 Installed capacity of reciprocating engines

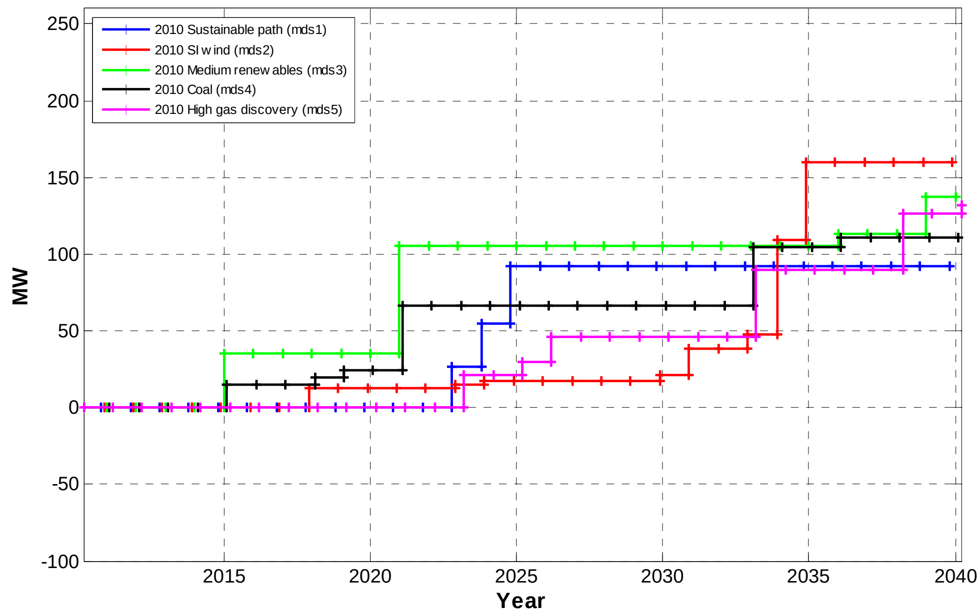


Figure 85 Installed capacity of coal

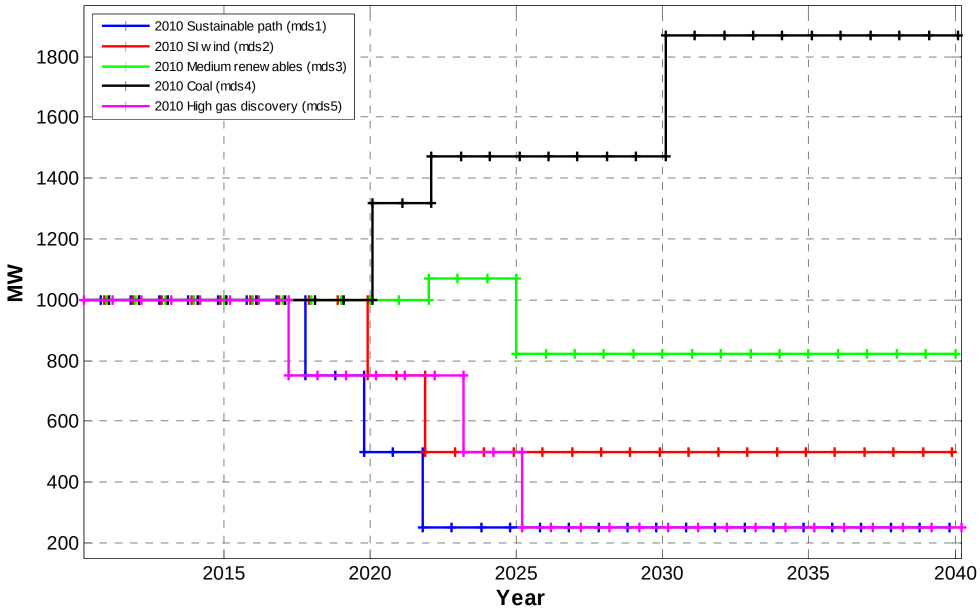


Figure 86 Installed capacity of lignite

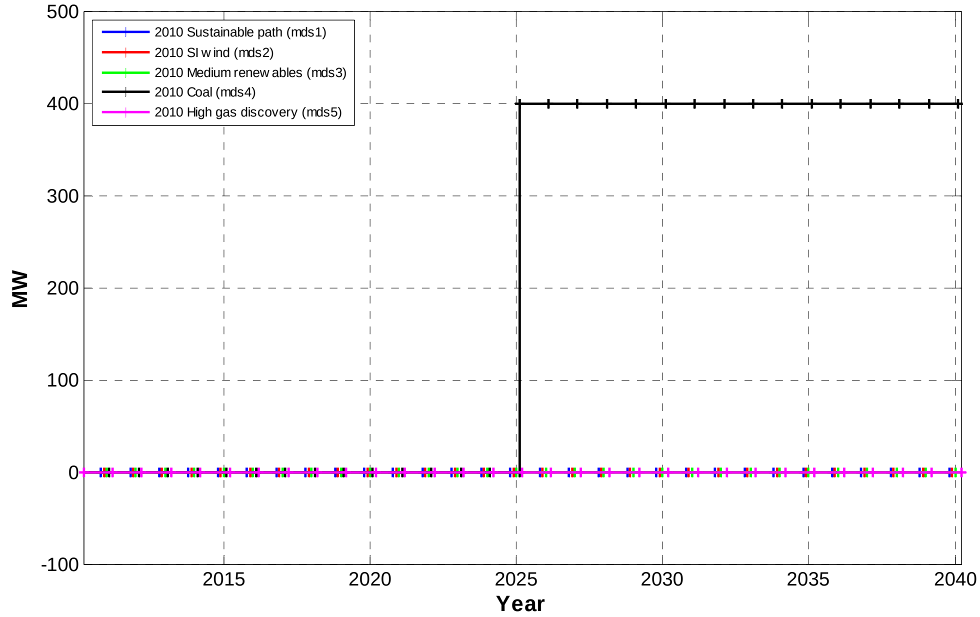


Figure 87 Installed capacity of carbon capture and storage

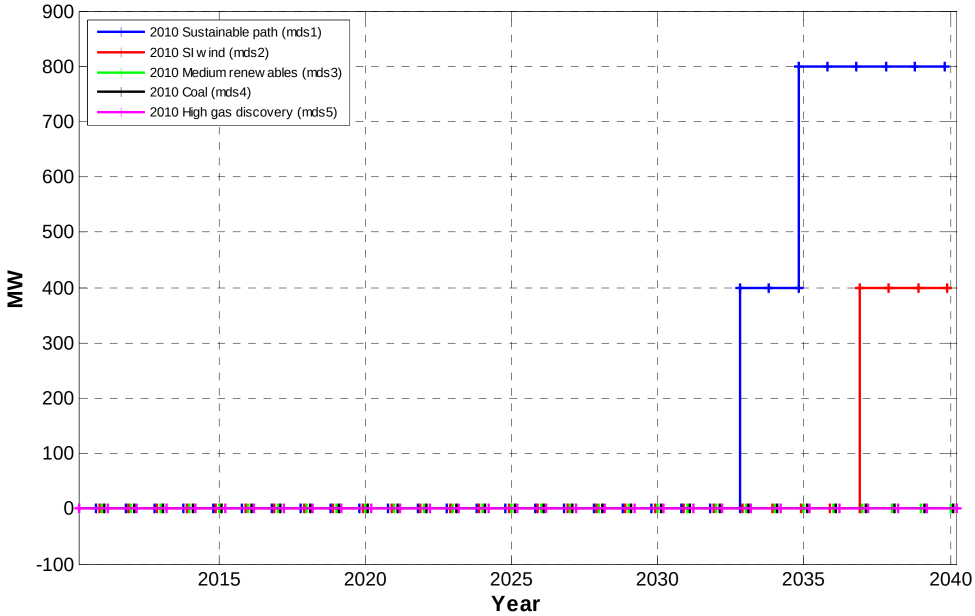


Figure 88 Installed capacity of solar generation

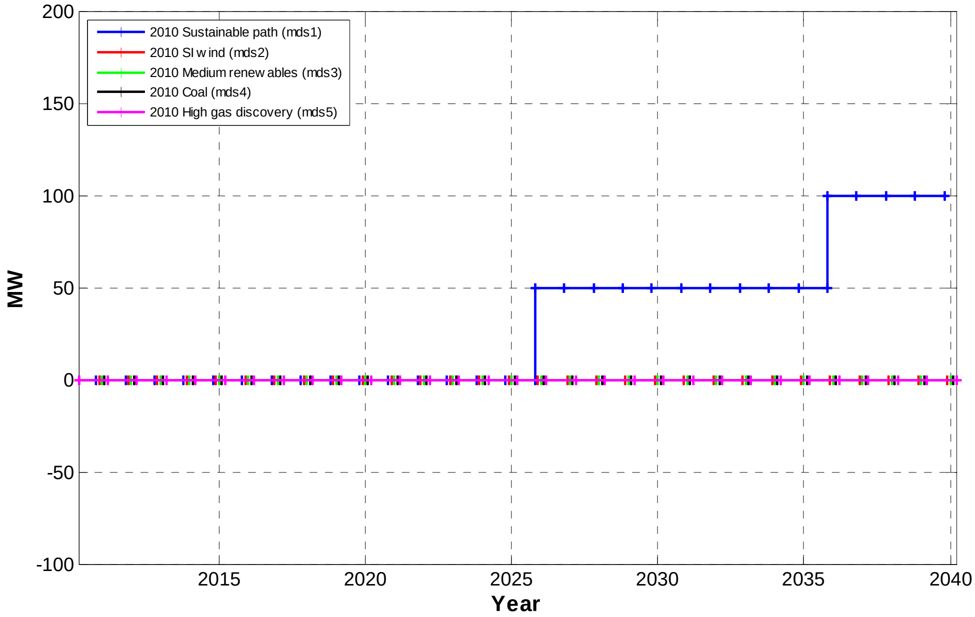
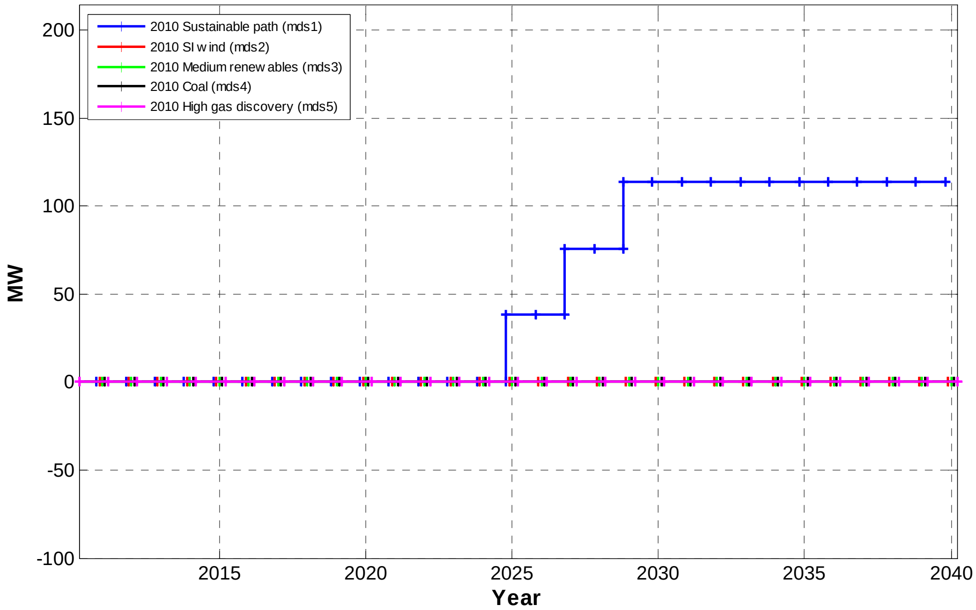


Figure 89 Installed capacity of marine generation



Appendix 17 Installed, firm, and North Island firm capacity for the five scenarios

Figure 90 Installed capacity

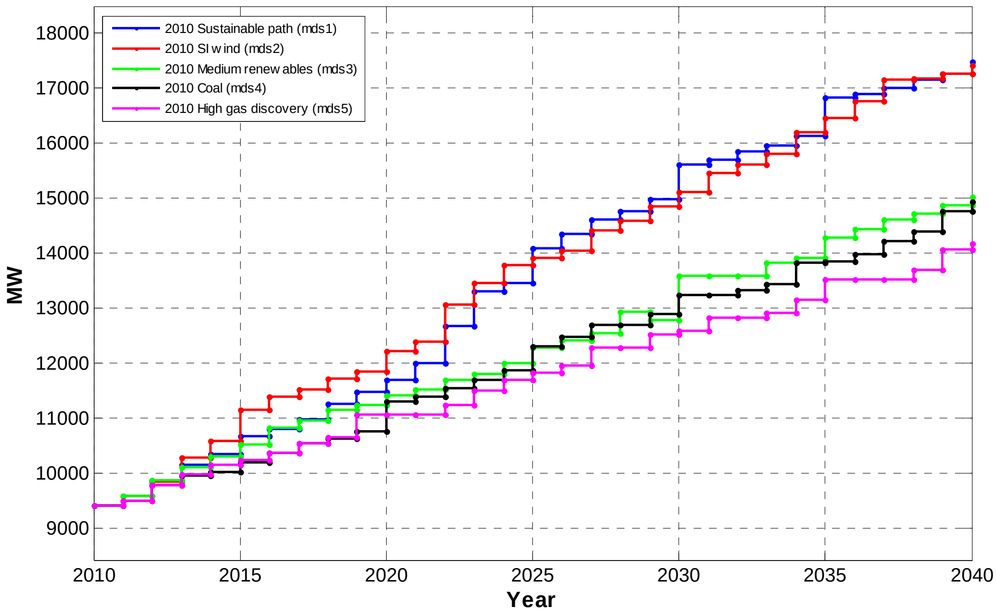


Figure 91 Firm capacity

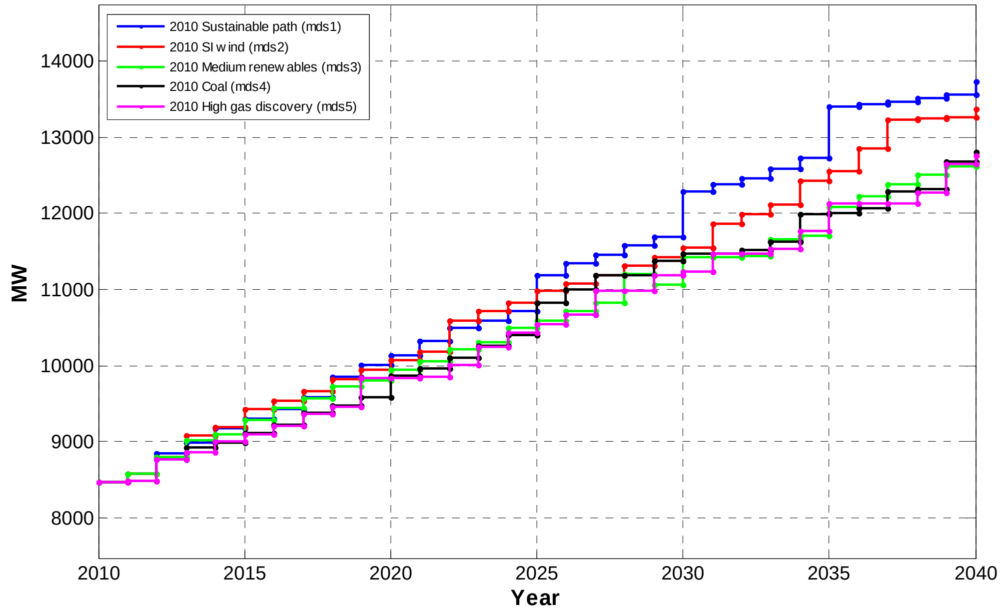
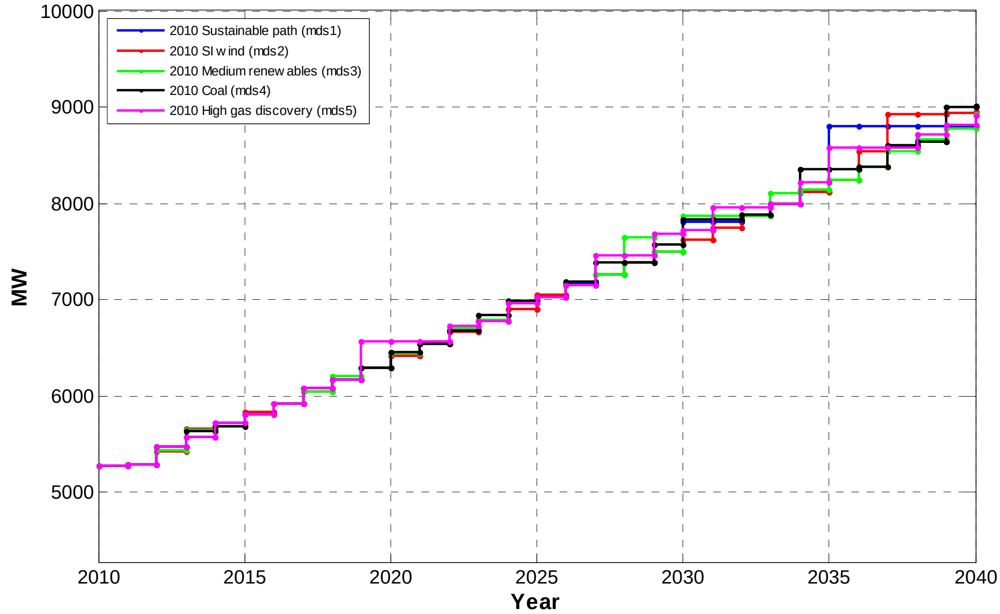


Figure 92 North Island firm capacity



Appendix 18 Details of approach to power systems analysis

Rule requirements and purpose of the PSA

Rule 9.1.1 of section III of part F of the Rules requires the SOO to include an analysis of the performance of the power system against the GPA and the GRS.

The PSA is presented in Section 8 by island and in Appendix 19 by region.

Approach to the PSA

The PSA uses a simplified approach to the consideration of whether the Grid meets the GRS, over the period covered by the GPA< by carrying out the analysis using only the deterministic limb of the GRS. This is likely in most cases to have a similar outcome as the use of the full GRS. Detailed application of the GRS would have involved a substantially greater amount of analysis, which is the responsibility of Transpower as the grid planner.

The need dates that are stated here imply a possible five-year window because the analysis is carried out in five-year steps. For example, if a transmission opportunity is identified as existing 'before 2020' then the actual need date could be anywhere between 2016 and 2020.

Market Development Scenarios

The generation build sequences provided as GEM outputs create market development scenarios that are based on providing sufficient capacity to meet the forecast national winter peak demand, and sufficient energy to meet the national annual energy demand. The GEM generation build sequences do not consider any transmission augmentations that may be required to deliver the power to the demand.

Key information and assumptions

Planning horizon

The PSA considers a 30-year planning horizon from 2010 to 2040. In the analysis the planning horizon is broken into five-year intervals with 2010 being the benchmark year.

Generation dispatch

The power-flow model implemented in the 2008 SOO for all of New Zealand has been updated to represent peak operating conditions forecast from 2010. To initialise, generation was modelled to be dispatched to represent winter peak conditions, as described below.[74]

For peak winter demand, all North Island generation plant was modelled to be set to its maximum output, with the following exceptions:

- wind generation was dispatched at 20 per cent active power output and 100 per cent reactive power capacity;
- Otahuhu B (1 x 360MW) was disconnected to represent the effect of an unplanned outage of a large unit on both Auckland and the rest of the country;
- in Hawke's Bay, one Piripaua unit was disconnected to represent the effect of low hydro generation in the region. The reserve generation at Whirinaki (3 x 52MW) was also disconnected unless required in the event of a generation shortfall.

With the above North Island generation dispatch, the HVDC link was modelled to be set to maintain the North Island slack bus within its generating limits.

With the HVDC set, the South Island peaking generators (hydro, gas or coal) were then modelled set to maintain the South Island slack within its generating limits, with the following exceptions:

- in the Upper South Island, Cobb generation was restricted to 50 per cent output (17.1MW) to represent the effect of low hydro generation in the region;
- on the West Coast, Arnold (1 x 3MW) was disconnected and the Kumara/Dillmans scheme (11MW) was restricted to 4.5MW.

Manapouri generation was modelled to be limited to 721MW unless a generation scenario indicated that a higher output would be reliably available.

Dry-year dispatch not explicitly studied in the PSA

The PSA does not explicitly study the network's capacity to transfer energy south during off-peak periods such as dry years because the generation scenarios already take into account the capacity of the network to do this transfer.

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74 This generation dispatch was automated to give consistency across all scenarios and years.

The Commission did not study dry-year dispatch as it is expected that market participants would effectively manage hydro storage using the capability of the grid to transfer power from North to South during periods of low demand.

HVDC upgrade

When analysing energy loads for 2010, the Commission assumed that the HVDC Link operates with only Pole 2 (700MW) in service.

When analysing energy loads for 2015, the Commission assumed that a new Pole 3 was added, bringing the total HVDC bipole capacity to 1200MW.

Demand forecast

The ADMD prudent peak forecasts discussed in Section 3.4.2 were used in the PSA.

Forecasts are the same across the different scenarios, although varying levels of demand-side management, interruptible load and load curtailment were modelled across the separate regions for different scenarios. In particular, the Tiwai Point aluminium smelter is assumed to be decommissioned in the Medium Renewables scenario only, in stages from 2022 to 2027.

No explicit allowance was made for fluctuations due to extreme weather conditions. This was because the demand forecasts used already allow for extreme weather conditions in the early years where timing of new investments is more critical than the later years in the horizon.

It was assumed that the winter peak will have national diversity factors applied to the GXP peak loads. It should be noted that the use of national diversity factors will result in slightly lower regional loads than the use of regional diversity factors. However, this was not considered to be significant in the context of a 30-year horizon.

From 2020 onward it was assumed that the demand power factor has improved to unity on the low voltage side of GXP supply transformers in the Upper North Island and Upper South Island.

As the demand for energy grows the supply transformer capacity will need to be augmented to provide a secure supply to the load on the low voltage supply buses. Modelling these supply transformer augmentations is likely to involve a considerable amount of work and there is a large uncertainty in the nature of the augmentation because individual GXP demand growth is harder to forecast than national demand growth. On the other hand, not modelling the augmentations will result in an unrealistically high reactive consumption in the supply transformers.

Instead of augmenting supply transformers the analysis took the approach of maintaining a constant load power factor as viewed from the high voltage side of GXP supply transformers and eliminating the supply transformers.

For the Upper North Island and Upper South Island the analysis assumed a 0.99 lagging power factor as viewed from the high voltage side. This was consistent with the new connection code which requires a unity power factor so that off-take customers in these regions do not draw reactive power from the grid at peak times.

For other loads the analysis assumed a 0.96 lagging power factor as viewed from the HV side. (The value for power factor was determined by averaging all of the high voltage side power factors at peak load. The average winter peak power factor was found to be about 0.96 lagging).

Note that 220/110kV inter-connecting transformers were still added or upgraded explicitly where there was a need for such upgrades. Where there was a mix of generation and load on the low voltage side, the analysis did not eliminate the transformers.

Performance criteria

The security criteria that were assumed for this study were generally based on the *N – 1* single contingency criteria described in Transpower's 'Main Transmission System Planning Criteria',[75] allowing for the generation outages described in paragraph 16.

However, supply to Auckland is based on *N-G*-1, which is the security level that will be achieved when Transpower's North Island Grid Upgrade is completed.[76]

The credible single contingency events that were considered in the PSA are those defined in the Rules, which are the following:

(a) a single transmission circuit interruption;

(b) the failure or removal from operational service of a single generating unit;

(c) an HVDC link single pole interruption;

(d) the failure or removal from service of a single bus section;

(e) a single inter-connecting transformer interruption;

(f) the failure or removal from service of a single shunt connected reactive component.

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[75] Main Transmission System Planning Criteria', Transpower New Zealand Limited, March 2005.

[76] *N-G*-1 security means that the system is in a secure state with all transmission facilities in service, and in a satisfactory state following a generator outage and a credible single contingency event.

It was assumed that in the event of a large generator tripping or HVDC pole tripping, reserves might be made up from a combination of spinning reserve, interruptible load and HVDC overload capacity.

The PSA assumes that the following system performance criteria would be maintained for normal operation and following a single contingency.

- Transmission circuits can be loaded up to 100 per cent of winter or summer rating.
- Interconnector transformers can be loaded up to 120 percent of rating (except where overload ratings for specific transformers are known).
- Voltages are maintained in the range 0.90 – 1.10 pu at all buses (after capacitor switching and tap changing).
- Fault levels at selected bus bars will be recorded for information purposes only. The analysis is not intended to specifically study augmentations to limit fault levels.

The PSA did not take into account PV curve or dynamic analysis because the analysis is intended to be an overview rather than a detailed design study.

Selection of transmission augmentation

As outlined above, the PSA identifies possible transmission augmentations as required to maintain the system. Performance criteria in each of the study years were selected in the following order.

- Committed transmission projects discussed in Transpower's 2010 Annual Planning Report.
- Transmission opportunities, namely:
  - other possible transmission projects discussed in Transpower's 2010 APR that are transmission opportunities;
  - other projects identified to alleviate potential security issues.

When selecting transmission opportunities, the PSA's modelling favours lower cost upgrades in preference to new lines where possible.

The PSA assumed that the existing 220kV grid will continue to be augmented with new 220kV lines. (The committed 220/400 kV line from Whakamaru to Pakuranga will be upgraded from 220kV to 400 kV when required.)

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Appendix 19 Power systems analysis by region

North Island transmission analysis

Northland

The Northland regional demand is forecast to increase from around 910MW in 2010 to around 1700MW by 2040.

The region is currently supplied from the south by a 220kV double circuit Henderson- Marsden transmission line and a 110kV double circuit Henderson-Maungatapere line. From Maungatapere there is a 110kV double circuit line to Kensington and a 110kV double circuit line to Kaikohe with a single circuit line continuing to Kaitaia. These circuits provide an adequate supply into the region for the near future with little transmission augmentation planned or committed.

The region has a small amount of generation in the form of the Ngawha geothermal power station, although this plant is assumed to be decommissioned in 2020 in the Sustainable Path scenario. A medium-sized (85MW) gas-fired generating unit is modelled at Marsden around 2025 in the Sustainable Path and South Island Wind and in 2040 in the Medium Renewables scenarios, and a large (300-400MW) coal-fired generating plant is modelled, from 2020, in the Medium Renewables and Coal scenarios. In the Medium Renewables, Coal and High Gas Discovery scenarios, a large (up to 480MW) CCGT plant is modelled at Rodney around 2035. Up to 570MW of wind generation is modelled in the region for the Sustainable Path, South Island Wind, Medium Renewables and Coal scenarios. Overall, the Sustainable Path scenario offers the least new generation (approximately 500MW, 270MW of which is wind generation), while the Medium Renewables scenario offers the most generation (1100MW, of which 320MW is wind).

Despite the differences in the generation scenarios, few future transmission opportunities are identified. There is a transmission opportunity to supply Dargaville before 2015, modelled as an upgrade to the 110/50 kV interconnecting transformer at Maungatapere. Between 2015 and 2040 additional interconnection capacity and reactive support may be required at Marsden, dependent on future generation on the 110kV network. Likewise, the Sustainable Path (by 2020) and High Gas Discovery (by 2035) scenarios suggest that there is a transmission opportunity to upgrade the supply to Kaikohe. This is modelled as an upgrade to the 110kV double circuit Maungatapere–Kaikohe line. In the Sustainable Path scenario, opportunities for increased reactive support are also identified at Maungatapere by 2015 and at Kaikohe by 2040. Around

2035, opportunities for upgrades to protection equipment offer an increase in 110kV transmission capacity between Marsden and Maungatapere.

North Auckland

The North Auckland transmission region feeds Northland as well as northern parts of Auckland. As discussed in the previous section, the Northland demand is forecast to increase from around 910MW in 2010 to around 1700MW by 2040. In addition to this, Auckland demand is forecast to increase from around 1470MW in 2010 to over 3100MW by 2040.

The existing transmission in this region is currently supplied, through North Western Auckland from Otahuhu substation, by a 220kV Henderson – Otahuhu double circuit line. In addition to this there are two double circuit 110kV transmission lines from Otahuhu to Mount Roskill: one through Mangere to Mount Roskill and another passing through (but not connected to) Penrose. These 110kV lines are of relatively low capacity and sections of them are nearly fully utilised.

The future generation scenarios align with those described for the Northland region.

Substantial transmission augmentation is planned for this region. Under the North Auckland and Northland project, Transpower has committed significant augmentation to the existing transmission network. Current and recently completed projects include:

- +/- 100 MVAr SVC at Albany (completed project);
- 50 MVAr capacitor at Hepburn Rd (completed project);
- closure of Mt Roskill-Hepburn Rd 110kV split (completed project); and
- remove Otahuhu-Henderson and Henderson-Huapai 220kV circuit equipment constraints (committed project);
- a new cross-harbour interconnection through Auckland before 2015, being a 220kV cable from Penrose substation to Hobson Street substation, across the Auckland Harbour Bridge to the Wairau Rd substation and then onto Albany substation (committed project).

Other transmission opportunities may include an increase in the interconnecting 220/110kV capacity at Henderson. Increases in 110kV transmission capacity between Henderson and Hepburn Road and between Henderson and Wellsford are also identified opportunities.

Auckland

Auckland demand is forecast to increase from around 910MW in 2010 to around 1700MW by 2040.

Auckland is currently supplied from the south by 220kV and 110kV transmission lines with interconnecting transformers at Otahuhu and Penrose substations. Reactive voltage support is supplied by capacitor banks at Otahuhu and Penrose, with dynamic reactive support provided by condensers at Otahuhu.

Demand-side management forms a substantial component of all scenarios in the Auckland region: 250MW by 2035, with the bulk occurring by 2025. The Sustainable Path scenario assumes a further 450MW of demand-side management by 2040. Thermal baseload generation expansion in Auckland is assumed to be significant in the Medium Renewables (over 400MW by 2030), Coal (over 1200MW by 2035) and High Gas Discovery (over 800MW by 2020) scenarios. In all scenarios a significant amount of peaking thermal generation is assumed to be built in the Auckland region, generally near or at Otahuhu, 200MW or more by 2030.

Projects recently completed, and scheduled to be completed during 2010, include:

- 200 MVAr capacitor bank at Otahuhu;
- 100 MVAr capacitor bank at Penrose;
- 220kV switching station at Drury to bus Huntly-Glenbrook-Otahuhu Line (completed project).

Substantial transmission augmentation is planned for this region including a new 400 kV capable transmission line, operated at 220kV, committed to be built from Whakamaru to Auckland (the new Brownhill transition station) by 2015. In all generation scenarios this line is assumed to continue to be operated at 220kV and is not upgraded to 400 kV before 2040.

Current projects likely to be completed by 2015 include:

- the conversion of Pakuranga from 110kV to 220kV, operation of the Otahuhu-Pakuranga line at 220kV and removal of the Pakuranga-Penrose 110kV line (committed project);
- thermal upgrading of Otahuhu-Whakamaru 220kV Line A and B (committed project);
- thermal upgrading of Otahuhu-Whakamaru 220kV Line C (committed project);
- removal of Arapuni-Pakuranga 110kV line to make way for 400 kV line (committed project);
- 400 kV line, operated at 220kV, Whakamaru-Brown Hill and 2x220kV cables Brown Hill-Pakuranga (committed project); and

- 220kV Pakuranga to Penrose cable, as per Transpower's North Auckland and Northland project.[77]

Depending on the generation scenario, there is a transmission opportunity for further augmentation between Pakuranga and Penrose, modelled as a second cable, before 2025 (South Island Wind and High Gas Discovery scenarios) or before 2030 (Sustainable Path, Medium Renewables and Coal scenarios).

There is a potential transmission opportunity for further 220/110kV interconnection capacity at Otahuhu by 2020, at Penrose by 2035 and at Hobson Street by 2035. Opportunities for additional transmission capacity are also possible between Otahuhu and Wiri, as are opportunities for operational measures between Otahuhu and Penrose, before 2020. By 2040, in the Coal scenario only, additional opportunities arise for managing congestion between Otahuhu and Penrose. Between Otahuhu and Wiri by 2035, opportunities for additional 110kV transmission capacity apply to the High Gas Discovery scenario. Operational measures between Otahuhu and Mangere arise by 2035, specifically for the Medium Renewables, Coal and High Gas Discovery scenarios.

Transmission opportunities into Bombay from Arapuni and Hamilton are discussed with the Waikato analysis.

Waikato

The Waikato regional demand is forecast to increase from around 590MW in 2010 to around 950MW by 2040.

The transmission network consists of 220kV and 110kV transmission lines with interconnecting transformers located at Hamilton. Substantial transmission from Whakamaru to Auckland passes through the region (upgrades to these circuits are described in the previous section). The 110kV network supplies demand in the region, branching out from both Hamilton and Arapuni.

The region offers over 2600MW of generation, including the Huntly gas- and coal-fired power station north of Hamilton. South of Hamilton, Karapiro and Arapuni provide generation on the 110kV network; further south, the Waipapa, Maraetai and Whakamaru hydro schemes provide generation on the 220kV network.

In all generation scenarios, at least 500MW of existing Huntly power station capacity is anticipated to be decommissioned by 2033, and as early as 2020 in the Sustainable Path scenario. All scenarios except the High Gas Discovery replace this decommissioned capacity with

77 http://www.electricitycommission.govt.nz/opdev/transmis/gup/naan

additional Huntly capacity spread across various technologies. Additionally, much of Huntly's generation capacity is modelled to be replaced by peaking plant in Auckland and significant amounts of geothermal generation built in the Wairakei region, with a minimum of 600MW modelled in all scenarios.

Aside from transmission into Auckland from the Waikato region, including the committed 400 kV capable Whakamaru to Pakuranga line initially operated at 220kV, there appear to be few additional transmission opportunities. There exists a transmission opportunity for additional interconnection capacity between the 220 and 110kV networks at Whakamaru by 2015, identified in all scenarios. Under the Sustainable Path scenario, which includes the early decommissioning of the Huntly power station, additional 220kV transmission capacity between Hamilton and Whakamaru is a possible transmission opportunity by 2030, as is reactive support at Waihou. Additional 110kV transmission capacity between Hamilton and Waihou is a transmission opportunity identified for all scenarios around 2035.

An opportunity for augmentation of 110kV transmission line capacity between Bombay, Hamilton and Arapuni, and between Arapuni, Hangatiki and Rangitoto Hills, may occur some time beyond 2015, dependent on the generation scenario and interim measures such as operational splits.

Wairakei

In terms of the North Island transmission system, the central Wairakei region is essentially a generating region with substantial peaking hydro and base load geothermal generation modelled in all scenarios. Power is exported to Hawke's Bay, the Bay of Plenty, Auckland and sometimes southward towards Bunnythorpe under certain generation/demand dispatch combinations.

There is a committed project to augment the 220kV Wairakei Ring (defined as the two parallel 220kV circuits Wairakei-Poihipi-Whakamaru and Wairakei-Ohakuri-Atiamuri-Whakamaru). There is a transmission opportunity to augment the Atiamuri to Ohakuri 220kV transmission capacity by 2040, in order to meet security criteria in the Sustainable Path, South Island Wind and High Gas Discovery scenarios. Operational measures such as intertripping may be sufficient initially (around 2025).

The combination of Huntly decommissioning and the significant amounts of geothermal generation that are assumed to be built (600MW build in the South Island Wind scenario by 2020 and over 700MW built in all other scenarios by around 2025) further increase the northward loading on the Wairakei Ring circuits.

Bay of Plenty

The Bay of Plenty regional peak demand is forecast to increase from around 460MW in 2010 to over 760MW by 2040.

The Bay of Plenty is supplied predominantly from the northern side of the Wairakei Ring by the 220kV Whakamaru-Atiamuri and Ohakuri-Wairakei circuits. 220kV transmission lines extend from Atiamuri hydro power station to Tarukenga and Ohakuri hydro power station to Kawerau and Edgecumbe where 220/110kV interconnecting transformers feed the 110kV network. A 110kV connection from Tarukenga also exists through Kinleith to Arapuni hydro power station in the Waikato region.

There is over 370MW of existing generation in the region, much of it embedded within the lower voltage network. All scenarios assume at least 100MW of diesel peaking plant by 2025. The Sustainable Path, Medium Renewables and Coal scenarios each assume that a further 125MW of geothermal is built by 2030. The Sustainable Path scenario has the greatest amount of additional generation with over 400MW added, with no particular source dominating. The High Gas Discovery scenario has the lowest additional generation with only the 100MW diesel peaking plant included.

Substantial transmission augmentation is planned for this region, the major augmentation being an upgrade of the 110kV Tarukenga-Kaitimako double circuit transmission line to 220kV (built at 220kV; presently operating at 110kV) and 220/110kV interconnecting transformers at Kaitimako substation (committed project) near Tauranga.

There are opportunities for increased transmission capacity of the 110kV lines between Rotorua and Tarukenga, modelled as a thermal upgrade. Opportunities for increased transmission capacity of the 110kV lines between Kaitimako, Mt Maunganui and Poike are also identified. Additionally, opportunities exist for augmentation, potentially via reconductoring, of the Kinleith-Lichfield-Tarukenga 110kV circuits. All scenarios yield opportunities for operational measures managing constraints on the 110kV lines between Edgecumbe and Kawerau.

Hawke's Bay

The Hawke's Bay regional demand is forecast to increase from around 280MW in 2010 to 390MW by 2040.

Hawke's Bay is supplied from Wairakei by a double circuit 220kV transmission line. Two 110kV circuits also connect Hawke's Bay from Bunnythorpe through Woodville-Dannevirke-Waipawa to Fernhill but these are usually open at Waipawa.

The region has over 160MW of generation capacity (excluding the 155MW Whirinaki generation station used for dry years or as otherwise determined by the Commission; all scenarios include the decommissioning of Whirinaki by 2030). The majority of this generation is from the Waikaremoana hydro scheme which consists of three stations: Tuai, Kaitawa and Piripaua.

The Sustainable Path and South Island Wind scenarios assume up to 290MW of wind generation (the proposed Titiokura, Mokairau and Te Pohue wind farms) and up to 80MW of run-of-river hydro generation are added by 2025; the Medium Renewables scenario includes some of the wind generation but pushes the completion date out to 2040. With the exception of the Coal scenario, which assumes no new generation, all scenarios assume a 100MW diesel peaking plant by 2020 (2040 in the High Gas Discovery scenario). The Sustainable Path, South Island Wind and Medium Renewables share up to 90MW of further diesel peaking plant by 2040.

A transmission opportunity for additional reactive support at Gisborne was identified. This opportunity is specific to the South Island Wind scenario by 2020 and the Coal scenario by 2040. The PSA found a further opportunity for additional 110kV Gisborne – Tuai transmission capacity around 2030 and additional 220/110kV interconnection capacity at Redclyffe by 2035.

Central North Island

The Central North Island regional demand is forecast to increase from around 335MW in 2010 to 465MW by 2040.

The region comprises 220kV and 110kV transmission lines with interconnecting transformers at Bunnythorpe. One double circuit and two single circuit 220kV transmission lines connect Bunnythorpe to Haywards. The loading on these circuits depends on demand in Wellington and HVDC transfer. Transmission north of Bunnythorpe consists of three single circuit 220kV transmission lines, two connecting to Whakamaru via Tokaanu. The third connects Bunnythorpe to Wairakei via Tangiwai and Rangipo. A double circuit 220kV line connects Stratford with Bunnythorpe via Brunswick.

The Manawatu has plentiful wind possibilities; some of this existing and embedded in the low voltage network. All scenarios include the Te Rere Hau 4 wind farm, due for commissioning in 2011. The Sustainable Path, South Island Wind and Medium Renewables scenarios all assume a further 100 to 410MW of additional wind generation is installed by 2033. The Sustainable Path, South Island Wind, Medium Renewables and High Gas Discovery scenarios assume up to 110MW of additional run-of-river hydro built by 2035. In the Central North Island region, the South Island Wind scenario offers around 595MW of additional generation capacity by 2040 while the Coal scenario offers only a 15MW wind farm commissioned in 2011.

Opportunities for additional 220/110kV interconnection capacity at Bunnythorpe were identified, as were opportunities for operational measures altering the 110kV network in the Woodville – Mangamaire area. Beyond 2025, opportunities were identified in several scenarios for additional 220kV transmission line capacity between Bunnythorpe and the Central North Island. Additional dynamic reactive support at Bunnythorpe and transmission capacity between Bunnythorpe and Brunswick were identified as transmission opportunities in the same period for the Coal and High Gas Discovery scenarios only. By 2040, for the Coal scenario only, additional 110kV transmission capacity between Bunnythorpe and Woodville was identified as a further opportunity.

Taranaki

Taranaki is characterised as a thermal generation region with relatively low demand. The SOO demand forecast for this region is for an increase from 145MW in 2010 to 180MW in 2040.

The generation in the area is dominated by the 360MW TCC plant. Other significant generation within the region is a 70MW co-generation plant at Whareroa and a 30MW hydro scheme at Patea. A 200MW peaking gas turbine is due for commissioning in 2010.

In the Sustainable Path, Medium Renewables, Coal and High Gas Discovery scenarios the Taranaki 380MW CCGT at Stratford is assumed to be decommissioned by 2025. The Sustainable Path scenario includes approximately 250MW of additional generation by 2035, spread across wind, wave and diesel technologies. The South Island Wind scenario adds 350MW of primarily gas and diesel generation by 2035. The Medium Renewables scenario adds 400MW of primarily gas and diesel generation by 2040. The Coal scenario adds around 900MW of gas generation by 2040; the High Gas Discovery scenario doubles that figure to around 1800MW. Both the Coal and High Gas Discovery scenarios include replacements for the Taranaki 380MW CCGT built by 2033. The Sustainable Path scenario assumes 110MW of wind generation is built by 2028.

The PSA identified limited transmission opportunities in Taranaki. In particular, transmission capacity increases between Stratford, Brunswick and Bunnythorpe were identified as opportunities around 2030 for the Coal and High Gas Discovery scenarios. By 2040, additional 220/110kV interconnection capacity at Stratford was identified as a transmission opportunity in the same scenarios.

Wellington

The Wellington regional demand is forecast to increase from around 690MW in 2010 to 1110MW by 2040.

The transmission network comprises 220kV transmission lines connecting Haywards to Bunnythorpe in the north and a 110kV transmission line through the Wairarapa. Interconnecting transformers are located at Haywards and Wilton. The HVDC link terminates at Haywards substation from Benmore Power station in the South Island.

In December 2007 Transpower announced it would decommission half of the HVDC link Pole 1 after standing down the full Pole 1 in September 2007. Pole 1 was located on the 110kV network and helped support the local Wellington demand. Before the stand-down, Transpower up-rated some of the 110kV transmission lines, which provided additional security. A Pole 1 replacement, designated Pole 3, is under construction and due for commissioning in 2012.

The region is essentially a major demand area with very little local generation. However, with good wind potential there is a high likelihood of future increased wind generation. This was initiated with the commissioning of Meridian's West Wind project, a 144MW wind farm, the largest in the Wellington area. The Sustainable Path and South Island Wind scenarios assume over 300MW of additional wind generation is installed by 2035, while the Medium Renewables scenario assumes 120MW is installed by 2025 with a further 90MW by 2040. The Coal scenario includes 120MW of wind generation by 2040.

There are opportunities for augmenting the interconnection capacity between the 220kV and 110kV networks. The replacement of the Wilton 220/110kV interconnecting transformer has recently been completed. An opportunity for an additional 220/110kV interconnecting transformer arises at Haywards before 2025, in the Coal and High Gas Discovery scenarios. With increased demand growth in the region there are opportunities for 110kV network augmentation, including voltage support north of Wellington. Opportunities for 110kV operational measures, specifically closing the Mangahao to Paraparaumu splits and opening a Mangamaire to Woodville split, are also present, and may resolve overload issues, at least initially. However, around 2025, an opportunity arises for a transmission capacity upgrade, between Takapu Road and Pauatahanui, to supply the regional demand north of Wellington. Also around 2025, in all scenarios except the Sustainable Path, an opportunity for augmentation of the transmission capacity between Haywards and Melling was identified and modelled as reconductoring.

Further opportunities identified include an upgrade of protection equipment associated with the Haywards to Gracefield 110kV circuit (Sustainable Path and South Island Wind scenarios only, around 2030), reactive support at Central Park (all scenarios except Sustainable Path, around 2025) and reactive support at Paraparaumu (by 2015).

South Island transmission analysis

Nelson/Marlborough

The Nelson/Marlborough demand is forecast to increase from around 230MW in 2010 to around 325MW in 2040.

The top of the South Island consists of the Nelson/Marlborough and West Coast regions and is supplied from Islington in Christchurch to Kikiwa substation by three 220kV circuits on two transmission lines. The Nelson/Marlborough transmission network consists of a parallel network of 220kV and 110kV transmission lines between Kikiwa and Stoke with a 66kV spur supplying the Golden Bay area. There are also 220/110kV interconnecting transformers at Kikiwa and Stoke.

The main generators in the region are the 32MW Cobb power station in Golden Bay, and the 11MW Branch River scheme in the Wairau valley. Future generation modelled in the region is a new 73MW Wairau scheme included in all scenarios, a new 85MW Mohikinui scheme which is built in both the Sustainable Path and High Gas Discovery scenarios, and 43MW of the Mohikinui scheme built in the South Island Wind scenario. The Sustainable Path scenario includes an additional suite of solar, run-of-river hydro and biomass co-generation built after 2025.

The relatively low demand growth, coupled with the recent transmission upgrades in the region – including a +/- 40 MVAr STATCOM located at Kikiwa substation completed by Transpower in 2010 – means that minimal transmission opportunities were identified in any of the generation scenarios throughout the duration of the analysis. There is, however, an opportunity around 2035 for an increase in 110kV transmission capacity between Kikiwa and Stoke.

West Coast

The West Coast regional demand is forecast to increase from around 60MW in 2010 to 89MW by 2040. The Lower West Coast demand is forecast to increase reasonably significantly in the next few years, driven mainly by the mining sector.

The West Coast is predominantly supplied from Kikiwa substation through a 220/110kV interconnecting transformer and two 66kV circuits from Lake Coleridge. From the 110kV Inangahua substation, two transmission lines supply the Northern West Coast/Buller region with another two 110kV lines supplying Reefton. From Reefton a single circuit 110kV line supplies Dobson with a new GXP added for the Pike River Coal mine near Atarau. A committed project for the addition of a second transmission line from Reefton to Dobson with a second 110/66kV interconnecting transformer at Dobson and capacitors at Hokitika is nearing completion and will provide additional security to the new Atarau GXP and the Lower West Coast.

The Northern West Coast has very little generation. However, the Lower West Coast south of Dobson has significant embedded generation in the form of a number of small hydro plants, the largest being the Kumara/Dillmans scheme of around 10MW.

Only the Sustainable Path and South Island Wind scenarios have increased hydro generation. A 46MW scheme at Arnold, built by 2020, is common to both scenarios; a 25MW scheme at Toaroha is also common but with substantially different build dates. The Sustainable Path scenario includes 38MW of wave generation and a further 33MW of hydro, both to be built after 2025.

The only transmission opportunity identified was an increase in 110kV transmission capacity between Inangahua and Kikiwa, by 2040.

Canterbury

The Canterbury regional demand is forecast to increase from around 820MW in 2010 to over 1340MW by 2040.

The region is supplied from the Waitaki valley by four main 220kV transmission circuits: three from Twizel and one from Livingstone. These circuits supply the Upper South Island (USI), consisting of the Nelson/Marlborough region, the West Coast, and Canterbury regions. The transmission network within Canterbury comprises 220kV and 66kV transmission circuits, with 220/66kV interconnections at Islington, Bromley, Culverden and Waipara. As demand increases in the USI, voltage stability limits constrain the transmission into Christchurch and the USI. Several recently completed projects assist to relieve the voltage stability limits into Christchurch, specifically:

- bussing the 220kV Islington-Twizel circuits at Ashburton (completed project);
- 75 MVAr capacitor at Islington (completed project); and
- -75/+100 MVAr SVC at Islington (completed project).

Around 2025 and later, opportunities remain for additional 220kV transmission capacity and further dynamic reactive support to provide transmission support for the Upper South Island.

The analysis identifies opportunities for additional 220/66kV interconnecting capacity at both Bromley and Springston by 2015, and again at Bromley by 2035, as well as additional 66kV capacity in the Christchurch area around 2025, with scope for operational measures initially.

An opportunity exists for further 220/66kV interconnecting capacity at Islington by 2035.

South Canterbury

The South Canterbury regional demand is forecast to increase from around 100MW in 2010 to 160MW by 2040.

This region contributes a major portion of the generation in the South Island through the Tekapo, Ohau and Waitaki Valley generation stations. The main transmission system is designed to export power to the major demand areas such as the upper South Island and the North Island through the HVDC link. The region supplies its small demand through 220/110kV interconnecting transformers at Timaru and Waitaki. Outside of the peak dairy season, the 110kV network is normally split at Studholme, creating two radial feeds supplying Temuka, Albury and Tekapo from the Timaru interconnection, and Studholme, Black Point, Bells Pond and Oamaru from the Waitaki interconnection.

All five scenarios include 85MW of new peaking hydro at Waitaki by 2015. All but the High Gas Discovery scenario include a further 280MW hydro plant with varying build dates.

Around 2030, transmission opportunities are identified in the form of additional 220kV transmission capacity between Benmore and Ashburton, to provide support to the Upper South Island. At Timaru, an opportunity for increased transmission capacity, including interconnection capacity, is identified by 2030. Opportunities for reactive support at Oamaru are also identified by 2015.

Otago/Southland

The Otago/Southland regional demand is forecast to increase from around 1150MW in 2010 to around 1320MW by 2040 in the Sustainable Path, South Island Wind, Coal and High Gas Discovery scenarios. In the Medium Renewables scenario, the 600MW Tiwai Point aluminium smelter is assumed to be decommissioned in stages between 2022 and 2027. This causes the demand in the region to approximately halve from around 1250MW in 2020 to around 670MW in 2030.

The transmission network consists of 220kV and 110kV transmission lines with interconnecting transformers at Cromwell, Halfway Bush, Roxburgh and Invercargill. Transmission out of the region during low-demand, high-generation dispatch is limited by the transmission capacity north of Roxburgh. This inter-regional constraint may become binding if high levels of generation are built in the Southland region and/or the Tiwai Point Aluminium smelter is decommissioned.

Along with the existing large hydro stations at Manapouri, Clyde, and Roxburgh, high levels of additional generation are modelled in the Sustainable Path, South Island Wind and Coal scenarios. The Sustainable Path and South Island Wind scenarios share significant amounts of new wind generation—over 1300MW by 2040 in both and over 1000MW by 2015 in the South Island Wind scenario. The Sustainable Path scenario includes over 500MW of hydro generation on the Clutha by around 2025. The Medium Renewables and High Gas Discovery scenarios offer the least new generation. The Coal scenario includes a 400MW lignite fired coal plant by 2025.

The PSA identified potentially binding constraints on the Lower South Island transmission circuits during peak demand periods under contingent conditions. Transmission upgrades in this region are dependent on the generation dispatch and are therefore likely to be economic, rather than reliability driven investments.

Under all scenarios, a transmission opportunity was identified for additional voltage support at Frankton/Queenstown by 2015. The 400MW Edendale lignite generation plant included in the Coal scenario yields a transmission opportunity for a 220/110kV interconnection at Edendale before 2025, modelled as a link from the existing North Makarewa to Three Mile Hill circuits. A transmission opportunity was identified around 2020 for additional interconnection capacity at Roxburgh. In the High Gas Discovery scenario, which included no generation in the Hawea area, a transmission opportunity was identified by 2035 for additional interconnection capacity at Cromwell. Further opportunities for operational measures involving closing (under transformer overload conditions at Roxburgh) the 33 kV bus split at Halfway Bush were identified in all scenarios.

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