The Future of Electricity Generation in New Zealand

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Abstract

Increasing demand for electricity in New Zealand requires approximately 150 megawatts of new capacity to be installed annually. Rapidly increasing global prices for fossil fuels; the New Zealand Energy Strategy with its focus on renewable technologies; climate change policies; and a gradual shift from an energy constrained electricity system to one with capacity constraints are all factors underlying a change in the type of generation plant being installed and the location of that plant. This paper examines the likely future of the generation sector over the next 20-30 years. It is based on the work undertaken by the Electricity Commission in preparing its Statement of Opportunities, which contains scenarios describing how electricity may be generated in the future. These scenarios are produced using the Commission's generation expansion model.

Key words: Electricity, capacity expansion.

Introduction

As part of its role in overseeing aspects of transmission investment, the Electricity Commission (Commission) must prepare and publish a Statement of Opportunities (SOO). The purpose of the SOO is to enable the identification of potential opportunities for efficient management of the grid, including investment in upgrades and transmission alternatives. The 2008 SOO is nearing completion and is currently available in draft form, Electricity Commission (2008).

In order to evaluate grid investment proposals, it is necessary to form a view as to the likely future development of the electricity sector with respect to demand for electricity and the expansion of generation capacity. These and other assumptions are referred to as the Grid Planning Assumptions (GPAs), and are published in the SOO. In order to reflect the inherent uncertainty associated with predicting future demand and capacity expansion, a scenario approach is used to develop the GPAs.

This paper focuses solely on the generation capacity expansion aspect of the GPAs. The key drivers of future generation technologies are identified and the process by which the scenarios are developed is briefly explained. A summary of capacity expansion by region and technology is given for each of five scenarios. This paper draws heavily on the draft 2008 SOO and further information, including detailed plant-by-plant expansion plans can be found in the draft 2008 SOO. CO_2-equivalent emissions, and capital and operating costs are also presented.

A secondary purpose of the paper is to explain the rules and processes around grid investment and the respective roles of the Commission and Transpower. To that end, the paper proceeds by briefly describing the regulatory backdrop to transmission investment.

Regulatory and Policy Context

Introduction

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

The Commission's principal objectives, as set out in the Act, are to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner, and to promote and facilitate the efficient use of electricity.[1] The Commission must have the objectives and the specific outcomes listed in section 172N of the Act in mind in exercising its powers. The Act also sets out a number of specific functions of the Commission, including to:

- administer the Electricity Governance Regulations (Regulations) and the Electricity Governance Rules (Rules), (section 172O(1)(b)); and
- give effect to Government Policy Statement (GPS) objectives and outcomes (section 172O(1)(j)).

In relation to transmission, part F of the Rules sets out a series of processes that the Commission must follow to produce comprehensive transmission pricing, transmission contracting, transmission investment arrangements, and interconnection services.

Section III of part F sets out rules relating to grid upgrades and investments.[2] It is under section III that the Commission is required to prepare and publish the SOO.

Rule 2 sets out the purposes of the rules in section III of part F as being to:

2.1 facilitate Transpower's ability to develop and implement long-term plans (including timely securing of land access and resource consents) for investment in the grid;

2.2 assist participants to identify and evaluate investments in transmission alternatives;

2.3 facilitate efficient investment in generation;

2.4 facilitate any processes pursuant to Part 4A of the Commerce Act 1986; and

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1 Section 172 N(1).

2 Unless stated otherwise, each reference in this paper to a rule is to a rule in section III of part F of the Rules.

2.5 enable the cost of approved investments to be recovered through the transmission pricing methodology applied in transmission agreements.

In summary, the Rules seek to facilitate timely investment in transmission infrastructure in an efficient and cost-effective way.

Respective roles of the Commission and Transpower

The Commission and Transpower each have distinct roles and obligations in relation to transmission planning and investment under section III of part F. These different roles are:

- The Commission is responsible for:
    - preparing and publishing key information, such as the SOO, including the Grid Planning Assumptions (GPAs) and the centralised dataset (CDS);
    - determining the Grid Reliability Standards (GRS) that the grid must meet over time, and the Grid Investment Test (GIT) against which Transpower's investments will be assessed; and
    - considering and, if appropriate, approving investments proposed by Transpower in a Grid Upgrade Plan (GUP).
- Transpower is responsible for:
    - developing and maintaining the transmission grid and operating the grid assets;
    - reporting on the forecast ability of the grid to meet the GRS, the Grid Reliability Report (GRR), and on economic investments that could be made to interconnection assets, the Grid Economic Investment Report (GEIR); and
    - grid planning to meet the GRS, including preparing GUPs for proposed investments in the grid.

In summary, the Commission's role is to provide information, review and approve investments in a GUP that meet the criteria set out in the Rules, and reject investments that do not. Transpower is responsible for grid planning, development and operation.

Recognising the interface between their respective roles, the Commission and Transpower have jointly developed a grid upgrade investment and review policy (GUIRP). Its purpose is to promote an effective process for the preparation of investment proposals by Transpower, as part of Transpower's wider grid planning process, and the review of those proposals by the Commission. It provides a framework within which the Commission and Transpower will interact during the grid upgrade and investment and review process, and provides guidance to interested parties in relation to how Transpower and the Commission will interact with them.[3]

The Commission's intention is to publish the SOO by the first working day of October every second year. Publication at that time allows Transpower six-months to publish the GRR and GEIR. Accordingly, Transpower intends to publish an Annual Planning Report (APR) containing those reports by 31 March each year. The six-

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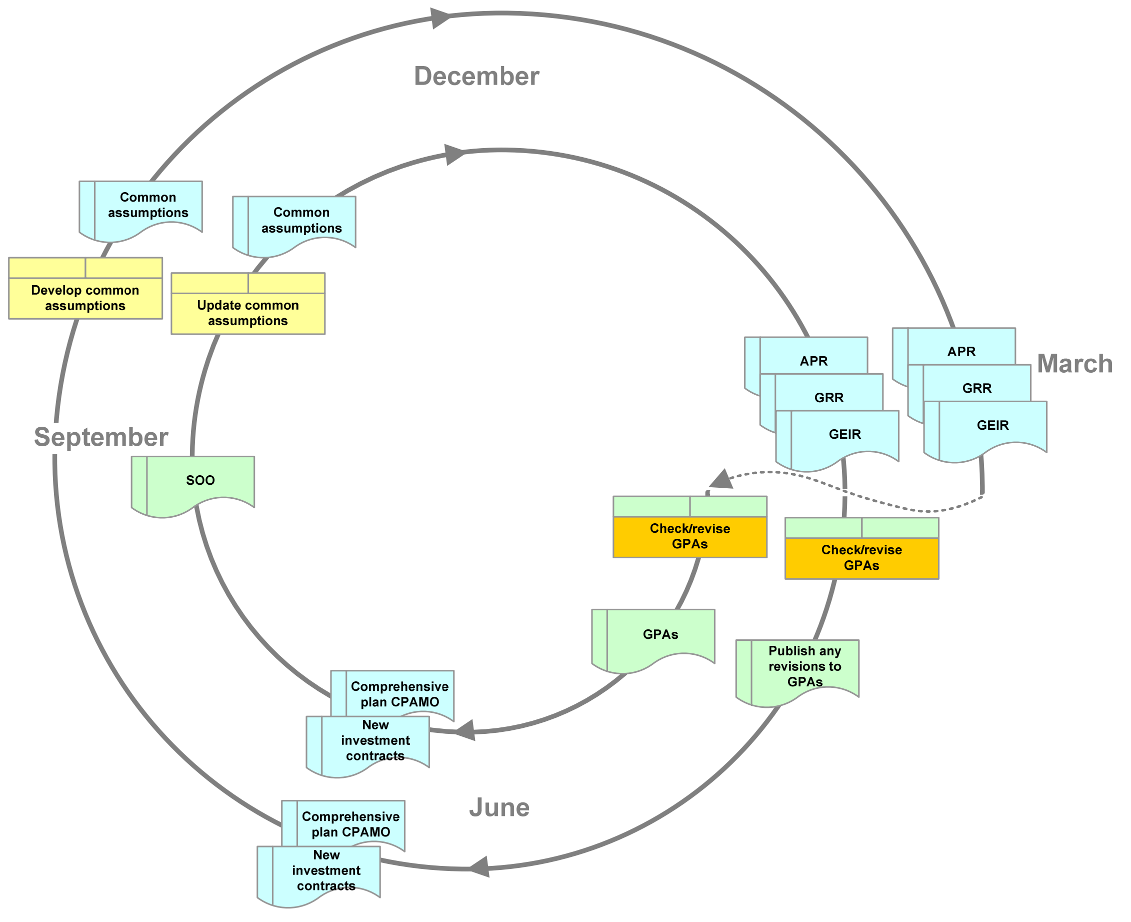
[3] http://www.electricitycommission.govt.nz/opdev/transmis/gridupgradepolicy.

month period aligns with Transpower's obligations under the Rules in relation to publishing the GRR and GEIR.

As new information may come to light in the period after a SOO is published, it might be necessary for the Commission to consider, as provided for in clause 6.1 of the GIT, whether scenarios other than the scenarios set out in the SOO are more appropriate for the purposes of applying the GIT to a particular investment proposal. In addition, some proposals may require more specific scenarios than those provided in the SOO. If this is the case, Transpower, the Commission, or a proponent of a transmission alternative, may put forward such alternative scenarios.

The grid planning process is illustrated in Figure 1.

Figure 1 Biennial grid planning cycle



Development of Generation Scenarios

This section describes the Commission's approach to scenario development for the 2008 SOO and provides a brief description of the five generation scenarios. This section also includes a discussion of how the scenario approach within the SOO will have a bearing on scenario evaluation under the GIT, plus a brief discussion of GEM (generation expansion model), the Commission's purpose-built scenario development tool.

Approach to scenario development

Overview

The GPAs are required to contain, among other things, 'committed projects for additional generation…'[4] and 'a reasonable range of credible future, high-level generation scenarios…'[5].

The committed generation projects and future generation scenarios inform the market and support industry transmission planning processes.

- They form part of the GPAs that feed into the scenarios set out in the SOO and are the default Market Development Scenarios (MDSs) used in applying the GIT to grid investment proposals put forward by Transpower (in a GUP).
- They provide stakeholders who may wish to undertake their own analyses with a reasonable range of credible future scenarios.

Scenario techniques are typically adopted where 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 is 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.

- Assembling 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.
- Developing the scenario 'stories'—that is, identifying the key drivers and assumptions (for example fuel cost and availability, discount rates, carbon price) which guide the future development paths in the scenarios, and determining which internally consistent combination of drivers will apply in each scenario.
- Running the models to develop each generation scenario.

This process is illustrated in Figure 2.

It should be noted that the modelling approach is not output-driven. That is, the input assumptions have not been chosen to deliver a pre-determined outcome (such as a certain quantity of generation capacity to be built at a particular time and location). Rather, the Commission has used an internally consistent 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.

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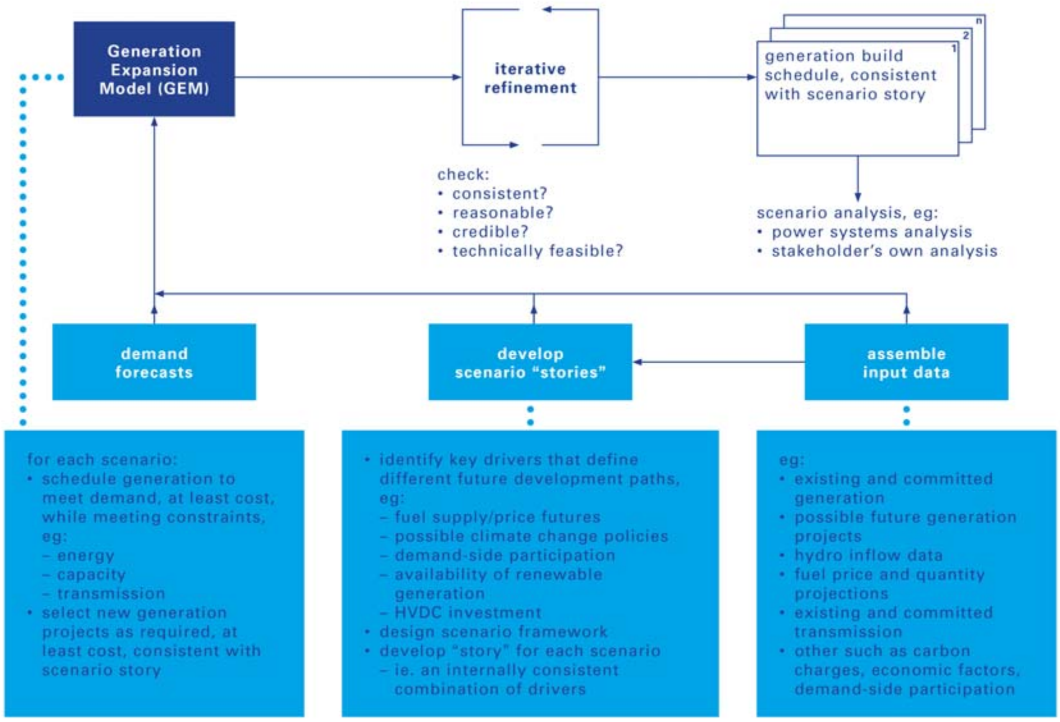
[4] Rule 10.3.1.1 of section III of part F.

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

Figure 2 Scenario development process



These steps are repeated, in a process of iterative refinement, until the scenarios are reasonable, credible, technically feasible, suitable for power systems analysis, and accurately reflect the stories that they are intended to depict.

Stakeholders can reproduce the scenarios by downloading the GEM model and running it to generate build schedules.[6] This allows interested parties to investigate the effects of varying any assumption on the end result. The Commission views this as a step forward from the Initial SOO, prepared in 2005, where the scenario development could not easily be reproduced.

The current approach, as described in the GUIRP, also provides greater flexibility to Transpower to modify the scenarios, as a result of its own consultation during the process of preparing investment proposals, and to do so in a way that is transparent and able to be replicated by the Commission or other stakeholders.

Reviewing inputs, assumptions, and scenario framework

The Commission prepared and published a set of information on committed and possible future generation projects in 2007 and early 2008 in the lead up to its preparation of the 2008 SOO. The information was compiled following discussions

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

with stakeholders and consideration of specialist reports commissioned from generation experts.[7]

In particular, the Commission:

- updated input data in response to announcements by participants and reviewed a number of industry publications such as annual reports and energy outlook papers;
- updated its centralised dataset[8] which contains factual and historical information on the transmission system, nodal prices, bids and offers, demand and generation information;
- held discussions with stakeholders to explore possible future generating projects, fuel supply and cost projections, major maintenance programmes and other relevant information;
- drew on data from reports commissioned for the transmission to enable renewables (TTER)[9] project including hydro, wind and geothermal; and
- engaged a consultant to provide information on the potential marine (wave and tidal) generation worldwide and more specifically in New Zealand.

Developing the scenario 'stories'

In preparing to develop a set of scenario stories, the Commission:

- reviewed experience from the Initial SOO and from recent consideration of investment proposals put forward by Transpower;
- reviewed the approach adopted by other parties in developing a scenario framework and/or development methodology (for instance, MED, Solid Energy);
- explored possible modelling methodologies and scenario development techniques;
- considered the energy policy context, likely drivers of future supply and demand and key uncertainties; and
- engaged with a representative set of stakeholders to seek input into identifying key uncertainties and designing the scenario framework.

The output from these reviews formed the basis for the Commission's preparation for the 2008 SOO scenario development process.

The Commission settled upon 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, fate of existing thermal stations, fuel availability and cost, state of the HVDC link, 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:

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7 See http://www.electricitycommission.govt.nz/opdev/modelling/gpas/index.html.

8 See http://www.electricitycommission.govt.nz/opdev/modelling/centraliseddata/index.html.

9 See http://www.electricitycommission.govt.nz/opdev/transmis/renewables.

- uncertain;
- very 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 (that is, thermal stations are more likely to be displaced by renewables if fuel prices and carbon prices are high). 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.

Generation Expansion Model (GEM) overview

The Commission's generation expansion model is a long-term capacity planning model. The key purpose of GEM 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 then, GEM has been further developed in a number of areas related to model implementation and system representation. A number of possible further developments have been identified, and the Commission intends progressively working through these over time.[10]

Technically speaking, the heart of GEM is the canonical capacity expansion problem formulated as a mixed integer programming (MIP) problem. The computer code is written using the GAMS optimisation software and the model is solved with CPLEX, a commercial MIP solver accessed via the GAMS/CPLEX 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 GPAs includes the following key features.

- The costs the model seeks to minimise include capital expenditure for new generation plant and transmission investments, fixed and variable operating costs for all generation plant, and HVDC charges (where variable costs include operating and maintenance costs, carbon charges, fuel costs, and, where applicable, carbon sequestration costs).

[10] The GEM computer codes, as used for this 2008 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.

- 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 linked are modelled explicitly, as are transmission losses on the HVDC link.
- Annual energy demand is modelled using nine-block quarterly load duration curves (LDCs).
- Peak demand in each island is modelled with an instantaneous ‘capacity constraint’ requirement in each year, which must be satisfied by committed and new projects given their assumed availability at peak.
- The 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).
- Capacity expansion plans (build schedules) are determined according to the weighted average system operation costs over five representative hydro inflow sequences.
- Upgrades to the HVDC link are assumed to occur in 2012 and 2018.
- Perfect competition in the wholesale electricity market is assumed (that is possible wholesale or retail market competition benefits from transmission investments are not currently considered).
- Ancillary services are not completely represented in GEM as configured for preparation of the 2008 SOO. While some of these services are modelled within the context of the capacity constraints, the energy side of the model ignores ancillary services. A comprehensive treatment of a range of ancillary services in GEM has since been developed.

Scenario outline and weightings

Scenario outline

A brief description of each of the scenarios is included in Table 1. These form the core of the supply-side of the GPAs.

Renewableness

In the context of the New Zealand Energy Strategy (NZES), a key output statistic is the projected proportion of electricity that would be produced by renewable generation. Renewable generation fuels are deemed to include hydro, geothermal, wind, biomass, and marine, but not gas, coal or diesel. The exception is that coal or gas with carbon sequestration is considered to be renewable (because the greenhouse emissions would be relatively low). The five scenarios vary in the extent of renewable generation attained.

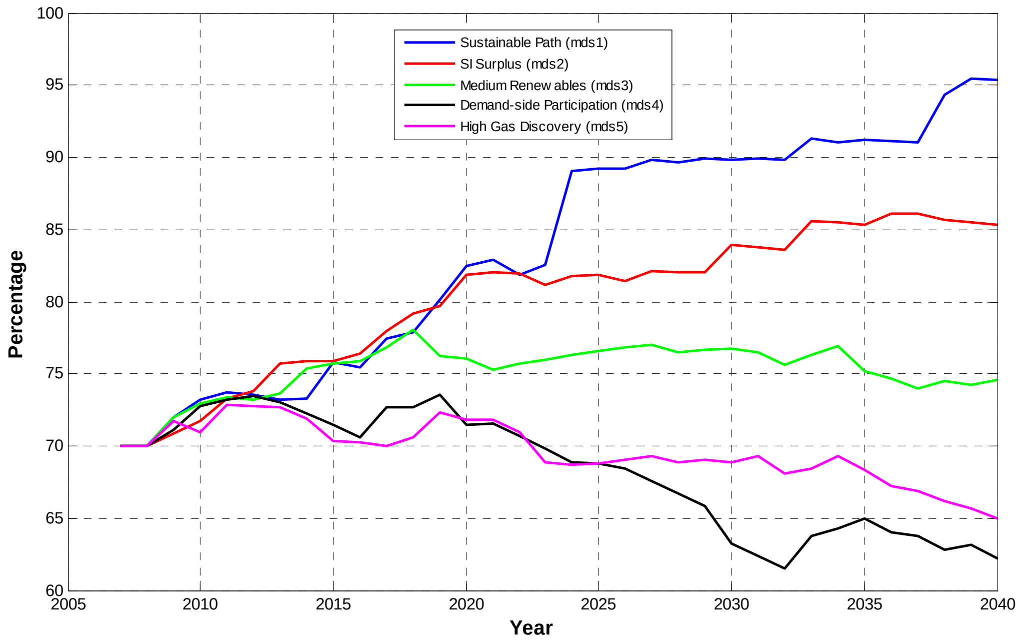
- Sustainable Path is 89 percent renewable by 2025.
- South Island Surplus is about 82 percent renewable by 2025.
- Medium Renewables is about 77 percent renewable by 2025.
- Demand-side Participation is about 69 percent renewable by 2025.

- High Gas Discovery is approximately 69 percent renewable by 2025.

Table 1 Scenario outlines

Sustainable Path	New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020. New energy sources are brought on stream in the late 2020s and 2030s, including biomass, marine, and carbon capture and storage. Demand-side response helps to manage peak demand.
South Island Surplus	Renewable development proceeds at a slightly more moderate pace, with all existing gas-fired power stations remaining in operation until after 2030, though taking a more mid-order role as gas prices increase. The coal-fired units at Huntly Power Station are shifted into a reserve role and eventually removed from service. Wind and hydro generation increase considerably, particularly in the lower South Island. Relatively little geothermal energy is utilised. Thermal peakers supplement renewable development.
Medium Renewables	A ‘middle-of-the-road’ scenario. Renewables are developed in both islands, with North Island geothermal development playing an important role. The coal-fired units at Huntly transition through dry-year reserve to total closure. Thermal peakers and a new CCGT supplement renewable development. Tiwai smelter is assumed to decommission in the mid-2020s.
Demand-side Participation	Demand-side participation becomes a more important feature of the market, driven by a desire from consumers of all types to become more involved. Electric vehicle uptake is high, and vehicle-to-grid technology is used to manage peaks and provide ancillary services. On the generation side, new coal- and lignite-fired plants are constructed after 2020, and geothermal resources are developed. Little new hydro can be consented, however, and some existing hydro schemes have to reduce their output (due to difficulty in securing water rights). Huntly Power Station remains in full operation until 2030. Electricity-sector emissions rise, though transport-sector emissions would be lower than in other scenarios
High Gas Discovery	Major new indigenous gas discoveries keep gas prices low to 2030 and beyond. 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.

Figure 3 Renewable energy share by scenario



Scenario weighting

With regard to the relative weightings accorded to the scenarios, it is essentially academic, as their use within the SOO is solely to help stakeholders understand the range of possible futures. However, their use within the GIT is material.

Accordingly, the Commission has given careful consideration to the weightings of the scenarios for the 2008 SOO. It has considered experience from the Initial SOO, feedback from submitters in the earlier GPAs consultation, and further development work. The Commission has also been mindful of recent policy announcements from Government, particularly the NZES. At this stage, the Commission's view is that the five scenarios should all be assigned equal weight.

Scenario linkages with the Grid Investment Test (GIT)

With respect to the use of the SOO scenarios in the application of the GIT, it is the Commission's view that an a priori scenario approach will not always be the best means of evaluating a transmission investment.

In constructing scenarios for the SOO, there are many 'degrees of freedom' in selecting assumptions and modelled plant. In particular there are many different possible combinations of internally consistent input assumptions. Using a limited set of scenarios is an appropriate approach for the SOO in terms of helping inform stakeholders of the broad range of possible futures and the general impact of key drivers.

However, for the GIT analysis of a major transmission investment, the outcome of an economic analysis of the transmission proposal using the SOO scenarios could be materially different to one which considered a more tailored set of possible futures having regard to the particular investment proposal.

Therefore, in accordance with clause 6.1 of the GIT, the Commission may determine that market development scenarios proposed by Transpower, the proponent of a transmission alternative, or the Commission are more appropriate. This enables the Commission to adopt alternative scenarios that more reasonably reflect new information in light of the investment proposal in front of it.

The Rules also permit a real options analysis of benefits to be adopted, as an alternative to a standard net present value analysis. Current practice for evaluating real options value for transmission investments using a standard net present value analysis is to employ a Monte Carlo simulation of many possible futures (many thousands to millions). To make this problem numerically tractable, many simplifications must be made to modelled interactions (for example to avoid the need for power flow analysis within each Monte Carlo draw). A hybrid approach, utilising both scenarios and Monte Carlo real options analysis was developed for the recent analysis and decision on Transpower's North Island GUP.

There is considerable flexibility within the Rules to vary scenarios and use state of the art analysis techniques, where there is merit in doing so. This would principally be for large investments. In other cases, a simple application of the existing scenarios will be appropriate. It is the Commission's view that establishing the default scenarios in the SOO, but allowing the Commission to adopt other scenarios if it considers appropriate, best balances the need to provide a flexible environment within which Transpower can undertake the cost benefit analysis required by the GIT, with the need for a transparent framework for transmission investment decision-making.

Generation Scenarios

Introduction and overview

This section describes the five generation scenarios developed by the Commission resulting from the application of the assumptions summarised above and described in greater detail in the draft 2008 SOO. Much greater detail than is presented below about each scenario can be obtained from the draft 2008 SOO.

Each scenario is defined by a schedule of new generation projects on a timeline from 2008 to 2040; that is, lists of projects to be constructed, by commissioning year including generator decommissioning.

Although the results and commentary in this section extend to 2040, it should be recognised that predicting generation over such a long timeframe is fraught with difficulties. Readers should view the Commission's predictions with a degree of scepticism proportional to the gap between now and the year of the predicted event. Even predictions to 2015 are affected by many uncertainties around policy settings, fuel prices, resource availability, and technological costs; but projections beyond 2030 are attempting to describe a world in which our economy, society, environment, and technological options might be very different.

It is important to emphasise that the generation projects included in each scenario should 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 somehow more technically desirable, 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 2 Net capacity installed and retired by region, MW

	Sustainable Path	South Island Surplus	Medium Renewables	Demand-side Participation	High Gas Discovery
Northland	655	1,070	100	420	720
North Shore	0	0	0	0	480
Auckland	698	1,882	1,732	2,032	1,832
Bay of Plenty	314	120	232	532	157
Waikato	1,892	694	348	248	-372
Rangitikei	554	409	339	279	259
Hawke's Bay	545	193	270	102	0
Taranaki	460	-150	730	-160	680
Wellington	613	583	213	863	263
Nelson/Marlborough	73	0	73	73	73
Christchurch	255	100	0	200	500
West Coast	263	50	50	50	50
Otago	1,367	1,207	202	722	285
Southland	97	17	17	417	17
Total	**7,785**	**6,175**	**4,306**	**5,778**	**4,944**

Installed capacity and energy produced by scenario

Sustainable Path scenario

Figure 4 and Figure 5 show the installed capacity and the energy stackplots by technology and by year for the Sustainable Path scenario.

Figure 4 Installed capacity by technology, Sustainable Path scenario

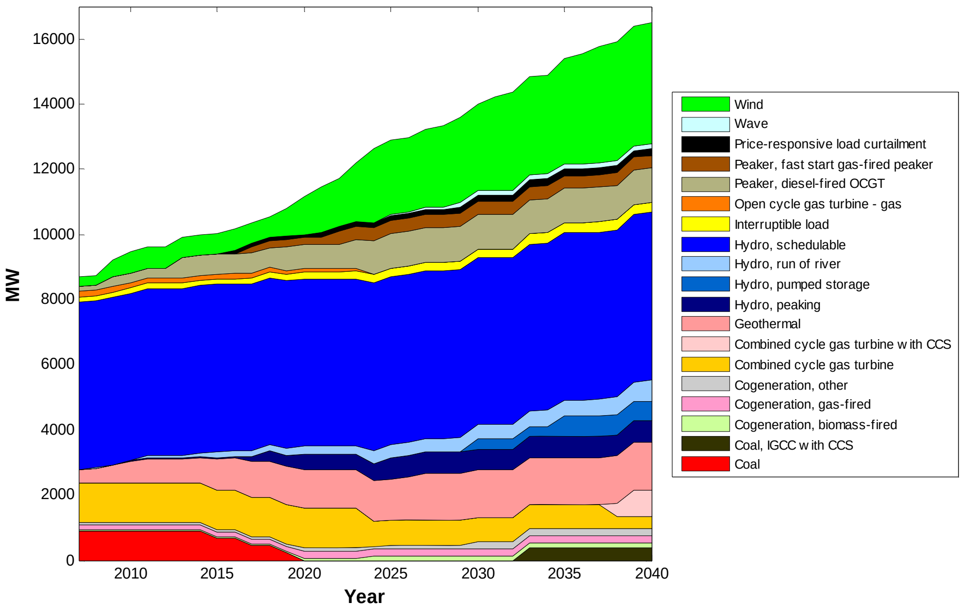
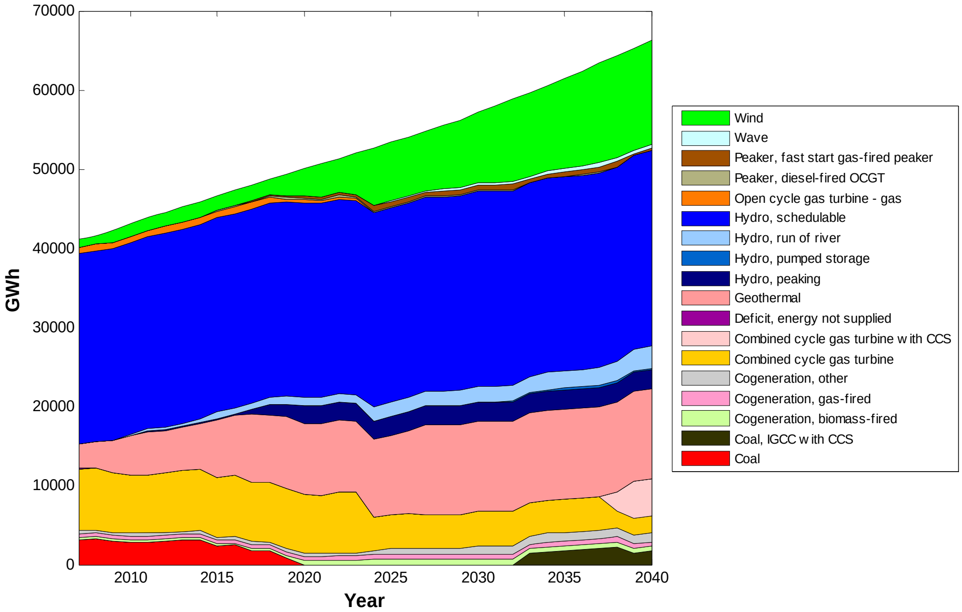


Figure 5 Energy produced by technology, Sustainable Path scenario



The major features of the Sustainable Path scenario are as follows.

- The 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 plant (with Huntly units 1-4, TCC and various other gas-fired plant closing by 2025).
- Major development of renewable generation takes place in both islands. Wind generation is developed extensively with over 2500 MW of installed capacity by 2030, geothermal capacity reaches 1500 MW as early as 2026, and 1400 MW of new hydro is constructed by 2030 (including run-of-river, storage-backed, and pumped modes).
- Biomass and marine generation enter after 2020.
- Coal and gas plant with carbon capture and storage follow after 2030, to help meet increased consumption from electric vehicle charging.
- 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 1000 MW of diesel-fired peakers and 1400 MW of flexible gas-fired generation.
- Demand-side response also assists in meeting peak demand.

South Island Surplus scenario

Figure 6 and Figure 7 illustrate the installed capacity and the energy stackplots by technology and by year for the South Island Surplus scenario.

The key features of the South Island Surplus scenario are as follows.

- As in the 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.
- Coal generation is used for dry-year reserve only until carbon capture and storage becomes available.
- As in the Sustainable Path, we see extensive new wind generation, with over 2500 MW installed by 2030.
- There are also significant amounts of new hydro generation, with about 700 MW of new capacity by 2030, mostly in the lower South Island.
- Geothermal development is slower than in sustainable path, with less than 1000 MW installed by 2030.
- As in Sustainable Path, nearly 1000 MW of diesel-fired peakers and 2000 MW of flexible gas plants are constructed by 2030, to balance intermittent generation, provide dry-year swing, and supply reliable capacity at peak.
- Demand-side response also assists in meeting peak demand.

Figure 6 Installed capacity by technology, South Island Surplus scenario

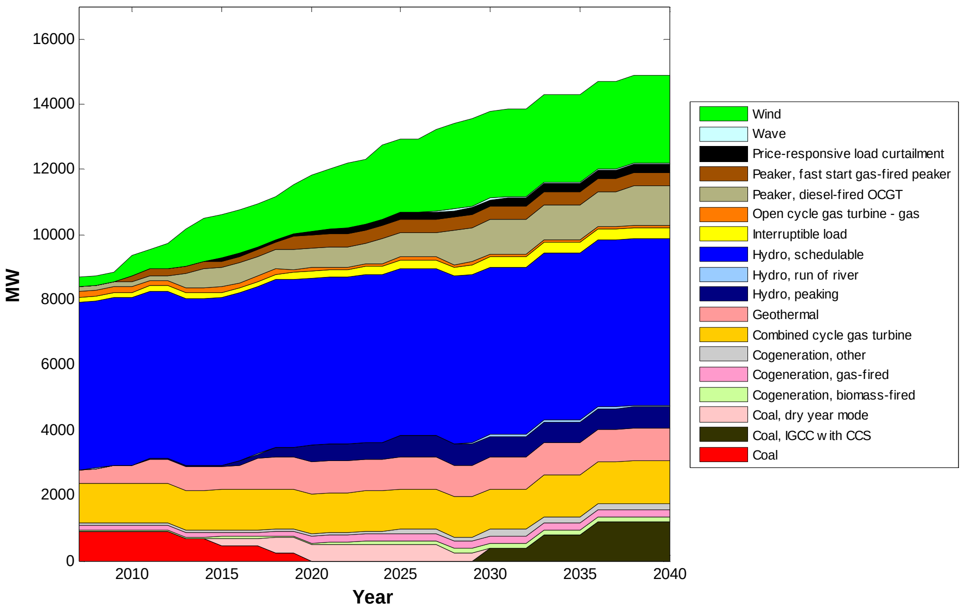
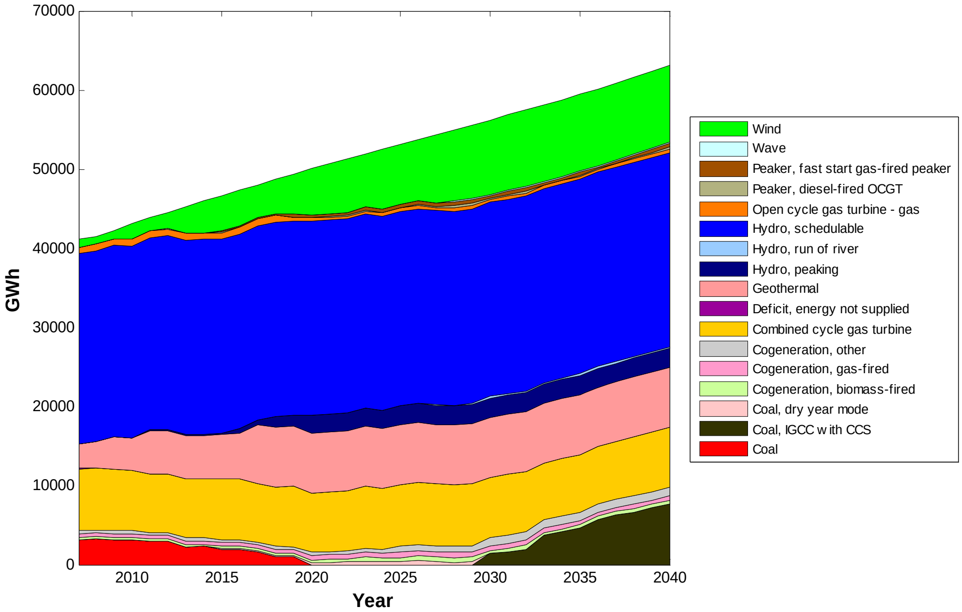


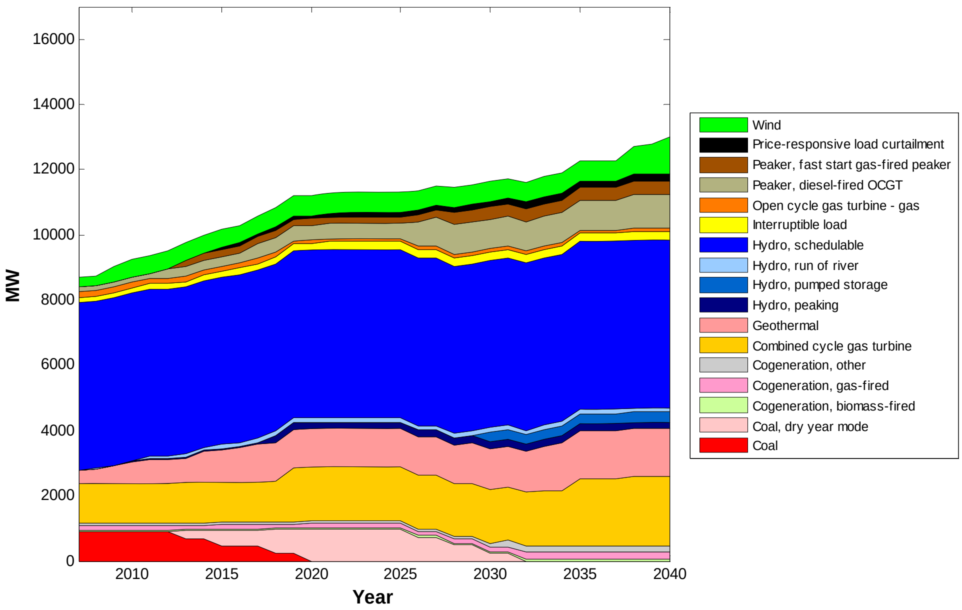
Figure 7 Energy produced by technology, South Island Surplus scenario



Medium Renewables scenario

Figure 8 and Figure 9 illustrate the installed capacity and the energy stackplots by technology and by year for the Medium Renewables scenario.

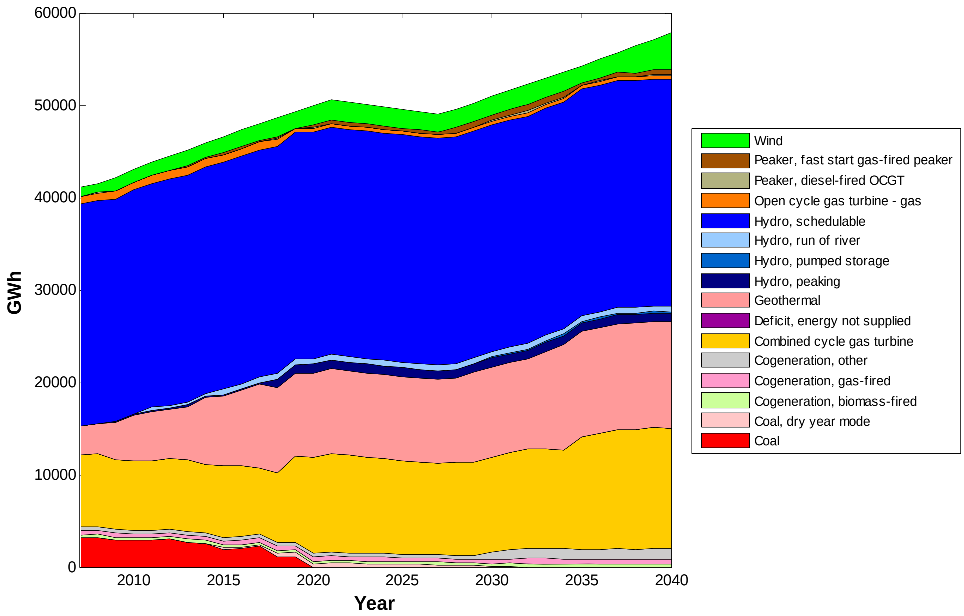
Figure 8 Installed capacity by technology, Medium Renewables scenario



The key features of the Medium Renewables scenario are as follows.

- Due to the phasing out of the Tiwai aluminium smelter around 2025, the medium renewables scenario has the lowest cumulative installed capacity.
- Importation of LNG provides substantial gas supply from 2020 though with fuel costs higher than in the High Gas Discovery scenario, and gas generation remains a major component of electricity supply.
- There is some renewable development, but not as much as in the Sustainable Path and South Island Surplus scenarios; mainly geothermal, with small amounts of hydro and wind.
- There is a requirement for peaking thermal generation, mainly after 2025, when the removal of the very flat Tiwai load leads to a peakier LDC.

Figure 9 Energy produced by technology, Medium Renewables scenario



Demand-side Participation scenario

Figure 10 and Figure 11 show the installed capacity and the energy stackplots by technology and by year for the Demand-side Participation scenario.

The principal outcomes of the Demand-side Participation scenario are as follow.

- Interruptible load 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.
- Electric vehicles increase electricity demand significantly after 2025, but also have an important role to play in supporting the grid via vehicle-to-grid technology.
- Coal- and lignite- fired generation have major roles to play in this scenario. The coal-fired units at Huntly remain in operation until they are replaced by more efficient new plant, with 1800 MW of coal plant (in the North Island) and lignite plant (in the South Island) installed by 2030. As a consequence, sectoral greenhouse emissions are very high.
- There is extensive geothermal development, but little new wind or hydro.
- The output of existing hydro generation is severely curtailed due to difficulties in obtaining water rights.
- Use of thermal peakers is relatively light.

Figure 10 Installed capacity by technology, Demand-side Participation scenario

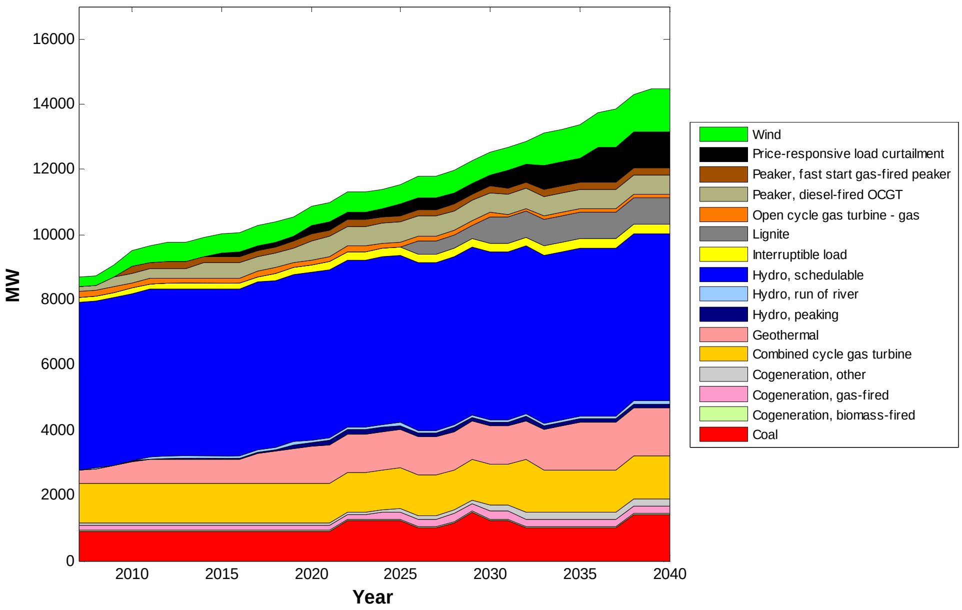
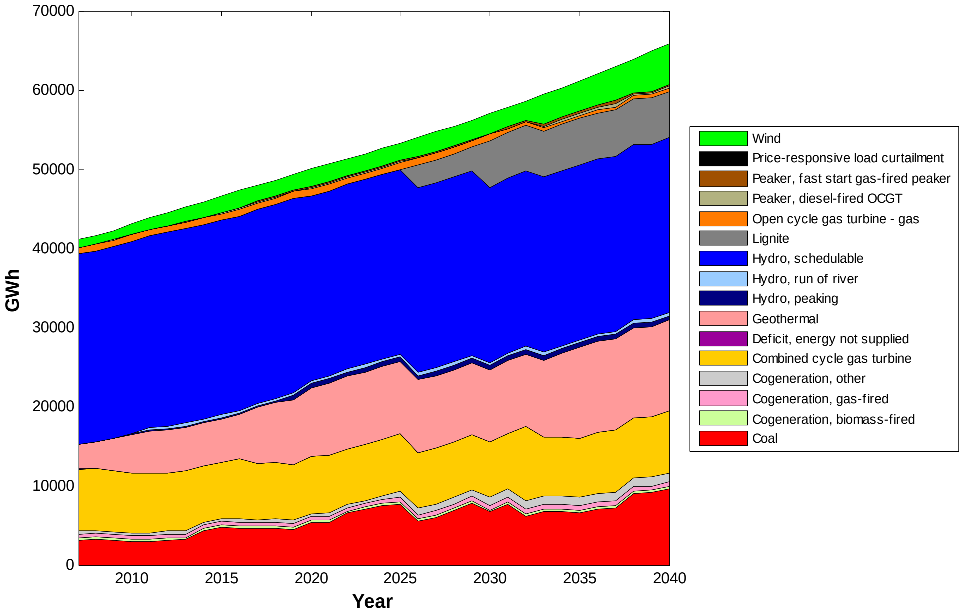


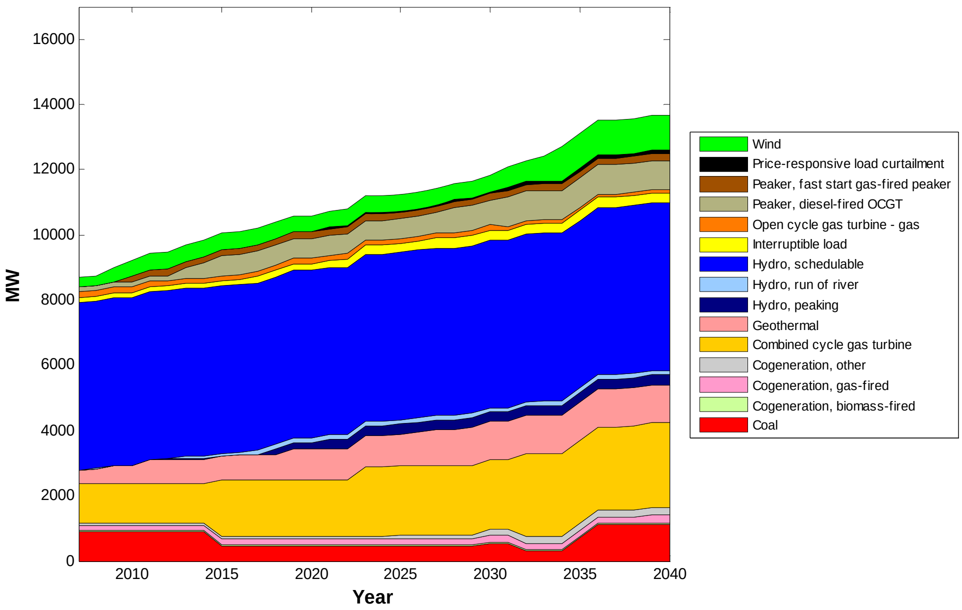
Figure 11 Energy produced by technology, Demand-side Participation scenario



High Gas Discovery scenario

Figure 12 and Figure 13 show the installed capacity and the energy stackplots by technology and by year for the High Gas Discovery scenario.

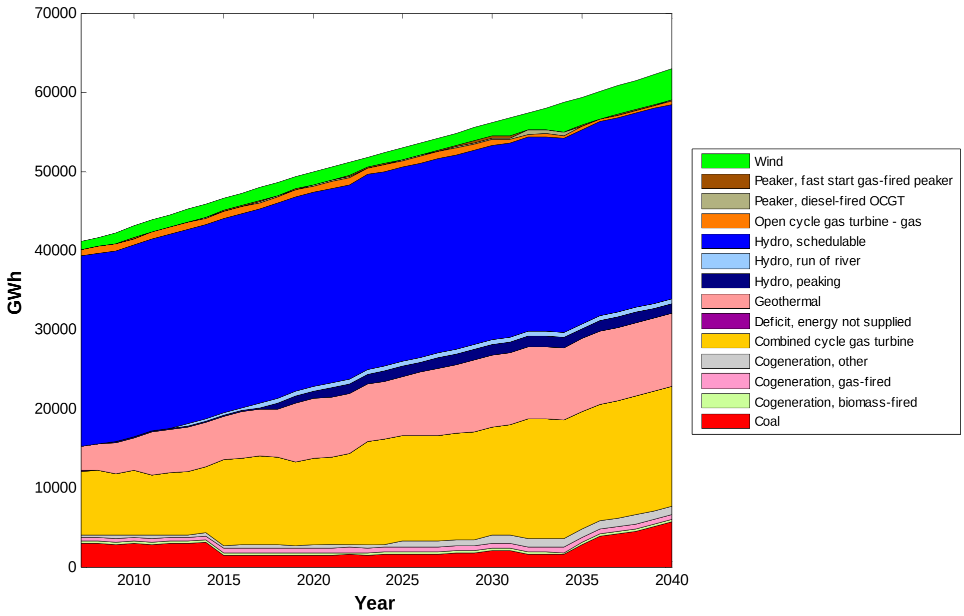
Figure 12 Installed capacity by technology, High Gas Discovery scenario



The main outputs of the High Gas Discovery scenario are as follows.

- With a low gas price of $8/GJ and a moderate carbon charge of $40/tonne, gas generation is favourable. Two new CCGTs are installed by 2030, with gas forming a major component of electricity supply.
- Coal-fired generation is expensive due to the $40/tonne carbon charge. Two Huntly units are closed and replaced with a CCGT by 2015; the others remain in operation until 2030, but no new coal-fired generation is constructed until at least 2035.
- There is extensive geothermal development, plus some wind and hydro.
- There is a requirement for peaking thermal generation.
- Demand-side participation also contributes to meeting peak.
- 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.

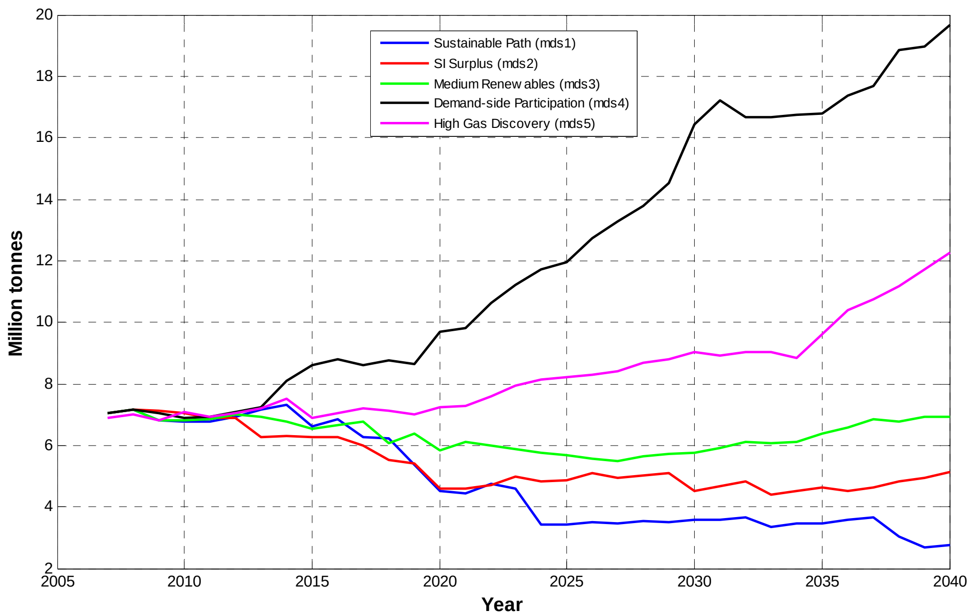
Figure 13 Energy produced by technology, High Gas Discovery scenario



Electricity-sector greenhouse gas emissions

Projections of sectoral greenhouse gas emissions are plotted in Figure 14.

Figure 14 Electricity-sector greenhouse gas emissions for the five scenarios



The Sustainable Path and South Island Surplus scenarios result in major reductions in sectoral greenhouse emissions by 2020. The Medium Renewables scenario projects sectoral emissions remaining roughly constant at or slightly below 2008 levels.

The High Gas Discovery scenario shows an increase in sectoral emissions, by about 32 percent of 2008 levels by 2030. This is driven by increased use of gas for electricity generation. A new coal plant towards the end of the scenario causes an increase in emissions after 2035, though this could be avoided by developing renewables instead.

The Demand-side Participation scenario shows a dramatic increase in sectoral emissions after 2020, as new coal and lignite generation comes online. It should be noted that this is not caused by demand-side participation; it is a coincidental effect, driven by the high electric vehicle demand and the low carbon price. If, post-2030, New Zealand had a target for total onshore greenhouse gas emissions, then increases in electricity-sector emissions may be countered by decreases in other sectors (agriculture or industry).

For example the CO_2-e emission from motor vehicles could be reduced through the penetration of electric vehicles. Based on an electric vehicle and biofuel penetration of 35 percent each in 2040 and assuming that an electric vehicle will produce 0.42 tonnes CO_2-e compared to 2.94 tonnes each year for an average light vehicle, a reduction of around 4 million tonnes of CO_2-e could be achieved. This should be seen as a ballpark number and further work will be done to determine a more precise CO_2-e reduction from the electric vehicle penetration.

Costs

Finally, we present a summary of the capital and operating costs by scenario.

GEM models various types of costs, for each scenario, in each year, and over a range of hydro 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 produces the build schedule that minimises these costs, on a post-tax basis discounted at eight percent real. Generation capital expenditure enters the model as an annualised cost stream.

Modelled costs by scenario are shown in Figure 15 to Figure 19. For ease of interpretation, these plots show pre-tax costs, with generation capital expenditure represented on a lump-sum basis. All costs are expressed in real undiscounted dollars. The figures shown are averages over 73 hydro inflow sequences (in dry years, fuel and carbon costs would be higher than average).

Figure 15 Annual costs, Sustainable Path scenario

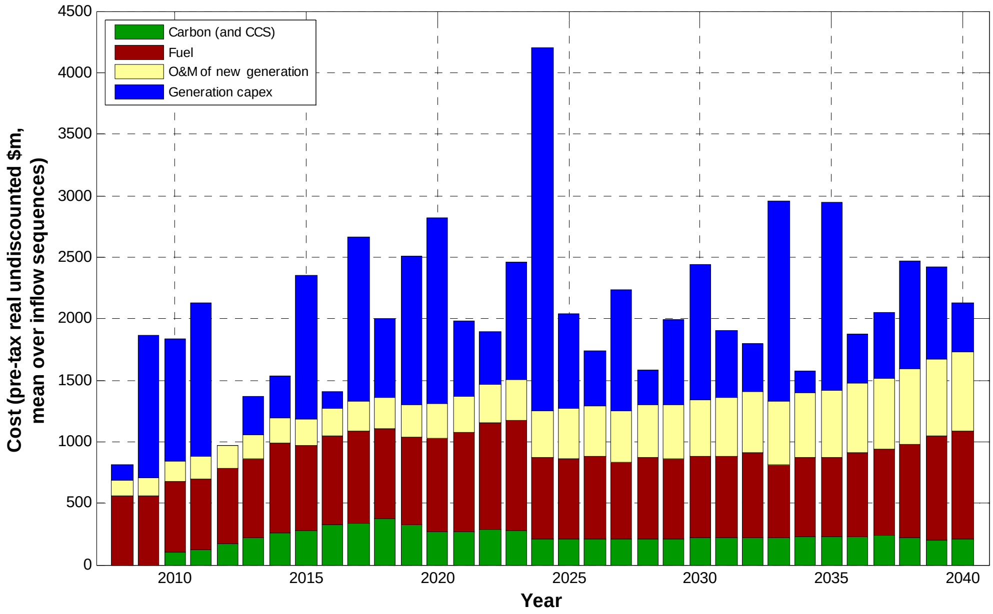


Figure 16 Annual costs, South Island Surplus scenario

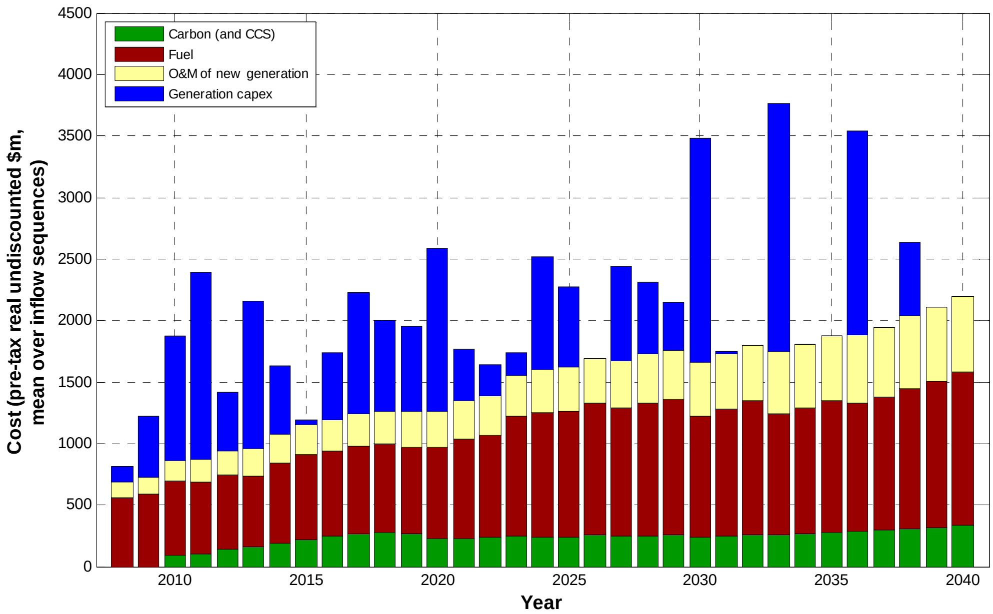


Figure 17 Annual costs, Medium Renewables scenario

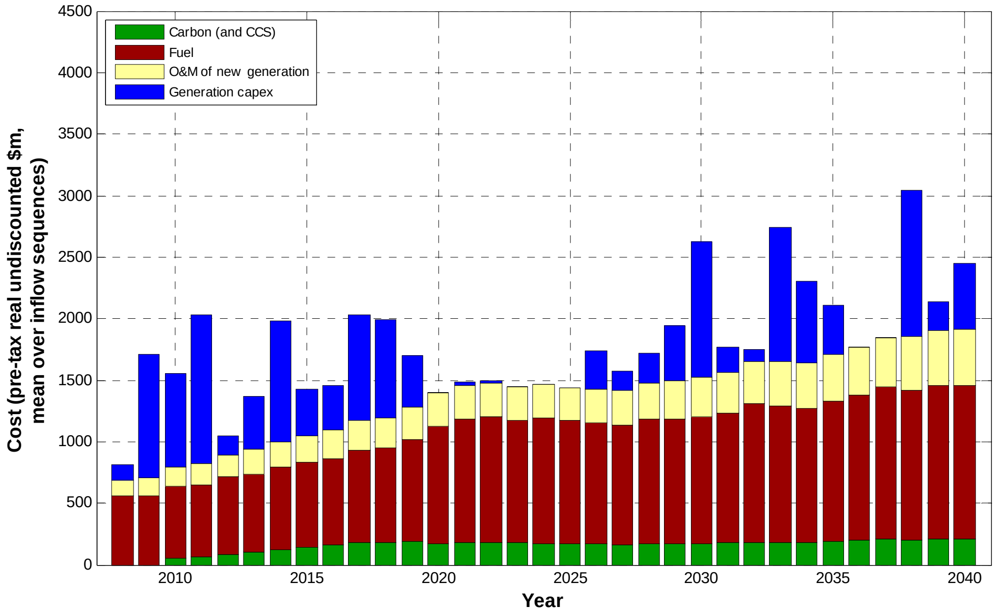


Figure 18 Annual costs, Demand-side Participation scenario

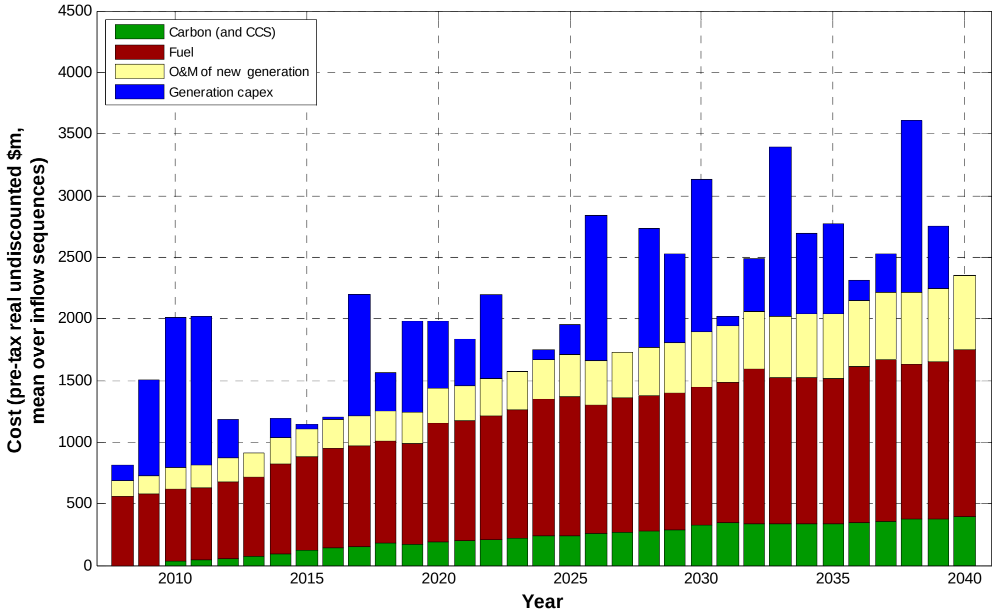
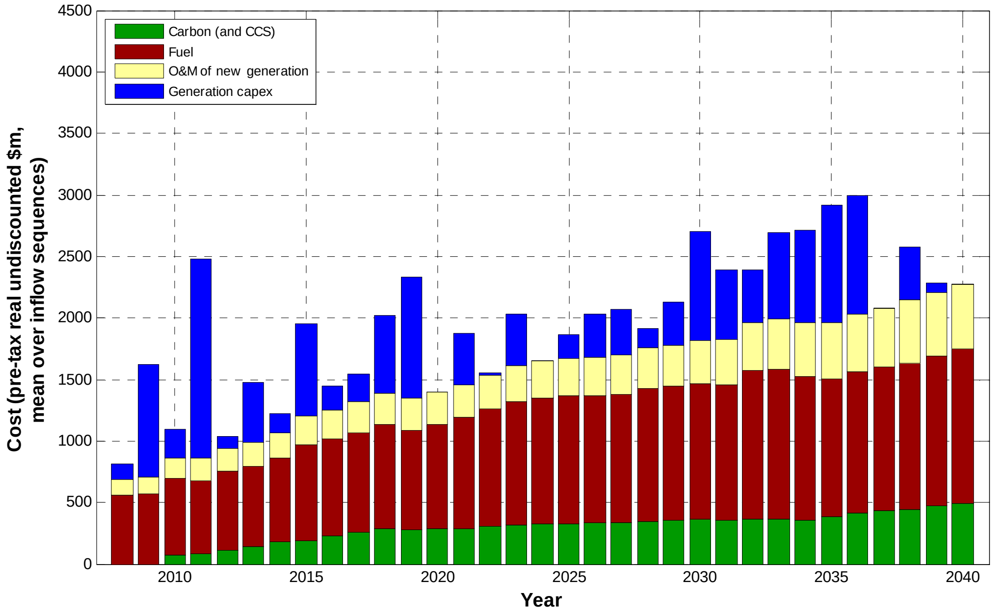


Figure 19 Annual costs, High Gas Discovery scenario



Net present values (NPVs) of supply-side costs are shown in Table 3. A central discount rate of seven percent is used, with five percent and 10 percent as sensitivities. These are pre-tax costs. They include annualised generation capital expenditure, connection costs, operating and maintenance costs of new generation, fuel, electricity-sector carbon costs, and carbon storage costs where applicable.

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 Sustainable Path and South Island Surplus scenarios are the result of high fuel and carbon prices;
- the low costs in the High Gas Discovery scenario are the result of low carbon prices;
- the costs in the Sustainable Path and Demand-side Participation scenarios are partly the result of fuel switching from liquid fuels to electricity in the transport sector, and could be partly offset by reductions in liquid fuel costs; and
- the low costs in the 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 produced is the least-cost response to the exogenous assumptions (given the GEM modelling framework). For instance, the extensive use of renewables in the Sustainable Path and South Island Surplus 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 Commission concludes that 'renewable generation is the best way of reducing supply-side costs in some scenarios'.

Table 3 Pre-tax costs, net present value

Discount rate	Scenario	$m
5%	Sustainable Path	36,129
	South Island Surplus	35,743
	Medium Renewables	30,763
	Demand-side Participation	33,093
	High Gas Discovery	32,554
7%	Sustainable Path	27,016
	South Island Surplus	26,711
	Medium Renewables	23,314
	Demand-side Participation	24,705
	High Gas Discovery	24,487
10%	Sustainable Path	18,602
	South Island Surplus	18,372
	Medium Renewables	16,359
	Demand-side Participation	17,001
	High Gas Discovery	17,013

References

Electricity Commission (2008). Draft 2008 Statement of Opportunities, http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/soo/pdfssoo/2008-draft/Draft%202008%20SOO.pdf.

Glossary of Abbreviations and Terms

Act	Electricity Act 1992
APR	Transpower’s Annual Planning Report
CCGT	Combined cycle gas turbine
CDS	Centralised dataset
GEIR	Grid Economic Investment Report
GEM	Generation expansion model
GIT	Grid Investment Test
GJ	Gigajoule
GPAs	Grid Planning Assumptions
GPS	Government Policy Statement on Electricity Governance
GRR	Grid Reliability Report
GRS	Grid Reliability Standards
GUIRP	Grid upgrade investment and review policy
GUP	Grid Upgrade Plan
GWh	Gigawatt hour – the amount of energy as measured by a rate of one gigawatt for a period of one hour
HVDC	High-voltage direct-current
LDC	Load duration curve
MDSs	Market Development Scenarios
MED	Ministry of Economic Development
MIP	Mixed integer programming
MW	Megawatt
NZES	New Zealand Energy Strategy
Regulations	Electricity Governance Regulations 2003
Rules	Electricity Governance Rules 2003
SOO	Statement of Opportunities
TTER	Transmission to enable renewables