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System Dynamics Modelling of Pathways to a Hydrogen Economy in New Zealand: Final Report

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ii Introduction

This report represents a compilation of work prepared under Objective 6: Carbon to Hydrogen Energy – Proof of Concept of FRST contract C08X0204.

The milestones that relate to this report are:

<u>Milestone 1:</u>
"To develop two scenarios for the introduction of the hydrogen based economy into New Zealand." By June 2004

<u>Milestone 2:</u>
To prepare a "thesis on the 2 scenarios for the transition to a hydrogen economy." by Dec 2004 later revised in consultation with CRL Energy to June 2004.

<u>Milestone 3:</u>
To "develop the model further to be inclusive of distributed generation, potential subsidy schemes, oil/gas costs, costs of CO2 sequestration, health costs."

The 2 principal scenarios were developed in accordance with the contract guidelines to identify key factors affecting the introduction of a hydrogen based energy economy into New Zealand and predict a range of key indicators related to the uptake of hydrogen in the economy. The scenarios include the wider residential, commercial and industrial (RCI) sectors and incorporate four alternative transport technologies as well as hydrogen and electricity generation.

Scenario development is incorporated into a complex quantitative system dynamics (SD) model named UNISYD (Unitec System Dynamics) that analyses New Zealand's energy economy in 13 regions and contains over 500 variables. The fact that the model is complex does not, of course, mean that it is an accurate predictor of the future. However the model has been compared in its development stages with models developed by Electricity Commission and the Ministry for Economic Development (MED). Each model is different. UNISYD is the only model that integrates markets for electricity and hydrogen generation with key vehicle fleet technologies on a regional basis.

The model examines two principal scenarios within which are nested matrices of factors that impact scenario outcomes. The first principal scenario is the *Laissez-faire* scenario, which relies on market forces to determine the time frame for the uptake of hydrogen as a principal energy vector in the economy. In effect, it represents a "No policy" scenario. The second principal scenario is the *Interventionist* scenario, which, although based on the Laissez-faire scenario incorporates policy interventions affecting the speed and depth of hydrogen uptake as a principal energy vector in the economy.

This report is structured into two main parts. First, the model description lays out the assumptions underlying the analysis then the modelling results are presented. Following the results are appendices which include a short description of the modelling control panel, explaining how the model user designs and implements scenarios, the model diagrams and code, and then some background information on the specific hydrogen generation technologies included in the model.

Synthesis

A hydrogen economy in which the transport fleet is fuelled by hydrogen produced largely from New Zealand's coal resources is dependent on 4 principal drivers. System dynamics modelling shows that these 4 key drivers in the conversion of NZ's vehicle fleet are:

- The price of fuel cells.
- The price of oil and natural gas.
- Government policy that encourages infrastructure development for the centralised production of hydrogen.
- Public acceptance of new technology.

The scenarios examined are outlined in Table 1.

Table 1 Scenario description

Scenario	Sub-scenario	Comment
Laissez-faire (LF)	LFwLNG (Base case)	LNG imports available from 2015
	LFNoLNG	No LNG imports are permitted.
	LFwH2ICE	All vehicle technologies compete.
Interventionist (IV)	HighElec	Electricity production grows at 90% of GDP
	HighOilNG	NG and oil price increases at 8% p.a.
	NoH2	Hydrogen generation is not permitted.
	CP	Optimistic forecasts of hydrogen demand encourage building of large hydrogen generation plants.
	HighCTax	CTax of $25/t in 2008 to $100/t in 2013

A summary of the range of results of key parameters obtained from the model under the scenarios examined is shown in Table 2

Table 2 Range of values of key parameters at 2050.

Parameter at 2050	Minimum	Scenario	Maximum	Scenario
Fossil Carbon Emissions (Mt/yr)	17	HighCTax*	27	HighElec
Carbon tax revenue ($million/yr)	665	NoH2	1683	HighCTax
Electricity Generation (PJ/yr)	234	HighCTax	336	HighElec
Av. Electricity Price 2020-2050 (c/kWh)	9.6	LFwoLNG	15.6	HighElec
Gas and coal use (PJ/yr)	239	NoH2	511	HighElec
Proportion of HFCVs (%)	60	LFwH2ICE*	65	HighCTax
Hydrogen production (kt/yr)	745	LFwoLNG*	881	LFwH2ICE
Av. NI hydrogen price 2030-2050 ($/kg)	5.4	CP	6.3	LFwH2ICE

* excludes NoH2 scenario

Two key questions impacting the growth of the hydrogen economy are:

- Will the predicted reduction in fuel cells occur to ensure that fuel cell vehicles can compete on cost with internal combustion engine vehicles (ICEVs) and emerging battery powered electric vehicles (EVs) as the prime mover of the motor vehicle?
- Will the government encourage infrastructure development by underwriting hydrogen projects that carry uncertain short term economic returns but have large potential benefits to society through reduced pollution, increased economic security and reduced greenhouse gas emissions?

Part I: A Guide to the Systems Dynamics Model of New Zealand’s Energy Economy

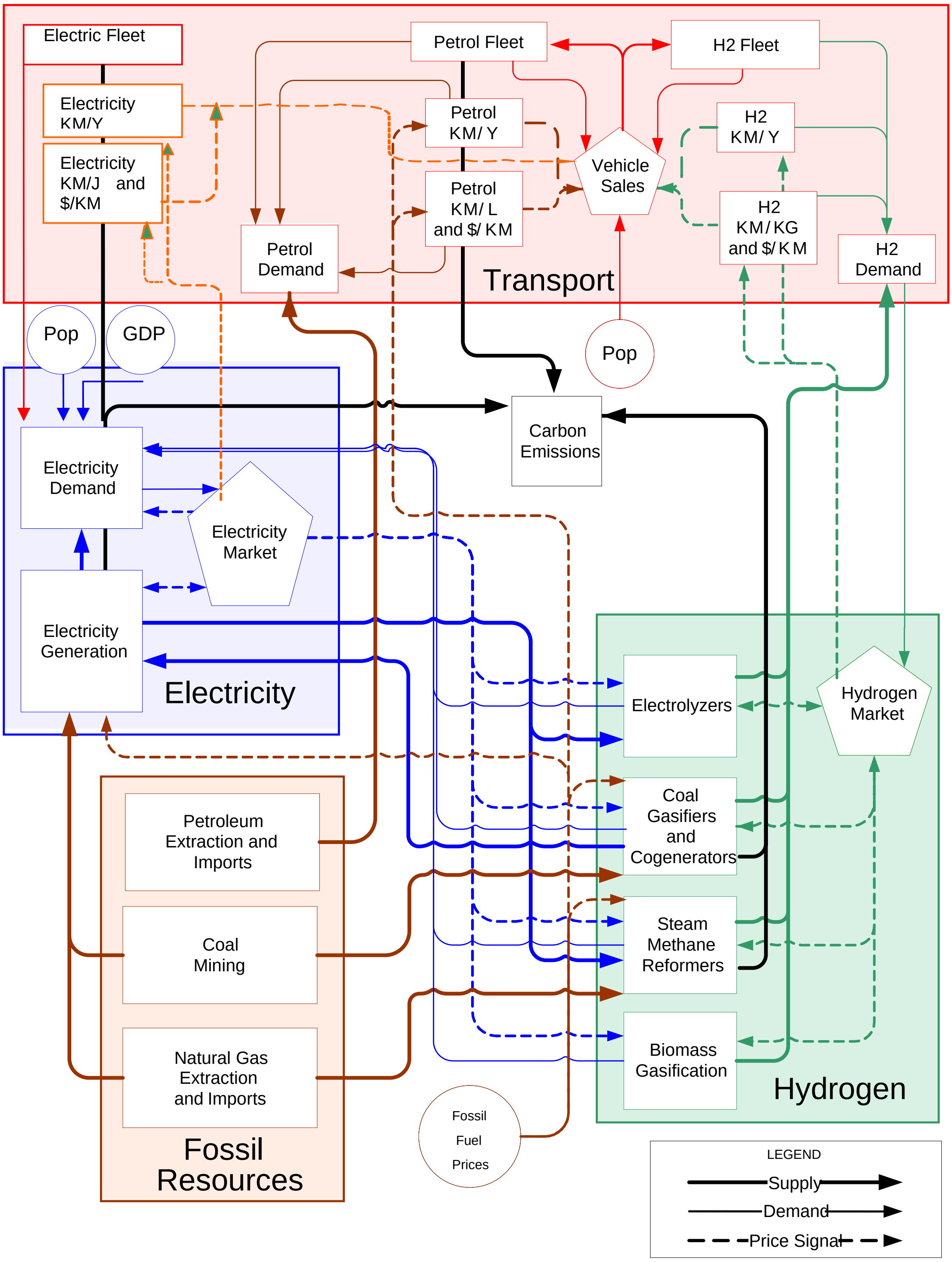

Figure 1: Model Block Diagram
Note: Major modelling decision processes are shown in trapezoids.
Exogenous drivers are circled.

1 Overview

The block diagram in Figure 1 highlights the model's design. It is structured such that economic, technological and socio/political drivers of a hydrogen economy impact 4 main sectors: the transport fleet, electricity production, hydrogen production, and fossil resources. Certainly, these sectors are further broken down to ease in discussion and design. Each significant model sector will be covered in the ensuing sections. Existing model development and discussions of potential future work are included. Before the model is detailed, the following section details the fundamentals of system dynamics.

2 System Dynamics

System dynamics modelling was initially designed to solve manufacturing problems. In 1958, it was first applied to a production-inventory situation, as reported by Jay W. Forrester in the *Harvard Business Review.*[1] The modelling technique is perhaps best known for being used in the analysis in the book *Limits to Growth,*[2] commissioned by the Club of Rome in 1972, which issued warnings of world-wide environmental crisis and resource shortages in the 21st century, barring changes in human behavior.

Since then, it has grown to be used to model everything from "International Capital and Mexican Development"[3] to "Institutions, Ecosystems and Sustainability,"[4] Keynes' full-scale trade cycle,[5] and "Mining Industry Investment Decisions within the Context of Environmental Policy."[6] Radzicki claims it is particularly useful in segments of economics that "adhere to an evolutionary view of economic change", including institutional, ecological, post-Keynesian, and behavioural economics.[7]

There are two points that tend to differentiate system dynamics models from common traditional economy models. First, traditional economic modelling often relies upon the assumption of globally rational decision making. System dynamics models may include the assumption of rationality, but the system dynamics framework more easily allows for the behavior of economic agents to be modelled as boundedly rational—an assumption more likely to be true in reality.

Second, while traditional economic models achieve equilibrium in discrete time periods *a* and *b*, system dynamics modelling represents dynamic disequilibrium throughout time, following a path from *a* to *b*. It effectively models the continual transition towards equilibrium as markets dynamically adjust to changes in supply and demand, much in the way real economies operate.

---

[1] J. W. Forrester, "Industrial Dynamics: A Major Breakthrough for Decision-Makers.," Harvard Business Review 36 (1991).
[2] Donella H. Meadows, Dennis L. Meadows, Jørgen Randers and William W. Behrens III, The Limits to Growth (New York, NY: Universe Books, 1972).
[3] John T. Harvey and Kristin Klopfenstein, "International Capital and Mexican Development: A Systems Dynamics Model," JOURNAL OF ECONOMIC ISSUES XXXV.2 (2001).
[4] Institutions, Ecosystems, and Sustainability, Ecological Economics, ed. Robert Costanza (Washington, D.C.: Lewis Publishers, 2001).
[5] John T. Harvey, "Keynes' Chapter 22: A System Dynamics Model," JOURNAL OF ECONOMIC ISSUES XXXVI.2 (2002).
[6] Bernadette O'Regan and Richard Moles, "A System Dynamics Model of Mining Industry Investment Decisions within the Context of Environmental Policy," Journal of Environmental Planning and Management 44.2 (2001).
[7] Michael J. Radzicki, "Mr. Hamilton, Mr. Forrester, and a Foundation for Evolutionary Economics," JOURNAL OF ECONOMIC ISSUES XXXVII.1 (2003).

As the development path of a hydrogen economy in New Zealand is of interest in this research, system dynamics modelling is appropriate as it can be used to intuitively model the key elements that influence the dynamics of the economy and energy system.

2.1 Building Blocks of System Dynamics

Systems dynamics modelling imposes an intuitive mathematical structure on the relationships between different elements in the economy and energy system. This structure is based on the positive (i.e., increasing) and negative (i.e., decreasing) feedback loops that govern the system.

There are three defining elements in systems dynamics modelling—stocks, flows, and feedback (Figure 2.16). Stocks are reservoirs where objects accumulate or dissipate, and are usually modelled as "rectangular-shaped icons intended to conjure up images of bathtubs."[8] Flows dictate movement of objects in and out of stocks, and thus are typically "represented by icons resembling pipe and faucet assemblies that fill or drain the stocks."[9] Feedback is the transmission and return of information between stocks and flows. Information about the number of objects in one stock can move throughout the system and eventually return to alter the flows filling and/or draining the stock, creating a feedback loop.

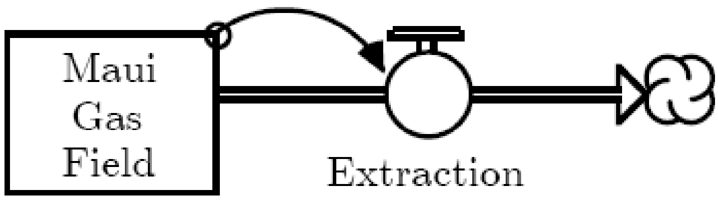

Figure 2: Sample System Dynamics Model

Figure 2 is a very simple example of a system dynamics model. Reserves of natural gas in New Zealand's *Maui Gas Field* is the stock, *Extraction* is the flow, and the line connecting the two is the information feedback. Extraction is dynamic, much as you would expect; the operator owning the field will want to optimise returns on his investment developing the field. Thus, the rate of extraction (controlled by the "valve" on the flow in the figure) is a function of gas remaining in the field. A profit maximizing field operator would, if Maui was the only source of natural gas in New Zealand, follow Hotelling's rule of the extraction of exhaustible resources,[10] rather than statically extracting gas at a constant rate.

This simplistic representation of an underlying complex system is one of the major benefits of system dynamics. Policymakers, modelers, and schoolchildren alike can look at the above picture and have a sense of what it represents, without having to delve deep into the underlying mathematics. This, above all, was the incentive driving the decision to model a New Zealand's energy future using system dynamics, and more specifically, with Stella[11] system dynamics software.

[8] Radzicki, "Mr. Hamilton, Mr. Forrester, and a Foundation for Evolutionary Economics."
[9] Ibid
[10] Harold Hotelling, "The Economics of Exhaustible Resources," The Journal of Political Economy 39.2 (1931).
[11] Jeremy Wallis, Karim Chichakly, Steve Petrson and Barry Richmond, Stella Research Software, 7.0.1 for Windows ed. (Hanover, NH: High Performance Systems, Inc., 2001).

3 Natural Gas Resources

The *Natural Gas Resources* sector of the model is where all the modelling decisions surrounding the pricing and distribution of natural gas take place. Four separate dynamic processes are occurring simultaneously: determination of demand, extraction and importation, pricing, and allocation.

3.1 Demand

To ease in the creation of this sector, natural gas is demanded in a specified order. It is as though during each time step of the model people line up and gas is dispensed on a first come first serve basis. The amount being demanded by each "person" in line is sensitive to price signals either directly or through the price of value-added outputs like electricity or hydrogen. The ordering used is roughly based on willingness to pay. Those asking for natural gas, in order of priority, include reticulated residential, commercial and industrial (RCI) consumers, combined heat and power generators, steam methane reforming to hydrogen plants, combined cycle and single cycle electricity generators, and the chemicals industry. The only exogenously defined gas demands are domestic and industrial gas demands excluding co-generation, which are set to be static at 2005 levels.[12] Methanex and other chemical industry demands are presumed to fall to zero when direct supply gas prices rise to $4/GJ.

3.2 Reserves or Imports

The concept of "reserves" used in this sector can be confusing. Natural gas is only considered a "reserve" in this model if it is a developed gas field attached to a pipeline and capable of producing on demand (Table 3).

Table 3: Reserves at 1 January 2006[13]

Field	Reserves (PJ)
Kaimiro/Ngatoro	9
Kapuni	286
Maui	529.4
McKee	68.3
Mangahewa	40.6
TAWN	32.1
Rimu	22.9
Kauri	38.8
Pohokura	700
Turangi	144
Windsor	0.8
Other Fields	8

Each reserve has total resource[14] and maximum extraction rate attributes (Table 4). Potential reserves in un-developed fields are not included. As planned, 281 PJ in reserves become available in the Kupe field starting in 2009.[15] An additional field,

[12] Energy Data File, Sept. 2006 ed. (Wellington, New Zealand: Ministry of Economic Development, 2006).
[13] Ibid
[14] Energy Data File.
[15] Kupe Gas Project Community Newsletter (Origin Energy, June 2006).

dubbed “Other New,” encapsulates other new discoveries that occur at the average rate of discover since Maui, or about 44 PJ per year.[16]

Table 4: Maximum Field Extraction Rates

Field (Time)	PJ/Yr
Kaimiro	0.51
Kapuni	25.13
Kupe	20.00
Mangahewa	7.98
Maui (2006)	97.50
Mckee	8.18
Ngatoro	0.49
Pohokura	30
Rimu	3.62
TAWN	9.83
Other (New)	.05 * Other Reserves

Actual extraction and importation rates are set according to demand. The model utilises domestic natural gas reserves first, at production rates up to the maximum defined by reserve characteristics. If there is remaining demand to meet, the model tries to import gas from Australia. The amount of Australian gas available is extrapolated from historical data on gas reserves and production and published data on expected future exports of LNG[17]. The variables *Ignore LNG?* and *LNG Importation Begins* in the Control Panel govern firstly whether imports occur and secondly the timing of said imports. Availability of imports determines viability of new investment in large-scale natural gas usage in the *Electricity* and *Hydrogen Generation* sectors, as current projected resource availability does not allow for much increase in gas usage.

3.3 **Pricing**

Pricing in the *Natural Gas* sector is based on supply-side economics, and can be broken down into wellhead prices, transmission (or pipeline) tariffs, and reticulation tariffs. Direct-supplied consumers such as the electric utilities and the chemicals industry do not pay reticulated tariffs. Smaller consumers, such as residential consumers and commercial businesses (including distributed steam methane reformers producing hydrogen), do. Wellhead prices follow a simple supply curve, with domestic gas supplied at current wellhead prices $7.75/GJ.[18] When demand is greater than the supply of domestic gas, the wellhead price is replaced with the price of imported LNG determined by

$$\text{LNG} = [2.003 + 0.0493 \times (\text{US\$Oil Price/bbl} - 1)+1.25]/\text{Exchange rate}$$

if it is available. Otherwise, prices rise until supply-demand equilibrium is met. The modeller has further control over gas price increases by changing the *NG Price Increase Annum* variable. This applies a per annum increase in the pre-pipeline gas price, whether the feedstock gas is domestic or from LNG.

[16] Jonathan Leaver, "Production since Maui," ed. Andrew Baglino (Auckland, New Zealand: 2003),.
[17] AGA - Gas Statistics, 2002, Website, Australian Gas Association, Available: http://www.gas.asn.au/factsandfigures/statistics.php?tab=statistics, November, 25 2003.
[18] New Zealand Energy Outlook to 2030 (Energy Information and Modelling Ministry of economic Development, 2006), Figure 8.1.

The pipeline tariff used in the model is $1/GJ, the average tariff as estimated from the MED's "Review of the Natural Gas Sector."[19] The reticulated tariffs for industrial consumers and for residential consumers are best fit to the average reticulated gas prices tabulated in the EDF.[20] No dynamic assumptions are used, and the market effect of raised wellhead prices on transmission tariffs is not modelled. The changing source price is the only dynamic price signal sent by the *Natural Gas Resources* sector. Prices used are on an HHV (higher heating value) basis.

3.4 **Natural Gas Allocation**

As gas is sold on a first come first serve basis at each time step, it is not possible for there to be a difference between the gas demanded and the gas consumed. In other words, take-or-pay contracts, or any longer-term natural gas commitments for that matter, are not in the model. Consumers only demand the natural gas they need for that time step and receive and use exactly that amount. This is a gross simplification of a highly complex natural gas system, but for this version of the model it is simple to maintain and dependable in operation.

3.5 **Future Work**

Almost all aspects of this sector could be reworked. Indeed, the very queue system mentioned above is not representative of NZ's gas market reality. Gas is traditionally a seller's market; demand side willingness to pay dictates prices. Basing such pricing on supply side economics is convenient but needs further refining. Adding the ability for consumers to form long-term contracts with natural gas suppliers would add a level of realism and dynamism. Including a spot market where demand-side economics are driven by willingness to pay would also improve the functionality of this system.

Modelling of the locally reticulated market can be improved. In its current version, the model assumes reticulated demand will remain flat at current gas prices but reduce with an elasticity of 0.1 with price increases. Such a system may be accurate. However, with reticulation tariffs in New Zealand (NZ) among the highest in the OECD, including dynamic interaction between rising feedstock prices, suppressed reticulation demand, and rising tariffs would improve the model. A good examination of the regulatory and market conditions has already been done by MED.[21] Its findings and those of others could certainly be included in future versions of this sector.

4 Coal Resources

The *Coal Resources* sector operates similarly to the *Natural Gas Resources* sector, though with less dynamic interaction. While designing the model the decision was made to leave coal prices exogenously defined, as no shortage of coal is expected in the 50 year time horizon of the model. The price used is $3.5/GJ rising linearly to $4.0/GJ by 2015, and was adapted from predictions made in New Zealand Energy's Outlook to 2030[22]. Hence the only useful information to be gathered in this sector is the total amount of coal moving through NZ's energy economy in response to these static prices,

[19] Review of the New Zealand Gas Sector: A Report to the Ministry of Economic Development (Sydney, AU: ACIL Consulting, 2001).
[20] Energy Data File, Table I.8.
[21] Review of the New Zealand Gas Sector: A Report to the Ministry of Economic Development.
[22] New Zealand Energy Outlook to 2030, Fig. 7.2.

which are on an HHV basis. Demand for exports and domestic and industrial uses remain static at 2005 levels[23].

4.1 Future Work

This simplistic description of NZ's coal market can be greatly expanded. Assessments of existing mines and trading partners and potential new ones should be added in a system similar to that employed in the *Natural Gas Resources* sector. Major coal consumers should be able to contract coal from the various mines/exporters at prices driven by willingness to pay. New coal-burning utilities should be able to locate themselves near mines, and therefore avoid transport costs. Future versions of the model might include all such interactions.

The model assumes all coal is bituminous with energy density values taken from the EDF "average used in NZ" value[24]. The types of coal (from lignite to bituminous) found in NZ have specific extraction and transportation costs, and these should be identified separately and incorporated. In many cases, differing types of coal have starkly different qualities and uses.

5 Electricity Demand

Major changes in this version of the model relate to the representation of demand and supply within the electricity sector. The model now disaggregates the electricity sector by 13 regions harmonised with those used by the Electricity Commission[25]. The benefits of a regionally disaggregated electricity sector include region-specific carbon emission profiles, hydrogen plant placement by region, and compatibility with a future model that accurately includes limitations of the national grid.

The *Electricity Demand* sector of the model can be broken into two segments, a statically defined latent demand growth, and the dynamic interaction of this definition with price signals coming from the *Electricity Generation and Pricing* sector. Initial national demands for the residential, commercial, and industrial (RCI) sectors are set at 2008 levels from the EDF.[26] When considering these demands, combined heat and power generation is aggregated with the industrial sector demands, with data also coming from the EDF.[27]

5.1 Regionalising Electricity Demand

Electricity demand is broken down from the national demand numbers by sector into regional demands using static regional demand factors (Table 5). These regional demands were taken from Figure 23 of the Electricity Commission's Initial Statement of Opportunity in July 2005.[28] Regional demands grow in concert – such that no regional demand grows at a faster rate than any other.

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[23] Energy Data File, Figure C.2.
[24] Energy Data File.
[25] .Initial Statement of Opportunities, (New Zealand: Electricity Commission, 2005).
[26] Energy Data File, June 2007 ed. (Wellington, New Zealand: Ministry of Economic Development, 2007), Table G.1b.
[27] Energy Data File, Table G.1b.
[28] Initial Statement of Opportunities.

Table 5: Regional Electricity Demand 2005 (GWh/y) and Demand Factors

Region	GWh	Demand Factor
Auckland	5800	0.155
Bay Of Plenty	4600	0.123
Canterbury	3800	0.102
Central	1700	0.046
Hawkes Bay	1700	0.046
Nelson&Marlborough	1100	0.029
Northland	3700	0.099
Otago/Southerland	7500	0.201
South Canterbury	700	0.019
Taranaki	800	0.021
West Coast	200	0.005
Wellington	2700	0.072
Waikato	3000	0.080

5.2 Static Demand Sector Modelling

The static demand definition used in this sector for the RCI sectors can be toggled via the *Tag Demand to Pop?* in the model Control Panel. The difference between these two options is large, amounting to about a 100 PJ difference in total RCI demand by 2050.

When this switch is on, the model increases electricity demand in constant ratio to population growth. Averaged over the 1990s, for every 1% increase in population there was a 1.16% increase in residential demand, 1.5% increase in commercial demand, and 1.39% increase in industrial demand. These ratios used were calculated from electricity usage[29] and population growth data[30] from the 1990s.

However, when this switch is off, the model maintains growth based on GDP growth predicted by the New Zealand's Energy Outlook to 2030[31] of 3.3% in 2007 declining to 1.5% in 2027 and staying at 1.5% to 2050. Electricity growth is expected to grow in a ratio of 0.7:1 with gross domestic product (GDP).

5.3 Integration of Dynamics into the Demand

The actual demand sent to the *Electricity Generation and Pricing* sector is defined by more than just the static demand models mentioned above. The static demand models define the latent electricity demand within each region and demand sector, and this latent demand is modified endogenously in response to changes in regional electricity prices. The response is based on a price elasticity calculated by the MED during the 2001 low-lake-level crises[32], when price increases of 20 c/kWh induced a 2% reduction in demand.

[29] Aga - Gas Statistics, Energy Data File, July 2002 ed. (Wellington, New Zealand: Ministry of Economic Development, 2003).
[30] Pragati Vasisht, Profile of New Zealand Motor Vehicle Fleet (Auckland, NZ: Centre for Sustainable Energy Initiatives, Unitec Institute of Technology, 2002).
[31] New Zealand Energy Outlook to 2030, Fig 3.1.
[32] Greg Sise, Siobhan Ruffell and Peppy Adi Purnomo, Nz Electricity Outlook: Dry Year Risk 2003/04-2006/07 (Wellington, NZ: Energy Link Limited, 2002), Table 6, p.14.

5.4 **Efficiency as a Variable**

The *Efficiency Target Reduction* and *Efficiency Target Year* variables in the model Control Panel allow the modeller to see the effects of attaining a specific energy efficiency target, by linearly reducing overall demand until the target reduction percentage is achieved in the target year.

5.5 **Future Work**

Applying price-induced demand reductions equally across RCI sectors should be further refined. Each sector would normally behave differently, as price signals in the New Zealand's wholesale market do not reach residential, commercial, and industrial customers equally. Currently, only the direct-supply spot-market electricity contracts between large industrial users and producers have unimpeded market signals. Certainly, the latency between spot-market price changes and residential and commercial electricity rate changes is long. Different responses by sector may be included in future versions of the model. More research into electricity demand elasticities is also warranted.

Further disaggregating is possible within the RCI sectors. Trends in appliance stocks and floor space could be studied. Water heating substitution between gas and electric, for instance, might be dynamically modelled, adding realism to both the *Electricity Demand* and *Natural Gas Resources* sectors.

The demand as modelled here is total annual demand. Peak demand vs. base load demand throughout the daily NZ load cycle is not modelled. It could be, by decreasing the step size and adding modified load characteristics. Without involving the peak electricity needs in the model, the exact mix of generating capacity and amount of overall installed capacity as predicted in the model will undoubtedly deviate.

6 The Electricity Market

The model spends the bulk of its time within the confines of the *Electricity Generation and Pricing* sector coordinating the complexity of the electricity market. The sector is broken down into four steps—defining the amount of electricity needed from the centralised generators, associating a national wholesale spot price with that amount of electricity, determining regional wholesale prices (post-transmission but pre-distribution), and finally, setting regional retail prices.

When determining the amount of centralised grid-electricity needed, the model takes the total requested by the *Electricity Demand* sector for that region, subtracts the amount of electricity that is met by on-site means within that region (either via solar power, combined heat and power, or other forms of distributed generation), and corrects for grid efficiency losses of 6.3%.[33] This final regional need is sent to the *Wholesale Price Calculation* decision-diamond where the electricity market simulation occurs.

The electricity market maintains one market clearing wholesale spot price, because on a national level, all generators of all types and in all regions compete in an open market. Once that market is cleared, the model goes to the regional level to translate the market equilibrium at the national level into regional prices.

[33] Energy Data File, Chart G.5.

Every time step, the quantity of electricity produced in a particular region is compared with the quantity demanded by consumers in the region. Regions with shortfalls are considered electricity-importing regions. Consumers within importing regions pay additional transmission costs to cover the imports.

6.1 Generator Capacity and Production

During every time step the various centralised generators of each type and in each region reassess their ability to sell power, and at what cost. For those running on fossil fuels, changes in production may be due to shortages in their feedstock. For the hydro dams, it might be changes in lake levels. However, most of the generators have capacities that change very little—the only thing that affects how much power they generate is the going market rate of bulk electricity, i.e. the wholesale price.

6.2 Generator Definition

All the electricity plants of each type in a given region are aggregated into one plant that is capable of supplying an aggregate number of GWh/y at one supply cost. For example, there are 13 hydropower plants in the model (one for each region) with different capacities and supply curves. This simplifies the model design. To simulate each hydropower dam individually was deemed to be too cumbersome. Each generation type has its own *Generation* sector, where the specifics of this aggregation process reside.

6.3 Generation Sequence

In this version of the model, each plant's supply curve (in GWh/y) is constructed as follows:

$$quantitysupplied = lesserof \begin{pmatrix} \left(\dfrac{offerprice}{costofgeneration}\right)^{losswillingness} \\ or \\ 1.0 \\ \end{pmatrix} * potentialproduction$$

Thus, for offer prices over the cost of generation for the plant, the plant will operate at full capacity. For prices less than the cost of generation, the plant will produce exponentially less, according to the variable *Loss Willingness*, which represents the plant's tendency to sell power below profitability to retain market share, or avoid being mothballed.

6.4 Price Setting

The wholesale price is one of the most important parameters in the entire model. For every time step, the model attempts to equilibrate the demand for centrally generated electricity with the supply curves of the various plants by changing the offer price. Additionally, the wholesale price forms the basis of future wholesale electricity prices, which play a crucial role in the model's build-new-plant decision. However, in the short term, this price signal is sent to each plant, that, by the logic above, provides power accordingly.

As Stella software lacks the ability to do simultaneous equation solving, minimizing wholesale price while meeting central generation needs and maximizing generator profit is impossible. Nonetheless, at each time step, the model tries indefatigably to make an educated guess at this optimal price. It does so by testing the plants' responses to various percentage increases and decreases in price from the wholesale price in the previous time step. The model then determines the minimum wholesale price necessary to provide sufficient power. In some cases increasing the price is insufficient to suppress demand to match the generation capacity. Then the maximum increase in price is chosen (currently 25% increase per time step) due to a production shortfall. In the case of a shortfall, government generation from the diesel Whirinaki plant provides power at a minimum price of 20 c/kWh.[34]

In this way, with each time step the model moves the wholesale price closer towards equilibrium, but in most cases, with construction of new plants and shortages in fossil fuels, it rarely finds one. Production shortfalls trigger large price increases and conservation in the demand sectors. Additionally, higher wholesale prices encourage new capacity, something that is needed to keep pace with increasing demand.

6.5 Transmission and Distribution

After the market-clearing national wholesale price is determined, pre-transmission retail prices at a regional level are set at the supply cost of the marginal plant providing power to the region. In electricity-exporting regions, the marginal plant is the most costly plant situated in the region that is producing power in the current time step. In electricity importing regions, the price is set by the most costly plant in use nationwide, plus the average national cost of transmission over Transpower's grid.

Power from the centralised plants must be transmitted over Transpower's high (110 kV – 220 kV) voltage transmission grid to get power from region to region. Also, local line companies play a distribution role between the grid and the final consumer. The costs of transmission and distribution are simplified to 2 and 3 c/kWh tariffs respectively, both of which are estimates arrived at by fitting these costs to the wholesale and average prices in the January 2006 EDF.[35]

The sum of the regional wholesale price plus transmission (in importing regions) and distribution costs is considered the region's average retail cost of electricity, which the model uses to calculate specific RCI electricity prices. These are calculated using ratios as seen in the January 2006 EDF[36]. Sectoral prices are linked elsewhere in the model as inputs in the *H2 Generation* sectors and as a competitive baseline in the distributed solar market for instance. If dynamic interaction with the *Electricity Demand* sector is expanded to occur individually for RCI consumers, these ratios will need to be refined, or perhaps dropped altogether.

6.6 Future Work

The current electricity sector does not simulate peculiarities within NZ's transmission grid system. Many grid nodes are surprisingly limited in transmission capacity, most notably the Cook Strait cable, through which all inter-island power transfer occurs. In the current model the grid is not capacity constrained. Maintenance and expansion of the grid occurs in pace with growing demand at no additional cost to the various consumers of electricity. All transfers of power from central generator to the end user are considered to occur at the network efficiency given above (independent of the power's source or destination region). Certainly, other NZ organizations have existing models of the

[34] "Briefing to the Incoming Government," Electricity Commission (2005), vol., Section 11.
[35] Energy Data File, Table I.2.
[36] Energy Data File.

complexities of the grid system, and future versions of this model should incorporate their findings. Hydrogen generation will also stress the grid in unforeseen ways; by better characterizing it in future versions of the model, the extent of those stresses can be understood.

The aggregation of various plants into super-plants for each region is a convenient way to pare down the complexity within New Zealand's system. However, individual plants contain their own economics, age, and efficiency—and each affects the plant's optimal electricity sell price. By aggregating, many of these differences are ignored, and this can result in an over- or under- estimate of cost and capacity. Similarly, the current model entirely removes the behavioural tendencies of the various enterprises currently invested in the industry. Each corporation has its own level of indebtedness and access to capital hindering or helping it in its role in the market. Thus the simple "My plant can beat the predicted future price" logic used to build new plants in the future central electricity generating sectors needs revision, as it invokes no capital constraints.

The inability of Stella to do simultaneous equation solving means prices always lag the changing make-up of demand and supply. Electricity is over-produced by 0.1 to 0.5 PJ's a year on average. In some ways, this imperfection is a good model of NZ's spot market, but occurs coincidentally rather than by design.

Finally, the system of finding average retail prices within each region and using ratios to get sectoral prices can be improved. RCI consumers see different electricity prices because they pay and receive their electricity in different ways. Many industrial consumers get power directly from the transmission network, or even immediately from on-site power plants. Thus they can avoid the regional distribution companies' higher tariffs. Similarly, residential rates are normally higher because of NZ's low population density and the high cost of sending power to remote areas. To accurately represent the different electricity costs one needs to disaggregate NZ's electricity distribution and transmission networks and their associated tariffs. A simulation of the electricity market and better representation of the different utility and consumer stakeholders might be useful. There are numerous government publications surrounding transmission and distribution, and they should be sourced thoroughly to improve this area of the model.

7 Distributed Solar

The *Distributed Solar* sector attempts to predict the effect of rising retail electricity prices and a maturing photovoltaic solar-cell industry on centralised electricity generation. Power generated by solar panels is considered to be on-site and therefore is not de-rated by the inefficiencies of the grid.

7.1 **Roof-Integrated PV**

The solar installations modelled are building-integrated photovoltaic (PV) cells. When the model determines such installations are economically viable, they are installed with all new residential and commercial roofs. No retrograde installations on existing roofs occur in the model. The costs used were taken from the recent East Harbour Management Services report on renewable energy[37]. The rate at which these roofs are installed is tied to the construction rate of new buildings in the residential and commercial sectors. Construction rates of 1.3% per year for residences and 0.8% for businesses are sourced

[37] Sise, Ruffell and Purnomo, NZ Electricity Outlook: Dry Year Risk 2003/04-2006/07, p.147.

from data on dwelling growth in New Zealand over the past decade[38]. The percentage of residential and commercial buildings built with PVs depends on the cost differential between PV and retail electricity prices in each region, as shown in Figure 3.

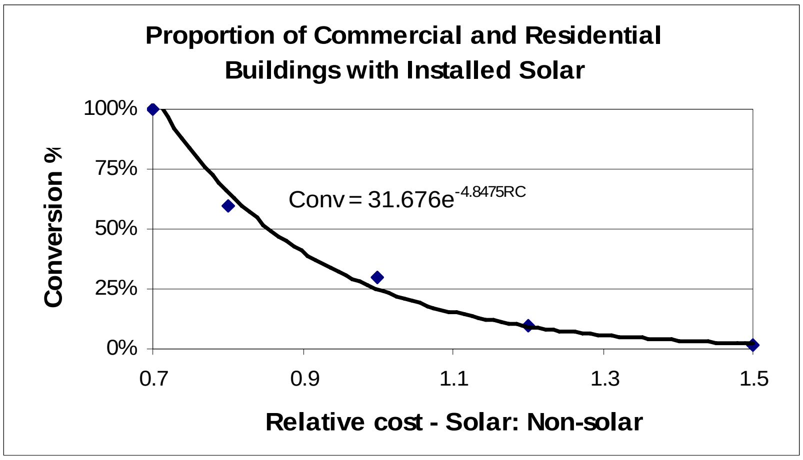

Figure 3: Solar Conversion Dynamics

PV electricity is projected to reduce in price from 42 c/kWh to 20 c/kWh by 2040[39,40] for on-grid electricity generation assuming a weighted average annual cost of capital (WACC) of 5% and an insolation value of 1500 kWh/m^2/y. The amount of energy generated by the roof-integrated PVs is expected to be equivalent to the household's on-grid electricity demand, which according to East Harbour Management Services is a reasonable assumption. However, these homes will still need to be on the grid to sell excess power on sunny days and buy power back at night. Once constructed, the PVs produce power for 25 years, the normal warranted life of commercial panels. If the modeller does not wish to model growth of distributed solar power, there is the option to shut it off with the *Ignore Solar* variable in the model Control Panel.

7.2 **Solar Thermal Water Heating**

Solar thermal water heating is demand-side management, because every solar thermal installation is one less electricity power water heater in use (at least when the sun is out). While there is very little solar thermal water heating currently in New Zealand, it nonetheless remains a potent future demand side management option. The model includes solar thermal among the various renewable options it builds in its Future Renewable Plant Construction sector. Supply curves are defined for solar thermal installations in each region, the slopes of which are determined both by the cost points in and average irradiance numbers for each region (see Table 7).

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[38] 2001 Census: Population and Dwelling Statistics (2001) - Reference Reports, 30 April 2002 2004, Website, Statistics New Zealand, Available: http://www.stats.govt.nz/domino/external/pasfull/pasfull.nsf/web/Reference+Reports+2001+Census:+Population+and+Dwelling+Statistics+2001, April 29 2004.

[39] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat (East Harbour Management Services, 2005), Table PV4.

[40] D.E. Carlson, The Status and Outlook for the Photovoltaics Industry, American Physical Society, Available: http://www.aps.org/meet/MAR06/, Nov. 1 2006.

Table 6: New Solar Thermal Resource[41]

c/kWh	GWh/y by 2025
9	350
<11	700
<13	800

All the future renewable supply curves are endogenous functions of the total number of installed GWh/y (which is abbreviated GWh_I) of production capacity for each particular technology. In this way, the model builds renewable technologies where they are best suited—e.g. sunny North facing slopes for solar thermal, or windy ridgelines for Wind—initially, and then turns to higher cost options later.

Table 7: New Solar Thermal Supply Curves by Region[42]

Region	Annual (kWh/m2/y)	% Population	Uptake Weighting Factor	Supply Curve (c/kWh)
Far North	1439	3.7	4%	0.2025*GWh_I + 6.09
Auckland	1564	32.2	34%	0.0238*GWh_I + 6.09
Waikato	1470	9.4	9%	0.0900*GWh_I + 6.09
Bay of Plenty	1533	6.3	7%	0.1157*GWh_I + 6.09
Taranaki	1533	2.6	3%	0.2700*GWh_I + 6.09
Central	1429	5.7	6%	0.1350*GWh_I + 6.09
Hawkes Bay	1512	4.8	5%	0.1620*GWh_I + 6.09
Wellington	1460	11.3	11%	0.07364*GWh_I + 6.09
Nelson/Marlborough	1502	4.0	4%	0.2025*GWh_I + 6.09
West Coast	1356	0.8	1%	0.8100*GWh_I + 6.09
Canterbury	1387	9.0	8%	0.1013*GWh_I + 6.09
South Canterbury	1491	4.0	4%	0.2025*GWh_I + 6.09
Otago/Southland	1189	7.1	6%	0.1350*GWh_I + 6.09
Total			100%	0.0081*GWh_I + 6.09

7.3 Future Work

The underlying numbers surrounding the technologies' predicted costs are rough estimates and a better assessment of roofing and reroofing trends in NZ would be informative.

8 Combined Heat and Power Plants

The *Cogen Generation* sector is another of the distributed electricity generation sectors. It represents the hundred or so businesses and industries generating power (and industrial heat) on-site. Co-generators in NZ use everything from industrial waste heat to geothermal springs and wood waste to generate electricity. All numbers used in this sector were gleaned from the EDF and the CAE "Electricity Supply and Demand to 2015" publications. The exact number of co-generators using specific fuels is not well documented in the literature.

[41] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table G11.
[42] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat.

8.1 Co-generator Grouping

The largest co-generators are shown in Table 8. In the model, co-generators produce power at rates predicted by the CAE[43] and do not respond to price signals. The power they produce is mostly consumed on-site, but for simplicity the model assumes all co-generation electricity production is used without running through the grid and suffering the associated efficiency losses.

Table 8: Co-generators

Cogen Plant Name	GWh/y
Edgecumbe	61
Kapuni	175
Glenbrook	494
Te Rapa	296
Te Awamutu	182
Kinleith	274
Hawera	228
Kawerau	271
Small NI	322

8.2 Energy Use

Co-generators burning coal and natural gas are assumed to have dual-fuel boilers. The total amount burned by the two fuels was taken from the EDF's energy balances[44]. In this way, a certain degree of fuel switching occurs automatically, as the cost effectiveness changes. This behaviour is entirely theoretical, and is not supported by historical evidence of fuel switching. It is an attempt to predict what may happen to co-generators as they face projected shortages of natural gas in the near future.

8.3 Distributed Micro-generation

There are 3 types of combined heat and power micro-generation units modelled in the *MicroResidential CHP* and *MicroCommercial CHP* sectors. The first two are residential units fed by either piped hydrogen or piped natural gas with a 0.6 kWe fuel cell that also produce 0.4 kWth of heat each. The third is a commercial unit that runs on piped hydrogen with a 250 kWe molten carbonate fuel cell that produces 167 kWth of heat. All the energy is assumed to be consumed at the site. The performance and cost data for these theoretical units was supplied by Industrial Research Ltd, New Zealand.

The key technical details for the 3 units are shown in Table 4 with learning curves shown in Figure 4.

Table 9:Technical details of microgeneration options.

Technology	Feedstock	Target Price 2015 ($NZ)	Annual Costs (Depr, O&M, Interest)	Life (y)
CHP 1 kW	Hydrogen	3,500	22.3%	10
CHP 1 kW	Natural Gas	5,300	22.3%	10
CHP 417 kW	Hydrogen	550,000	21.3%	15

[43] Brian Leyland and Steven Mountain, Electricity Supply & Demand to 2015, 6th ed. (Sinclair Knight Merz and CAE, 2002) Appendix 1.
[44] Energy Data File, Table B.2g, p.26.

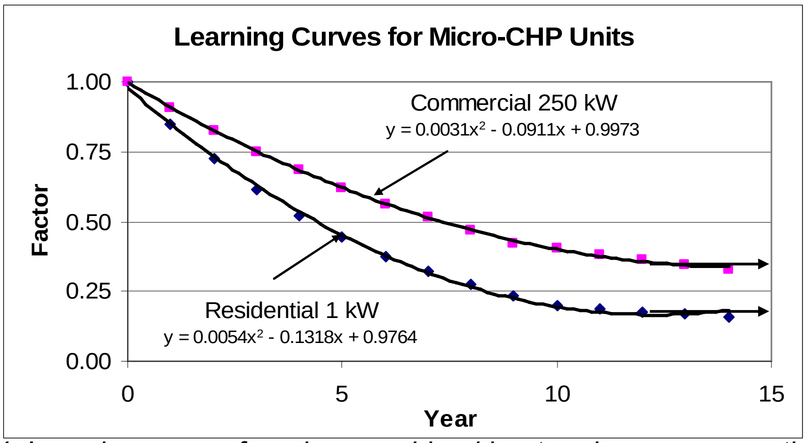

Figure 4: Learning curves for micro combined heat and power generation.

Model dynamics dictate that new technologies are not retrofitted. Hence even when a residential generation option is most viable the growth rate is limited to the growth rate of new construction.

8.4 Future Work

Further research should be done into the fuelling possibilities facing large scale co-generators, the amount of electricity they use on-site versus sell back to the grid, the type of energy contracts they sign, and the potential for future growth. Even a survey of the large scale co-generators that linked plants, names and fuel types would be a great benefit, as currently the modelled generation is entirely disconnected from the feedstock energy source, risking the legitimacy of the model's energy balance. In the absence of additional information the model assumes a no-growth scenario for this sector. An improvement would be to have co-generation development instead respond to price signals or follow growth trends.

For the purposes of this contract the model operates on weekly time steps and hence the daily electricity profile with its associated peaks is not modelled. For microgeneration of combined heat and power this limitation restricts viability as costs are compared on the weekly average electricity price. Further modelling using 2 hour time steps and including the daily electricity profile in the model could enhance the uptake of microgeneration.

9 Hydro Generation

The *Hydro Generation* sector, like all the following existing central electricity generation sectors, incorporates existing, currently planned, and future plant data. The key components in each of these sectors are four arrays broken down by region: existing plant capacities (in GWh/y), future plant capacities, cost of electricity produced by existing plants (in cents/kWh), and the costs of electricity produced by future plants. The future plant capacities and costs are determined endogenously by the model in *Future Fossil Generation Costs, Future Electricity Plant Construction,* and *Fossil Plant Siting* sectors, all of which will be discussed later.

Using the aggregate capacity numbers for each region, each sector calculates a regional potential generation that it sends to the *Wholesale Price Calculation.* This number is a measure of the maximum energy the sector can generate per year. In some sectors, this potential can be limited by fuel availability, such as in the *Gas Generation* sector. Specific to the *Hydro Generation sector*, the energy output of a region may be limited by resource consents or simply the amount of rainfall.

Each sector also calculates the amount of electricity it is willing to produce at the various wholesale spot prices in the *Wholesale Price Calculation* (see Section 6.3). For renewable sectors (geothermal, wind, biomass…) this amount doesn't change much, but fossil generators' supply curve is directly affected by fuel prices and changing carbon taxes.

9.1 Current and Future Pricing

In the Hydro Generation sector*, the price of wholesale electricity produced at existing plants is assumed to be 1 c/kWh. The existing plants and their associated plant factors included in the model are shown in Table 12. The cost of electricity from potential future hydropower plants, however, is much higher, as seen in Table 10 and Table 11.*

Table 10: New Hydropower Generation Potential by Region[45,46]

Year	Location	MW	GWh/y	Region	Estimated c/kWh	Cum GWh/y
2019	Whirinaki River	25	110	Bay of Plenty	9.2	110
2015	Hurunui Lowry Peak	36	160	Canterbury	8.1	160
2017	Clarence/Waiau Div	70	300	Canterbury	8.5	460
2020	Lower Waiau	50	220	Canterbury	9.4	680
2023	Upper Waiau	56	240	Canterbury	10.4	920
2024	Mid Waiau	60	270	Canterbury	10.9	1190
2024	Mangawhero Div	60	260	Central	10.8	260
2019	Ngaruroro scheme	134	585	Hawke's Bay	8.9	585
2024	Mohaka	75	330	Hawke's Bay	11	915
2014	Wairau	70	415	Nelson/Marlborough	7.4	415
2004	Manapouri	25	158	Otago/Southland	6	158
2005	Manapouri	16	105	Otago/Southland	6.3	263
2019	Te Anau Gates	65	350	Otago/Southland	9.1	613
2021	Nevis River	45	197	Otago/Southland	9.9	810
2020	Pukaki Canal Intake	44	120	South Canterbury	9.5	120
2022	Lower Waitaki	260	1,500	South Canterbury	10.3	1620
2013	Lower Grey River	210	920	West Coast	7.1	920
2018	Upper Grey Scheme	70	307	West Coast	8.6	1227
2019	Rough River	11	49	West Coast	9	1276

The supply curves employed are derived from Table H7 and 16 from the 2005 East Harbour Management Services report on renewable potential in New Zealand. Resource potential is assessed at WACC of 10% with high confidence as pressure from agricultural, horticultural and recreational users is predicted to increase in the future. Regions omitted are considered to not have any practical future hydropower resources. Hard limits to installed capacities are placed, simply because there are a finite number of many potential dam sites.

[45] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table H7.
[46] Initial Statement of Opportunities, Table 16.

Table 11: New Hydropower Plant Supply Curves by Region[47]

Region	Supply Curve (c/kWh)	Generation Limit (GWh/y)
Bay of Plenty	9.2	110
Hawkes Bay	0.0064*GWh_I+5.177	585
Nelson/Marlborough	7.4	415
Canterbury	0.0004*GWh_I+7.711	680
West Coast	0.0052*GWh_I+2.326	1276
South Canterbury	0.0005*GWh_I+9.436	1620
Otago/Southland	0.0064*GWh_I+4.863	810

Table 12: Existing Hydropower Plant Data

Name	Plant Factor[48]	MW[49]	Name	Plant Factor	MW
North Island			*South Island*		
Aniwhenua	0.95	25	Opuha	0.95	7
Waihi	0.95	5	Clyde	0.95	432
Kourarau	0.95	1	Roxburgh	0.89	320
Rangipo	0.97	120	Aviemore	0.90	220
Tokaanu	0.98	210	Benmore	0.97	540
Waikaremoana	0.95	135	Manapouri	0.86	760
Kuratau	0.95	6	Ohau_A	0.95	248
Mangahao	0.60	38	Ohau_B	0.95	212
Piriaka	0.95	1	Ohau_C	0.95	212
Wairere Falls & Mokauiti	0.95	7	Tekapo_A	0.83	25
Arapuni	0.90	175	Tekapo_B	0.93	160
Aratiatia	0.96	84	Waitaki	0.84	105
Atiamuri	0.91	79	Fox, Turnbull & Okuru	0.95	2
Karapiro	0.97	96	Glenorchy, Wye, Meg, Fraser	0.95	8
Maraetai	0.97	360	Teviot (4 Stations)	0.95	11
Ohakuri	0.99	112	Horseshoe Bend	0.95	4
Waipapa	0.95	51	Cobb	0.89	32
Whakamaru	0.96	100	Arnold	0.95	3
Opunake & Raetihi	0.95	1	Coleridge	0.95	35
Wairua	0.95	3	Highbank	0.95	25
Hinemaiaia	0.95	7	Monowai	0.95	6
Kaimai Hydro	0.99	45	Montalto	0.95	2
Mangorei & Motukawa	0.95	9	Paerau & Patearoa	0.98	12
Matahina	0.91	72	Waihopai & Branch	0.95	12
Patea	0.99	33	Waipori	0.26	81
Wheao/Flaxy	0.99	26	West Coast Hydro (7 stns)	0.95	12

[47] Ibid.
[48] Energy Data File, Table G.7a, p. 108. For those plants without data, plant factor set to .95.
[49] Leyland and Mountain, Electricity Supply & Demand to 2015 Appendix 2.

9.2 **Rainfall**

The modeller may choose the *Random Rainfall* variable to switch between simulated random seasonal changes in rainfall or an average year. The simulated seasonal changes pick from a normal distribution of rainfall four times a year, using smoothing algorithms to accomplish even transitions. The average hydro year, on the other hand, is assembled by looking at the monthly mean flow at 30 dams across New Zealand since 1931.

9.3 **Future Work**

As mentioned previously in the *Wholesale Price Calculation* discussion, data for the centralised electricity generators is aggregated to a regional level. All of the following sectors could benefit from more data surrounding the capital concerns of the owners of the various generation facilities. The hydro sector, as one of the largest and most important, should include more detailed modelling of costs of generation and rainfall. Currently, the model has a simple at best inflow simulator. An understanding of how the rainfall inflow system works should be applied in future versions of the model.

Also, the current version of the model does not simulate efficiency improvements at in situ at existing plants, something that likely will happen. The efficiency potential of the various plant types should be researched and included in future versions.

10 Wind Generation

The basics of this sector are discussed in the *Hydro Generation* sector. Existing wind plants are intermittent, and so they bid into the wholesale market at 3c/kWh, well below the cost of the marginal natural gas and coal-fired power producers. Plant factors and capacities for existing and planned wind farms are shown in Table 13.

Table 13: Existing Wind Farm Data

Wind Farm Name	Plant Factor[50]	MW[51]
Existing		
Hau_Nui	0.45	3.5
Wellington	0.57	0.2
Tararua	0.48	68
Te Apiti	0.45	91
Planned		
Tararua III	0.45	93 in 2007
West Wind	0.45	210 in 2008
White Hill	0.45	58 in 2007
Te Rere Hau	0.45	49 in 2007
Awhitu*	0.45	18 in 2008
Te Pohue	0.45	225 in 2008
Titiokura	0.45	48 in 2008

*Likely project delay beyond 2008.

Supply curves for future wind farms are calculated from a correlation of wind potential at a national level for WACC of 10% and capital expenditure of $1800/kW.[52] The national

[50] Energy Data File, Table G.7a, p. 108. For those plants without data, plant factor set to .45.
[51] Energy Data File, Table G.7a, p. 108.

correlation is shown in Figure 5, with regional resource[53] estimates and costs[54] in Table 14 coming from East Harbour Management Services (EHMS) 2005 report. The national supply curve is fitted to each region's resource estimate and cost to come up with the regional supply curves shown in Table 15, A "learning by doing" factor, or new plant price reduction, of 1.8% per year from 2005,[55] is applied to the regional supply curves.

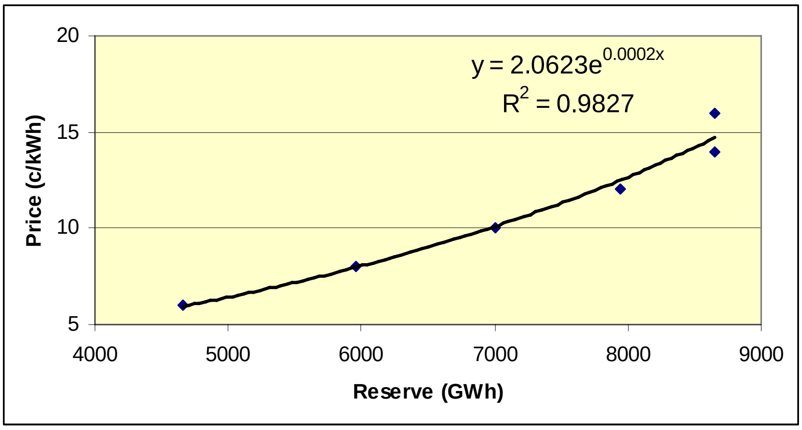

Figure 5: New Wind Farm Supply Curve (National)[56]

Table 14: New Wind Farm Resource Estimate by Region

Region	Typical wind speed in m/s at 50 mAGL	Area (km2)	MW	GWh/y	Proportion of total	Estimated Electricity Price (c/kWh)
Far North	8	38	382	1167	12.4%	8.2
Northland (S-W)	8	3	33	98	1.0%	8.2
Auckland	8	2	22	76	0.8%	8.2
Waikato West	8	3	33	98	1.0%	8.2
Waikato East	9	4	44	153	1.6%	6.8
Taranaki	7	33	327	775	8.2%	9.5
Central	10	11	109	447	4.7%	5.5
Central East	8	7	65	201	2.1%	8.2
Hawkes Bay	8	26	262	803	8.5%	8.2
Wellington	9.5	60	600	2302	24.4%	6.2
Nelson/Marlborough	8	9	87	273	2.9%	8.2
Canterbury	7.5	24	240	644	6.8%	8.8
Otago/Southland	7	71	709	2411	25.5%	9.5

52 Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat.
53 Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table W.2.
54 Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table W.4.
55 Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat.
56 Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat.

Table 15: New Wind Farm Supply Curves by Region

Region	Regional fraction of total generation at minimum cost	Supply Curve (c/kWh)	Minimum Cost (c/kWh)
Far North	0.134	$GWh\_I * 2.0623e^{0.00149}$	8.2
Auckland	0.008	$GWh\_I * 2.0623e^{0.02500}$	8.2
Waikato	0.026	$GWh\_I * 2.0623e^{0.00769}$	8.2
Taranaki	0.082	$GWh\_I * 2.0623e^{0.00244}$	9.5
Central	0.069	$GWh\_I * 2.0623e^{0.00290}$	5.5
Hawkes Bay	0.085	$GWh\_I * 2.0623e^{0.00235}$	8.2
Wellington	0.244	$GWh\_I * 2.0623e^{0.00082}$	6.2
Nelson/Marlborough	0.029	$GWh\_I * 2.0623e^{0.00690}$	8.2
Canterbury	0.051	$GWh\_I * 2.0623e^{0.00392}$	8.8
South Canterbury	0.017	$GWh\_I * 2.0623e^{0.01176}$	9.5
Otago/Southland	0.255	$GWh\_I*2.0623e^{0.00078}$	9.5

Table 16: Existing Geothermal Plant Data

Plant Name	Plant Factor[57]	MW[58]
Existing		
TOI & TG2, Kawerau	0.82	6
McLachlan/Poihipi	0.5	55
Ohaaki	0.75	35
Wairakei	0.94	179
Mokai	0.79	65
Ngawha Springs	0.91	11
Rotokawa	0.94	32
Planned		
Te Mihi	0.9	18 in 2008
Poihipi Road	0.9	25 in 2009
Kawerau II	0.9	70 in 2008
Ngawha II	0.9	15 in 2008

11 Geothermal Generation

The basics of this sector are discussed in the *Hydro Generation* sector. Geothermal plants are assumed to emit ¼ the amount of CO_2 of a new natural gas combined cycle (NGCC) plant.[59] Existing geothermal plants provide electricity at an aggregate 2 c/kWh, but future facilities have much higher supply costs (Table 19). Plant factors and capacities for existing and planned geothermal plants are shown in Table 16.

Beyond the planned horizon, future geothermal generation is assumed to be restricted to Waikato and Bay of Plenty regions, with the Bay of Plenty having roughly 44% of the remaining resource (see Table 17 and Table 18). Geothermal resource potential is based on EHMS medium confidence levels with WACC of 10%,[60] with hard regional limits to geothermal development similar to that on future hydropower dam development.

[57] Energy Data File, Table G.7a, p. 108. For those plants without data, plant factor set to .9.
[58] Energy Data File, Table G.7a, p. 108.
[59] Jim Lawless, New Zealand Geothermal Association Submission on Climate Change Consultation Paper (Auckland, New Zealand: New Zealand Geothermal Association Inc, 2001).
[60] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table G11.

Table 17: Potential Future Geothermal Projects by Region[61]

Year	Name	MW	GWH/yr	Region
2005	Wairakei Extension	14	118	Waikato
2010	Kawerau	150	1,200	Bay of Plenty
2013	Kawerau	100	800	Bay of Plenty
2015	Rotoma	40	330	Bay of Plenty
2016	Rotokawa II	150	1,200	Waikato
2016	Wairakei	180	1,400	Waikato
2021	Atiamuri	50	400	Bay of Plenty
2021	Horohoro	40	330	Bay of Plenty
2021	Mangakino	40	330	Waikato
2022	Mokai III	100	800	Waikato
2022	Pohipi	20	150	Waikato
2024	Kawerau	50	400	Bay of Plenty
2024	Rotokawa III	150	200	Waikato
2024	Tauhara	50	180	Waikato
	Total		7,838	

Table 18: New Geothermal Resource[62]

c/kWh	GWh/y by 2025
3	200
<5	3512
<7	7100
<9	7439

Table 19: New Geothermal Plant Supply Curves by Region

Region	Supply Curve (c/kWh)	Generation Limit (GWh/y)
Bay of Plenty	0.00160*GWh_I + 2.6868	3,273
Waikato	0.00125*GWh_I + 2.6868	4,166

12 Biomass/Waste Gas Generation

The basics of this sector, includes landfill gas plants and future biomass-based electricity generation plants, are discussed in the Hydro Generation sector. Existing landfill gas plants are assumed to have a cost of generation of about 6 c/kWh. Existing plant data is shown in Table 20. Biogas use efficiency is assumed to be 30%.[63]

[61] Initial Statement of Opportunities, Table 16.
[62] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table G11.
[63] Energy Data File, p.13.

Table 20. Waste Gas Plant Data

Waste Gas Plant Name	Plant Factor[64]	MW[65]
Rosedale/Greenmount	0.85	8
Silverstream	0.85	3

No future landfill gas plants are modelled however biomass (forest arisings, sawdust, etc.) has proven electricity potential. Electricity potential is determined at a 10% WACC reflecting the return required from corporate users and a medium confidence level (see Table 21). This resource assessment is fitted to a national new biomass electricity supply curve, *Price (c/kWh) = (.0047*GWH_I + 7.5027).* This national supply curve is then fitted to the regional biomass assessment to create region-specific biomass supply curve slopes (Table 22).

Table 21: New Biomass Resource Assessment[66]

Supply Cost (c/kWh)	Electricity (GWh/y)	Total (GWh/y)
<9	285	285
<11	425	710
<13	705	1415

Table 22: New Biomass Supply and Supply Curves by Region[67]

Region	(km^3y) 2011-2015	(km^3y) 2021-2025	Average Proportion	Supply Curve Slope (c/GWH_I)
Far North	4206	4200	0.120	0.0392
Auckland	948	1073	0.029	0.1621
Waikato	3000	3000	0.086	0.0547
Bay of Plenty	8586	9398	0.256	0.0184
Central	1394	3695	0.073	0.0644
Hawkes Bay	5170	7516	0.181	0.0260
Wellington	1000	1000	0.029	0.1621
Nelson/Marlborough	2874	3362	0.089	0.0528
West Coast	387	385	0.011	0.4273
Canterbury	1000	1200	0.031	0.1516
South Canterbury	254	488	0.011	0.4273
Otago/Southland	2461	3578	0.086	0.0547
Total	31280	38895	1	0.0047

In the future, East Harbour Management Services predicts a 35% reduction in biomass gasification technology over the next 24 years i.e. a 1.3% "learning by doing" factor[68]. This factor is applied to the regional supply curves by the model.

[64] Energy Data File, Table G.7a, p. 108. For those plants without data, plant factor set to .95.
[65] Leyland and Mountain, Electricity Supply & Demand to 2015 Appendix 2.
[66] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table BMW10, Table BMW11.
[67] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Table BMW1.
[68] Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, Figure BMW2.

13 Fossil Fuelled Generation

13.1 Gas and Coal Generation Sectors

The basics of the *Gas Generation* and *Coal Generation* sectors are discussed in the *Hydro Generation* sector. The gas generation sector assumes Huntly is devoted solely to coal because of natural gas shortages. In both the *Gas Generation* and *Coal Generation* sectors thermal efficiency is based on the fuel's higher heating value. Also, these two sectors share their method of wholesale price calculation for existing plants, which is made up of the cost of fuel and capital along with the carbon tax and profit. Capital and profit are estimated to approximate the gas and coal prices available in the literature. These should be refined plant by plant according to the economic standing of the owning utilities. Both sectors, as mentioned previously, would benefit from further disaggregation and dynamic fossil fuel bidding/contract processes.

Unique to the *Gas Generation* sector is the check for availability of natural gas for existing generators during each time step. This "check" would be unnecessary if the model contained a better functioning natural gas market. Currently the system works reliably. The capital and profit component of electricity production from existing natural gas plants is assumed to be 2 c/kWh. Plant data is shown in Table 23. Gas use efficiency, in aggregate is assumed to be 40%.[69]

Table 23. Gas Plant Data

Gas Plant Name	Plant Factor[70]	MW[71]
New Plymouth	0.69	400
Huntly: All Coal	0.9	-
Southdown	0.95	118
Stratford Power CC	0.9	354
Otahuhu B	0.95	365
Huntly-e3P	0.9	385

Huntly is the only existing plant included in the *Coal Generation* sector, with a total capacity of 1 GW and plant factor of 0.9. Coal use efficiency is assumed to be 33%[72], with profit of 4 c/kWh.

13.2 Future Gas and Coal Plant Costs

The *Future Fossil Generation Costs* sector determines the availability and electricity costs of new plants of different fossil technologies in each region. It models two types of coal plants, pulverised coal bed and integrated gasification combined cycle (IGCC). The IGCC coal plant type is further broken down into carbon-emitting and carbon-sequestering plants. The sector also includes natural gas combined cycle (NGCC) plants with and without carbon-sequestration.

All data surrounding the electricity cost calculations in this sector come from MIT's "The Cost of Carbon Capture" paper (Table 24).[73] The paper includes current and projected values (in 2012) for operating and maintenance (O&M) and fixed costs and the thermal

[69] Energy Data File, p. 13.
[70] Energy Data File, Table G.7a, p. 108. For those plants without data, plant factor set to .95.
[71] Leyland and Mountain, Electricity Supply & Demand to 2015 Appendix 2.
[72] Energy Data File, p. 13.
[73] Howard Herzog and Jeremy David, "The Cost of Carbon Capture," Fifth International Conference on Greenhouse Gas Control Technologies (Cairns, Australia: 2000), vol.

efficiencies of the various plant types. The numbers are incorporated as is, except for the thermal efficiencies, which were converted from a lower heating value (LHV) to a higher heating value (HHV) basis. Plants that sequester carbon pay for every tonne they sequester. They also pay carbon taxes on the remaining mass of CO_2 they emit. The model chooses to build capture or non-capture plants depending on carbon tax and sequestration economics. All cost, efficiency, and carbon emission numbers are independent of region.

13.3 **Future Gas and Coal Plant Availability by Region**

First of all, future gas plants are only built if the model is an LNG run. This is because dwindling domestic natural gas supplies alone do not afford enough gas for a new gas turbine to assure supply. Secondly, large fossil electricity generators may not be suitable for certain regions at all because of social, recreational, environmental and other concerns. This determines whether a fossil plant of any type is allowed in the region.

Table 24: Future Coal and Gas Plants, with CO2 Capture

Cycle	IGCC		PC		NGCC	
Data Description	**2000**	**2012**	**2000**	**2012**	**2000**	**2012**
Reference Plant						
CO2 Emitted, kg/kWh	0.752	0.664	0.789	0.766	0.368	0.337
Cost of electricity (coe):						
CAPITAL (¢/kWh)	3.2	2.61	2.63	2.5	1.24	1.2
coe: FUEL (¢/kWh)	1.00	0.88	1.03	1.00	1.82	1.66
coe: O&M (¢/kWh)	0.79	0.61	0.74	0.61	0.25	0.24
coe: Total (¢/kWh)	4.99	4.10	4.39	4.10	3.30	3.10
Thermal Efficiency -LHV (%)	42.2	47.8	41.2	42.4	55.0	60.1
Capture Plant						
Relative Power Output, %	85.4	91.0	75.0	85.0	87.0	90.0
coe: CAPITAL (¢/kWh)	4.36	3.33	4.77	3.92	2.31	2.04
coe: FUEL (¢/kWh)	1.17	0.97	1.37	1.17	2.09	1.85
coe: O&M (¢/kWh)	1.16	0.84	1.57	1.16	0.51	0.44
coe: Total (¢/kWh)	6.69	5.14	7.71	6.25	4.91	4.33
Thermal Efficiency -LHV (%)	36.1	43.5	30.9	36.1	47.8	54.1

Next, natural gas plants can only be built in those regions with high pressure gas pipelines (see Table 25). Finally carbon sequestering plants will only be placed when there is an imposed carbon tax and where sequestration costs are low enough to be financially viable (for more on carbon sequestration see section 25.2).

13.4 **Which Plant and When**

As the model runs, electricity demand grows and, without new electricity production, wholesale prices would rise proportionately to the tight supply. For fossil generators, whenever electricity supplies are tight and there is less than a 10% generation buffer, the model considers building new fossil plants subject to their availability as discussed in section 13.3 and a few limitations. All the simulation described in the paragraphs below occurs in the *Fossil Plant Siting* and *Future Electricity Plant Construction* sectors.

Table 25: Availability of Fossil Plant by Characteristic

Region	Fossil allowed	High Pressure Gas
Far North	Yes	No
Auckland	No	Yes
Waikato	Yes	Yes
Bay of Plenty	No	Yes
Central	Yes	Yes
Hawkes Bay	Yes	Yes
Wellington	Yes	Yes
Nelson/Marlborough	No	No
West Coast	Yes	No
Canterbury	No	No
South Canterbury	Yes	No
Otago/Southland	Yes	No
Taranaki	Yes	Yes

First, the model determines the optimal region available for each plant type, which is the region with the most expensive retail prices (i.e. where the greatest potential profit margin resides). Next, the model determines the optimal technology available in each region, which is the technology available that produces electricity at the lowest supply price. Finally, for each region, if: a) there is not already a plant under construction and b) the optimal technology has a production cost below the *Capital Planning Wholesale Price* of electricity, a plant of that technology type will be built.

Key to the build decision is the *Capital Planning Wholesale Price*, which is defined as a 4 year price future based on the national wholesale spot price, scaled by 10% / (current *Generation Buffer*). In this way, when there is adequate supply, no plants are built, because the current generation buffer is larger than 10% and the futures market is scaled down. When supplies are tight, the futures market is scaled highly, encouraging new plants.

Construction times and plant sizes for the technologies modelled shown in Table 26 are educated guesses. Sequestration plants are considered to take longer to build, to have larger generating capacity and be more capital intensive. Future research should be undertaken to refine these numbers. Extensions to the model should incorporate more educated plant-size decision-making.

Table 26: Fossil Plant Construction and Sizes

Plant Type	Construction Time (Yrs)	Plant Size (MW)
Integrated Gas Combined Cycle (IGCC)	4	500
IGCC Capture	5	600
Pulverised Coal (PC)	3.5	400
Natural Gas Combined Cycle (NGCC)	2.5	200
NGCC Capture	3.5	400

13.5 Future Work

Profitability depends not only on the price obtained in the wholesale market for the marginal kWh produced, but also on plant factor. This second dependency is absent in the model and should be added in future versions.

The model aims to approximately replicate the investment decisions of power generators. This is accomplished by the model identifying the need for more generation and then fulfilling the need by choosing the cheapest source. This choice is made irrespective of availability of necessary capital inflows in the private sector—in effect assuming unlimited access to capital. This may be a reasonable approximation as long as overseas capital flows into New Zealand are available for generation investments. Future work could examine the reasonableness of this assumption and possibly model capital constraints that could limit investment in very large generation facilities.

14 Future Renewable Plant Construction

Future renewable plants are built within the model similar to the method discussed above, with minor differences to be described next.

14.1 Which Plant and When

First, the model builds renewable plants steadily throughout the model run, at a rate determined by a variety of run time variables. In other words, more than one facility can be constructed in a particular region at once. This is sensible, because renewable technologies are easily scalable and rarely built in the 100s of MW.

Instead of using the *Capital Planning Wholesale Price*, a renewable plant of type (technology, region) will only be built when it can produce electricity cheaper than 90% of the national wholesale price. This is to ensure that “must-run” renewable technologies are not priced out of the spot-market. The rate new capacity is constructed is limited to no greater than 10% of the total renewable resource of the type (technology, region) per year. Construction times are shown in Table 27.

The electricity supply price of newly constructed renewable plants of type (technology, region) is determined by the cumulative amount of GWh/y capacity constructed of type (technology, region), according to supply curves and learning rates laid out earlier in this document.

Table 27: Renewable Plant Construction and Sizes

Plant Type	Construction Time (Yrs)
Wind	4
Hydro	4
Geothermal	3
Biomass	3
Solar Thermal	0.5

14.2 Future Work

Using a simple construction time is misleading, because renewable energy projects can be delayed by the resource consent process. Some stochastic delay time might be better. There are many creative ways to make this sector more realistic and dynamic, and future modellers should focus a good deal of effort to do so, as it plays a very pivotal role in the rest of the electricity and hydrogen market.

15 Socio-Political Indicators

The *Socio-Political Indicators* sector contains essential parameters relating to how the economy changes over time. In particular it includes the key exogenously defined population and GDP parameters. Population growth is based on predictions by Statistics New Zealand.[74] GDP grows uninhibited at 2.5%, which many government publications consider base case growth for the near term.

The loss willingness and NZ to US dollar exchange rate are also included in this sector, although they are designed to be modified on the Control Panel.

15.1 Future Work

GDP is exogenously defined, and GDP scenarios could usefully be included. GDP can be linked with population growth (higher GDP means more immigration), energy prices (increases in energy costs can slow GDP growth), and vehicular behaviour. GDP increases imply personal wealth increases, affecting the numbers and sizes of vehicles and vehicle kilometres driven. Including these factors in the model will require substantial changes, and should accompany the addition of domestic and international capital stock and flows.

Finally, the current model could also include links to broader economic indicators such as the current account balance, type and value of exports and imports. Policymakers interested in knowing the economic impact of, say, subsidizing the introduction of a hydrogen economy, would be able to determine effects within the energy sector.

16 Vehicle Fleets

The *Vehicle Fleets* sector of the model determines the evolution of each of the vehicle fleets over time. This sector also includes two model variables, *Model H2?* and *Model EV?*, which allow the modeller to quickly and easily simulate the energy economy without hydrogen and electric vehicles respectively. These are useful to develop a reference scenario.

16.1 Vehicle Fleet Groupings

Key to the transport model is a breakdown of the fleets. There are fifteen fleets modelled as shown in Table 28.

The first distinction is between the ICE vehicles, HFCVs, and EVs. Each of these fleets is then divided into the light and heavy vehicle fleets. For the ICE fleet, a “light vehicle” is considered to be a car with 110 kW engine using petrol as fuel. A “heavy vehicle” is a vehicle that weighs more than 3.5 tonnes with the average heavy vehicle modelled as a 6 tonne diesel truck with an average engine power of 220 kW (double that of a light vehicle).

[74] Vasisht, Profile of New Zealand Motor Vehicle Fleet.

Table 28: Vehicle Fleet Groupings

ICE Vehicles (H_2&Pet/Diesel)	Light	Imported Used	
		New	
	Heavy		
HFCVs	Light	Imported Used	North South
		New	North South
	Heavy		North South
EVs	Light	Imported Used	North South
		New	North South
	Heavy		North South

For the HFCV and EV fleets a "light vehicle" corresponds to a vehicle with a 73 kW engine that runs on hydrogen or electricity respectively. A figure of 73 kW is assumed since an electric motor need only be 2/3 of the size of an internal combustion motor to provide the same torque—and thus the same performance. It is anticipated that manufacturers of HFCVs and EVs will aim to match the vehicle performance of ICE vehicles. A "heavy vehicle" for the HFCV and EV fleets is modelled as a 6 tonne truck with an average engine power of 146 kW that runs on hydrogen or electricity respectively. The distinction between light and heavy vehicles may seem somewhat arbitrary, but when modelling the consumer decision-making process between HFCVs, EVs and ICEs, an aggregated approach such as this offers the highest degree of clarity.

In New Zealand, 66% of light petrol vehicles are purchased as used imports, mainly from Japan, with the remainder being light vehicles imported brand-new.[75] Thus, the imported used fleet is separately modelled from the new fleet for light vehicles. Heavy vehicles are not differentiated into a new and imported fleet. It is assumed that light hydrogen and electric vehicles will also be imported used and thus we break down the HFCV and EV fleets into the imported used and new fleets.

Finally, while developing the model, it was determined the two islands of New Zealand offer different resources and challenges to purveyors of hydrogen, and thus they are truly isolated markets with different price signals. Fleets are designated accordingly. The regional population percentage defines the size of the market on each Island, assuming that vehicles per capita statistics are uniform throughout the nation.

16.2 **Evolution of Vehicle Fleets**

The evolution of the 15 vehicle fleets (one in each of 13 regions and one in each Island) over time is governed first by an assumed increase in the number of light imported used, light new, and heavy vehicles on each island. This follows the reasonable assumption that total fleet growth is limited by the population growth. Specifically, the total vehicle fleet is expected to continue growing at the average annual rates seen in the past

[75] New Zealand Motor Vehicle Registration Statistics 2005 (Parlmerston North: Land Transport New Zealand, 2006).

decade[76] of 2.07% per annum for light vehicles and 2.03% per annum for heavy vehicles until the *Vehicles Per Capita* indicators approach levels currently seen in the United States,[77] 0.6 per capita for light vehicles and 0.15 per capita for heavy vehicles. In other words, the entire light vehicle fleet composed of internal combustion engined vehicles (ICEVs), hydrogen fuelled ICEVs (HICEVs), hydrogen fuel cell vehicles (HFCVs), and electric vehicles (EVs) for both imported used and new vehicles, grows at a rate of 2.07% per annum while the commensurate heavy vehicles fleet grows at a rate of 2.03% per annum until the *Vehicles Per* Capita constraint becomes binding.

Once the fleet growth of the light imported used, light new, and heavy vehicle fleets are each determined, the model then has the task of allocating these fleets between ICEVs, HICEVs, HFCVs, and EVs. This is accomplished by modelling the consumer vehicle-buying decision-making process. To simplify the decision-making process, consumers are assumed to decide which vehicle to purchase based on two factors: (1) the annualised cost of owning and operating the vehicle in a specific region for one year and (2) their intrinsic preference for one vehicle type over another. This intrinsic preference captures consumers' factoring in of considerations such as the availability of refuelling infrastructure, the "green image" of the vehicles, and quiet performance.

The mathematical structure used to model this decision-making process is called a logit (vehicle) choice model. It is a well-known technique widely used throughout the economics literature and in fact has been used to model the introduction of advanced vehicles into a vehicle fleet.[78] The logit constitutes two parameters that govern the relative attractiveness of one item (e.g., an ICE vehicle) over another (e.g., a HFCV). The first parameter is a price elasticity that determines how much demand adjusts to change in price, where the price in this case is the annualised cost of owning and operating the vehicle. The second parameter is the intrinsic preference parameter described above.

A standard logit choice model, as is used here, gives the market share of item 1 as a function of the price of item 1 (p_1), the price elasticity for item 1 (β_1), and the intrinsic preference parameter for item 1 (γ_1) as follows:

$$share_1 = \frac{exp(\beta_1 p_1 - \gamma_1)}{\sum_i exp(\beta_i p_i - \gamma_i)}$$

The price elasticity in this case refers specifically to the long-run elasticity of demand for new vehicles with respect to the annual cost of owning and using the vehicle. While there is no literature that exactly estimates this coefficient, the long-run elasticity for new cars with respect to the price of the cars (as opposed to the annual cost of owning and using the car) is commonly considered to be close to -.05.[79] This estimate seems reasonable as well for the elasticity of demand for new cars with respect to the annual cost and is hence used in the model (with the negative sign dropped).

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[76] Vasisht, Profile of New Zealand Motor Vehicle Fleet, pp.8,10.
[77] The Dynamics of Energy Efficiency Trends in New Zealand: A Compendium of Energy End-Use Analysis and Statistics, (Wellington, NZ: Energy Efficiency and Conservation Authority, 2000) Fig 4.1a,b, p. 62.
[78] D.J. Santini and A.D.Vyas, Suggestions for a New Vehicle Choice Model Simulating Advanced Vehicles Introduction Decisions (Avid): Structure and Coefficients (Center for Transportation Research Argonne National Laboratory, 2005).
[79] R. Pindyck and D. Rubinfeld, Microeconomics, 4th Edition (Upper Saddle River, NJ: Prentice Hall, 1998).

The intrinsic preference parameters are set to starting values that best represent the modeller's sense of the relative attractiveness to consumers of ICE, hydrogen, and electric vehicles. When hydrogen vehicles are first introduced, there will not be a fully developed infrastructure in place to support them. Correspondingly, the starting intrinsic preference for hydrogen vehicles is less than 50% of that for petrol vehicles. Electric vehicles will fare somewhat better for people can recharge an electric car in their own garage. However, electric vehicles will still be at a disadvantage for longer trips until commercial recharge stations become widespread. Thus, the starting intrinsic preference for electric vehicles is set at less than 60% of that for petrol vehicles. The starting intrinsic preference for electric vehicles is set to calibrate the results to the current composition of the vehicle fleet.

The intrinsic preference parameters for hydrogen and electric vehicles then increase over time as the percentage of HFCVs and EVs increases. The increase over time is modelled as linear until the HFCV, HICEV or EV fleet reaches 15%, at which point consumers are assumed to judge the fleet that reaches 15% with petrol vehicles on the basis of price alone (the intrinsic preference parameter is the same for HFCVs or EVs as it is for petrol vehicles).

Once the share of ICE, hydrogen, and electric vehicles in each of the light imported used, light new, and heavy fleets is determined, the hydrogen and electric vehicle fleets are further subdivided into North and South Island fleets based on the population percentage of each island.

Light new vehicles in New Zealand have an average life of 12 years, and heavy vehicles have an average life of 13 years.[80] Imported used vehicles are on average seven years old at the time of importation, and thus have an average life of five years on New Zealand roads.[81] For any given model year, once the lifespan of the fleet expires, the fleet is assumed to be completely scrapped.

16.3 **Health Costs**

A reduction in health costs accrues in converting the vehicle fleet from petrol/diesel powered to electric and/or hydrogen powered due to the reduction in medical treatment for the effects of NOx, VOCs, CO, ozone and particulates. CO_2 emissions to 2050 from UNISYD2.3 modelling for a fleet consisting of ICEs only is shown in Figure 6.

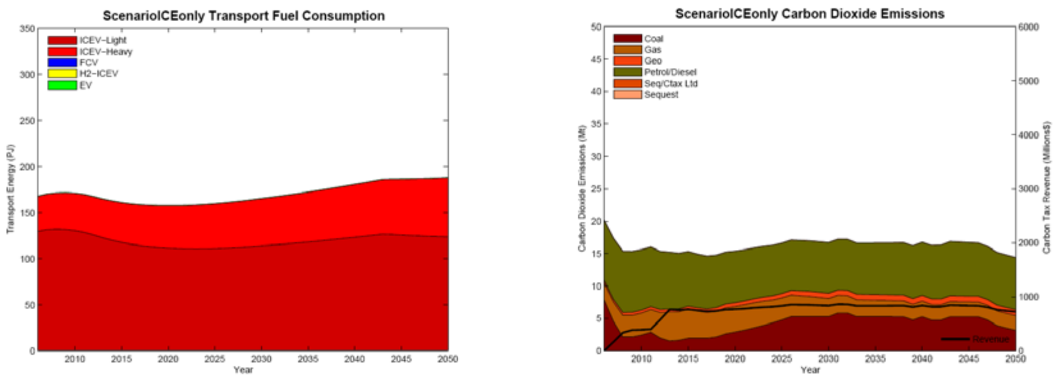

Figure 6: Transport fuel consumption and CO_2 emissions for an ICE only fleet.

[80] New Zealand Motor Vehicle Registration Statistics 2005.
[81] Iain McGlinchy, Ministry of Transport Cabinet Paper (2005).

From the figure above transport related CO_2 emissions to 2050 are about 10 Mt-CO_2 with the light vehicle fleet contributing about 2/3 of the total. CO_2 emissions in 2050 total about 15 Mt.

A graph of the CO_2 emissions for a vehicle fleet consisting of 15% ICEs, 42% HFCVs and 43% EVs in the light vehicle fleet and 100% HFCVs in the heavy vehicle fleet at 2050 is shown in Figure 7.

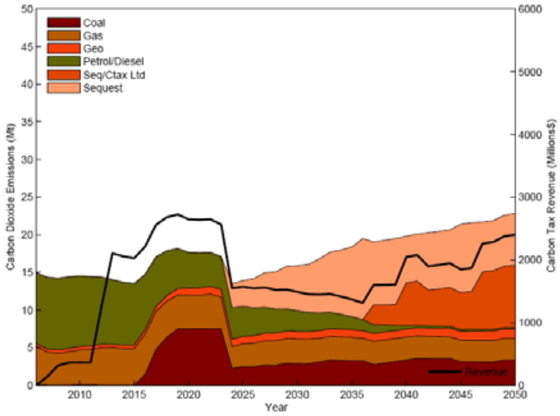

Figure 7: CO_2 emissions for a vehicle fleet with less than 15% Light ICEs.

In this scenario CO_2 emissions total about 16 Mt in 2050 of which about 8 Mt is captured during generation but is emitted either due to sequestration constraints or a preference to pay the carbon tax. While the overall difference in CO_2 emissions between the two different fleet profiles is less than 1 Mt, in the latter scenario, CO_2 transport emissions reduce to only 0.15 Mt.

The costs of air pollution from the 2001 ICE vehicle fleet have been estimated[82] at $442 million. As a result of proposed new emission standards in the USA and Europe the levels of particulates and NOx from new vehicles can be expected to be reduced by at least a factor of 10 over those produced in either the USA or Europe in 1993 as shown in Figure 8.

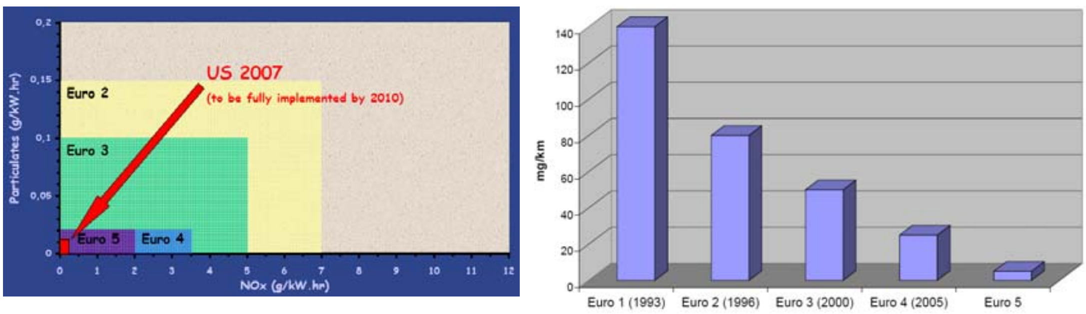

Figure 8: Improvement in particulate and NOx emissions for Europe since 1993[83].

[82] Booz Allen Hamilton, Institute for Transport Studies, University of Leeds, Ministry of Transport "Surface Transport Costs and Charges", March 2005 – Table B12.1.
[83] Schulte-Braucks, R., "European Vehicle Emissions Regulations", Automotive Industry Unit, Enterprise and Industry Directorate-General, European Commission, April 2006.

Given that the average life of light vehicles is 12 years for new light vehicles and 21 years for heavy vehicles it could be expected that the New Zealand vehicle fleet will at least meet Euro 5 standards by 2030 reducing the health costs from $110/person to about $11/person.

If ICE vehicles are phased out then the additional electricity and hydrogen generating plants required to power the EVs and/or HFCVs are likely to be in locations that have minimal impact on the local population due to the constraints of the Resource Management Act 1991. In a study of the effects of bringing 29 proposed new fossil fuel fired plants on line in Virginia, USA[84] it was found that the mortality rate would increase by 0.45 per million over the affected population of 37,900,026 across 19 states. Although the size of the plants was not stated a minimum size of 250 MWe could reasonably be assumed. Even without more detailed information it is apparent that the mortality rate associated with additional centralised power stations in New Zealand will likely be less than 1 premature death per year due to the low narrow north-south aligned shape of New Zealand combined with strong winds that average about 7.5 m/s at 50 metres height associated with latitudes greater than 30 degrees south[85]. On this basis health costs associated with future centralised generation are neglected.

Using the aforementioned philosophy for a population of 5.5 million in 2050[86] the potential health savings in 2050 from phasing out ICE vehicles is therefore equal to 5.5 million people times $11/person or about $61 million as shown in Figure 9.

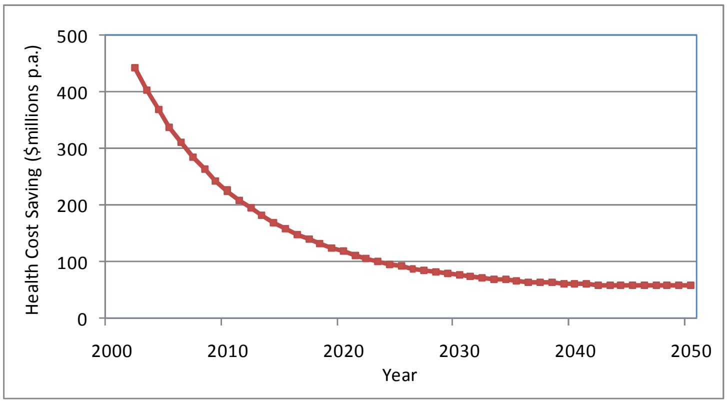

Figure 9: Savings in health costs due to reduced air pollution from phasing in of a zero emission vehicle fleet.

16.4 **Water Pollution Costs**

Water pollution costs in New Zealand for 2001 are estimated at 0.07c/km[82]. A literature survey undertaken by the Victoria Transport Policy Institute[87], gives pollution cost estimates in 1996 $US in the range 0.1 c/mile to 2.6 c/mile with a mean of 1.3 c/mile.

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[84] Hermann, R.P.; Lanier, J.O.; "Predicting premature mortality from new power plant development in Virginia", Environmental Health, 2004

[85] http://www.ocean.udel.edu/windpower/ResourceMap/index-world.html: Accessed 27 Feb 08.

[86] Statistics NZ, "National Population Projections: 2006 (base) – 2061" http://www.stats.govt.nz/products-and-services/hot-off-the-press/national-population-projections/national-population-projections-2006-base-hotp.htm

[87] Victoria Transport Policy Institute, "Transportation Costs and Benefit Analysis", p. 5.15-7, 2007, www.vtpi.org.

This figure is used in the model after updating to 2005 dollars. Hence the assumed value for modelling purposes is 0.97 c/km. The water pollution cost for electric vehicles is half that of petrol/diesel vehicles[87] at 0.52 c/km. No exchange rate adjustment is made in the currency conversion on the basis that pollution costs are proportional to the exchange rate.

16.5 Future Work

The modelling of the consumer vehicle purchase decision making process follows a commonly used modelling technique. In this technique there are two assumptions that deserve close consideration. Firstly, more research can be done to better understand consumer preferences for different vehicle technology types to better parameterise the intrinsic preference parameter. Secondly, it is assumed that imported used light vehicles make up roughly 66% of the entire light vehicle fleet (the sum of all vehicle technologies) throughout the time frame of the model. As the average cost of owning and operating an imported used vehicle versus a new vehicles changes over time, this percentage would likely change—a feedback that should be incorporated in future versions of the model.

An obvious extension of the model would be to include other competing vehicle technologies, such as advanced light diesel vehicles, biodiesel vehicles, hybrid petrol vehicles, and plug-in-hybrid petrol/electric vehicles. In this study effort is focussed on the most likely vehicle alternatives to hydrogen, but further analysis of these other vehicle technology options may be useful.

The model also does not explicitly include the effect of availability of hydrogen fuelling stations on purchasing decisions—this is done only through the intrinsic preference parameter. Researching similar interaction surrounding the introduction of LPG or CNG vehicles during the 1980's may be useful for better understanding consumer behaviour in the introduction of new vehicle technologies.

17 Vehicle Cost Comparison

The *Vehicle Cost Comparison* sector is where the annual costs of owning and operating a HFCV, EV, and ICE vehicle are calculated. Separate annual costs are calculated for each of the fleets described in Table 28.

17.1 Vehicle Costs

The most significant cost included is the vehicle's capital depreciation in its first year which is equal to 15% of the capital cost (i.e., the vehicle purchase price). This depreciation rate is used to annualize the capital cost. For simplicity in the absence of better data, heavy vehicles are considered to have a capital cost twice that of light vehicles for all vehicle fleets. Imported used vehicles are seven years older and have an average price $19,916[80].

The next most significant cost is the fuel cost per kilometre, a function of both fuel economy of the vehicle in question and price of fuel for that vehicle's type. Each fleet has its own per kilometre fuel cost including all taxes except for the Goods and Services Tax (GST), which is added to the capital cost. Next, operating costs are added, which were taken from the NZ Automobile Association.[88] HFCVs and EVs share operating costs from tyres with ICE vehicles, but have lower other maintenance costs due to the

[88] Jim McCutcheon, Car Running Cheaper (New Zealand Automobile Association Inc, 2003).

much reduced number of moving parts. HICEVs are presumed to have the same operating and maintenance costs as ICEVs. Finally, expected registration, warranty of fitness, and insurance costs are added. It is assumed that the Ministry of Transport and insurance companies would treat HFCVs, HICEVs and EVs the same as ICE vehicles.

17.2 **ICEV and HICEV Capital Cost**

Petrol vehicle capital costs are calculated from Statistics New Zealand's Retail Trade Survey and Land Transport NZ registration statistics. In the year 2005, NZ$8.3 billion was reported in motor vehicle retail sales.[89] In the same year, Land Transport reported 230,313 car registrations and 37,080 truck registrations.[90] Assuming trucks (heavy vehicles) have an average cost twice that of passenger vehicles, this works out to an average capital cost per new light vehicle of NZ$27,267. Heavy vehicles are assumed to be entirely run on diesel. This capital cost estimate is correspondingly adjusted for imported used light vehicles as discussed above. Both new and imported HICEVs are presumed to have a capital cost that is 5% higher that ICEVs principally to take account of the additional cost of the fuel storage tank.

17.3 **HFCV Capital Cost**

For HFCVs, the capital cost is determined based primarily on the fuel cell stack cost. To ascertain the price of an entire fuel cell vehicle from the fuel cell stack cost, we use the drivetrain costs for a comparably-powered ICE vehicle for reference. Specifically, the engine plus transmission cost constitutes about 26.5% of a conventional vehicle's manufacturing cost, which in turn represents about 50% of the final retail price.[91] This implies that the drivetrain makes up 13.25% of the retail price of an ICE vehicle. The cost of the HFCV is determined by subtracting the drivetrain component of an ICE and adding the cost of the fuel cell based drivetrain.

The fuel cell stack cost itself is the most significant and possibly the most uncertain driver of the H_2 economy. Model users can choose between two options to determine the cost per kW of the fuel cells stack. Both options rely on assumed decreases in costs over time as research continues into fuel cells. The first option is to simply use a learning curve predicted by Tsuchiya and Kobayashi.[92] The second option allows the model user to easily create a custom learning curve based on their beliefs about how the fuel cell technology will evolve. The variables *Minimum FC Stack Cost per kW (MinStackCost)*, *Years until Global FC Production Doubles (DoublingTime)*, and *FC Learning Percent (LearnPerc)* can together be used to define a learning curve based on the equation

$$FCCost = \max\left(8000 \cdot (1 - .01 \cdot LearnPerc)^{2^{\frac{TIME-2002}{2 \cdot DoublingTime}}}, MinStackCost\right)$$

where *FCCost* is the fuel cell stack cost per kW.

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[89] Retail Trade Survey, December 2005 Quarter, 2005, Statistics New Zealand, Available: http://www.stats.govt.nz/store/2006/03/retail-trade-survey-dec05qtr-hotp.htm?page=para029Master.
[90] New Zealand Motor Vehicle Registration Statistics 2005, Table 28.
[91] R.M. Cuenca, L.L. Gaines and A.D.Vyas, Evaluation of Electric Vehicle Production and Operating Costs (Center for Transportation Research Argonne National Laboratory).
[92] Tsuchiya, Haruki, and Osamu Kobayashi. Mass production cost of PEM fuel cell by learning curve, International Journal of Hydrogen Energy 29 (2004) 985 – 990.

The fuel cell stack cost from the learning curve is per kW, and thus is multiplied by the number of kW needed for a HFCV to be comparable to an ICE vehicle (i.e., 2/3 of 110 kW or 73 kW) to give the total fuel cell stack cost. The balance of plant associated with the stack is assumed to be equal to that of the stack cost.

17.4 **EV Capital Cost**

The EV capital cost is determined similarly to the HFCV capital cost, with the cost of the ICE based drivetrain replaced by the cost of the battery based drivetrain. For EVs, the cost of the drivetrain consists of two components, the battery cost and the motor cost. Estimates of these costs are extrapolated from those by NREL[93] to give our best estimate of a mass produced all-electric vehicle fleet. Extrapolation yields a battery module cost of US$236.6 per kWh and battery energy of 70 kWh, which implies an initial battery pack cost of NZ$25,214. The modeller has full reign to choose how this battery pack cost decreases by 2050 as the technology improves, The US Advanced Battery Consortium target of US$150/kWh[94] is assumed to be achieved in 2030 under a maximum baseline cost decrease of 36%. From NREL[93] the motor cost is estimated at NZ$2,800 for a 73 kW motor and is assumed to remain constant over time, consistent with modelling the cost of petrol vehicles as constant over time.

17.5 **Future Work**

Further research into the relevant costs of each of the vehicle technologies would be useful. This may require interviews with engineers in the industry, for much of the information about the latest technology and how the technology is expected to develop is often considered proprietary.

Assuming light vehicles use only petrol and heavy vehicles only diesel is a model simplification to make cost comparisons easier but does not perfectly reflect reality. It is possible that more of the light fleet may switch to from petrol to diesel, especially as diesel vehicles have improved and have become more widespread globally in the past few years. Further work could explicitly model the diesel light fleet, alleviating this concern. Additionally the model could incorporate various types of light and heavy vehicles (e.g., SUVs, small cars, busses, etc).

Further research into ownership trends, and uses of various vehicle types may improve the model by more carefully identifying the operating costs. One problem in attaining this end is the haphazard motor vehicle registry information collected and released by the NZ government. Since HFCVs and EVs are not currently on the market, the best that can be done for these vehicle technologies is to use the vehicle ownership and use estimates for petrol vehicles. Survey data on the expected purchasers and their planned uses of HFCVs and EVs may be helpful in better assessing these ownership and use trends.

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[93] Markel, A. Brooker, J. Gonder, M. O'Keefe, A. Simpson and M. Thorton, Plug-in Hybrid Vehicle Analysis, National Renewable Energy Laboratory, NREL/MP-540-40609, November 2006

[94] National Research Council (NRC). Review of the Research Program of the FreedomCAR andFuel Partnership. Washington, D.C., 2005. 0-309-09730-4.

18 ICE and HICE Vehicle Market

There is a separate Vehicle Market sector for each of the four vehicle technology types. Each of these contains estimates of fuel economy, annual distance travelled, and total fuel demand. The ICE and HICE Vehicle markets differ from each other two only in the capital cost and modelling of fuel prices.

18.1 Capital Cost of HICE Vehicles

Based on an analysis of cost data for on-board hydrogen fuel tanks[95] HICE vehicles are assumed to cost US$446 more than ICE vehicles due to the additional costs associated with the hydrogen fuel tank.

18.2 Fuel Economy and Distance Profile

One key simplifying assumption made in the fuel economy calculation is that all vehicles in each petrol fleet start with the average fuel economy of the fleet. Each fleet's fuel economy can then be modelled dynamically or defined statically via the *Mandate Fuel Economy* variable. The fuel economy for used light vehicles is set to the fuel economy from seven year prior (the average age of imported used vehicles at the time of importation).

When modelled dynamically, the price of petrol (or diesel) drives changes in fuel economy. The initial fuel economy values for light and heavy ICE and HICE vehicles are the low bound values given in Table 29 and Table 30 respectively. As the price of petrol rises, purchasers of ICE and HICE vehicles demand better fuel economy. We use a fuel price-elasticity of demand for fuel economy of 0.6,[96] i.e., a 10% increase in fuel costs leads to a 6% increase in fuel economy). Vehicles in the fleet maintain their fuel economy throughout their lifetime so that changes in average fleet fuel economy occur in the order of 10-15 years.

Table 29: ICE Vehicle Fuel Economy

		ICEV Type		
		Imported Light	New Light	Heavy
Fuel Economy	Low Bound	8.73[97] km/L	12.47[98] km/L	3.6[99] km/L
	High Bound	19.267[100] km/L	19.267[101] km/L	5.55 km/L

[95] International Energy Agency "Prospects for Hydrogen and Fuel Cells" (2005) Table 3.7.
[96] James L Sweeney, "Personal Communication," ed. Andrew Baglino (2003),
[97] Author's calculations based on the estimate for New Light vehicles and New Zealand Energy Outlook to 2030.
[98] Paul Kruger, John Blakeley and Jonathan Leaver, "Energy Resources for Developing Large-Scale Hydrogen Fuel Production in New Zealand," 14th Annual Meeting, National Hydrogen Association (Washington, DC: 2003), vol., Table 1, p.3.
[99] Kruger, Blakeley and Leaver, "Energy Resources for Developing Large-Scale Hydrogen Fuel Production in New Zealand," vol., Table 1, p.3.
[100] Gm Well-to-Wheel Analysis of Energy Use and Greenhouse Gas Emissions of Advance Fuel/Vehicle Systems - a European Study (Ottobrunn, Germany: L-B-Systemtechnik Gmbh, 2002), p.81.
[101] Gm Well-to-Wheel Analysis of Energy Use and Greenhouse Gas Emissions of Advance Fuel/Vehicle Systems - a European Study, p.81.

When the fuel economy is mandated, it follows a linear path from the low bounds to the high bounds as shown in Table 29 and Table 30 over the time period modelled. The same fuel economy is applied to both new and used vehicles.

The starting values for the number of kilometres per year that ICE and HICE vehicle owners drive as a function of the fuel price are 14,598 km per year for imported used light vehicles and new light vehicles, and 28,237 km per year for heavy vehicles. We use a fuel price elasticity of -0.2,[102] (i.e., for a 10% increase in the price of fuel, vehicle owners drive 2% less).

Table 30: HICE Vehicle Fuel Economy

		HICEV Type		
		Imported Light	New Light	Heavy
Fuel Economy	Low Bound	33.0 km/kg	47.20 km/kg	13.62 km/kg
	High Bound	72.93 km/kg	72.93 km/kg	21.01 km/kg

18.3 **Petrol Price**

We assume that all heavy ICEs are fuelled by diesel and pay the road user charge (RUC) for 6 tonne trucks, while all light vehicles are fuelled by regular petrol. This plays a significant role in defining the price interactions and outcomes of the *Vehicle Cost Comparison* sector. The model does not include GST or retailer markup in fuel prices, but includes the fuel taxation estimates given in Table 31.

Table 31: Fuel Taxation as of 2006

Tax(¢/l)	Description
Petrol[103]	
18.708	Excise Tax
23.2	National Roads Fund
6.465	Others
Diesel[104]	
.025	Petrol Fuels Monitoring Levy
.33	Local Authority Tax
RUC	4.662 c/km[105]

Petrol prices are based on the *International Oil Price*. The reference value of this parameter is US$55/bbl, but this value can be changed easily in the control panel. This price can be roughly correlated with the pre-tax prices as follows:

[102] Terry Dinan and David Austin, Reducing Gasoline Consumption: Three Policy Options (Congressional Budget Office, The Congress of the United States, 2002), p. 17.
[103] Energy Data File, Table I.11a.
[104] Energy Data File, Table I.11b.
[105] Road User Charges, (Wellington, NZ: Land Transport Safety Authority, 2007) p.18.

91 octane petrol price (NZ c/l) = US$/bbl x 1.27
Diesel price (NZ c/l) = US$/bbl x 1.54.

The modeller can also modify the path of petrol prices over time through the *Petrol Price % Increase* parameter, which represents the amount the modeller expects petroleum to rise or fall (linearly) by 2020. Similarly, the variable *Petrol Tax Increase* controls a one-time increase in taxation over 2008 levels.

19 HFCV Market

The *HFCV Market* is very similar to the *ICE Vehicle Market.* Also, the price of hydrogen is determined in the *Hydrogen Generation* sector and thus is not included here. However, the fuel economy, distance travelled, and total hydrogen demand are calculated in this sector.

19.1 Fuel Economy and Distance Profile

The fuel economy specified in the *HFCV Market* is in kilometres per kilogram (a kg of hydrogen has the same energy content as 3.8 litres of standard petrol). Each fleet's fuel economy can again be modelled dynamically or defined statically via the *Mandate Fuel Economy* variable.

The starting values for the fuel economy are the low bound values gives given in Table 32. The fuel economy for new vehicles is modelled so it adjusts to the price of hydrogen via the same fuel price elasticity that is used for ICE vehicles. Imported used vehicles are again modelled to have the same fuel economy as new vehicles seven years prior and their initial fuel economy is set to be the same as new light vehicles for lack of other data.

Table 32: HFCV Fuel Economy

		Vehicle Type		
		Imported Light	New Light	Heavy
Fuel Economy	Low Bound	103.39 km/kg	103.39 km/kg[106]	29.77 km/kg
	High Bound	112 km/kg	112 km/kg[107]	32.24 km/kg

When the fuel economy is mandated, it again follows a linear path from the low bound to the high bound as shown in Table 29 and Table 32 over the time period modelled. For light vehicles, the low bound number represents Ford Motor Company's best guess at an achievable fuel economy, while the high bound represents GM's guess of a theoretical best case fuel economy. Data for the heavy vehicles was extrapolated from petrol vehicle heavy/light ratios and the high/low ratios for light vehicles.

The number of kilometres driven per year for HFCVs is modelled the same as for ICE vehicles, and the starting values are also assumed to be the same.

[106] C. E. Thomas, I. F. Kuhn, B. D. James, F. D. Lomax and G. N. Baum, "Affordable Hydrogen Supply Pathways for Fuel Cell Vehicles," International Journal of Hydrogen Energy 23.6 (1998).
[107] Gm Well-to-Wheel Analysis of Energy Use and Greenhouse Gas Emissions of Advance Fuel/Vehicle Systems - a European Study, p.81.

20 EV Market

The *EV Market* sector is modelled similarly to the HFCV sector. Again, the fuel economy can be modelled dynamically or statically defined by a mandated fuel economy standard. The initial fuel economy values when the fuel economy is modelled dynamically are the low bounds in Table 33. The fuel price elasticities are the same as those used for HFCVs.

EV heavy vehicles incur battery management fee. HEVs have a fuel economy ranging from 1.99 – 3.07 km kWh (Table 33). Heavy vehicles with a 140 kWh battery capacity and range 279 – 430 km average 28524 km/yr. Assuming 250 working days this equates to 114 km per day or the need to recharge about every 3.2 days. A nominal recharge fee of NZ$24 is imposed to cover additional labour and any vehicle downtime over ICE vehicles. The total charge for the year is therefore NZ$1886. Light vehicles are assumed to be recharged without penalty.

If fuel economy standards are mandated, fuel economy is modelled to follow a linear path from the low bounds to the high bounds in Table 33, just as in the HFCV market. These values are the same as the petrol vehicle fuel economy values, only converted to kWh with an efficiency correction[108]. This assumption gives EVs an optimistic upper bound fuel economy as ICEs are likely t o improve engine efficiency at a greater rate than EVs.

Table 33: EV Fuel Economy

		Vehicle Type		
		Imported Light	New Light	Heavy
Fuel Economy	Low Bound	6.90 km/kWh	6.90 km/kWh	1.99 km/kWh
	High Bound	10.66 km/kWh	10.66 km/kWh	3.07 km/kWh

The number of kilometres driven per year for EVs is again modelled the same as for ICE vehicles, and the starting values are also assumed to be the same.

The price of electricity used for electric vehicles comes from the *Electricity Generation and Pricing* sector.

21 Hydrogen Generation

The hydrogen generation sector of the model is where the decisions about when, how, and at what cost hydrogen production will take place. The entire driving force of hydrogen generation is the fuel cell vehicle market. Hydrogen demand for industrial processes, local co-generation, or for use as storage medium in the grid system or with renewable sources is not modelled, but should be considered for future work.

[108] Kromer, M.A., Heywood, J. B. “Electric Powertrains: Opportunities and Challenges in the U.S. Light-Duty Vehicle Fleet”, May 2007,Massachusetts Institute of Technology, Publication No. LFEE 2007-02 RP.

Instead, the entire hydrogen part of the model can be broken down into two main parts—forecourt production methods, where hydrogen is generated and stored on site at the vehicle-filling station, and centralised production involving cryo-tankers to transport liquid hydrogen to stations where it is stored until use[109]. Key indicators for production via each method are shown in Table 34. The hydrogen generation sector coordinates the development of both production types according to the hydrogen demand and prices of individual production techniques. In many ways it resembles the *Electricity Generation and Pricing* sector.

It is important to reiterate that all the hydrogen related sectors operate simultaneously in two different markets—there is a separate one on each Island. Plants built on one Island cannot distribute hydrogen to the other and vice versa. There are separate base prices and demands associated with each market. Every dynamic associated with demand and price occurs in each market independently.

Table 34. Key Indicators of Hydrogen Production Methods

	Central Plants[110]				**Forecourt**	
	Coal[111]	**Biomass[112]**	**LSMR[113]**	**Coal Cogen[114]**	**SSMR[115]**	**Electr-olysis**
Fuel Consumption (MJ/kg H2)	231.45	262.27	206.14	351.33	189.92	0
Thermal HHV efficiency (%)	61.35%	54.14%	68.88%	40.42%	74.60%	0
Electricity (kWh/kg H2)	15.50	16.71	11.20	-24.22	3.07	42[116]
Capital and O&M Cost[117] ($NZ)	$2.77	$3.08	$1.46	$5.19	$3.29	$3.28[118]
CO2 Emissions[119] (kg CO2/kg H2)	20.54	0.00	10.76	1.71[120]	9.93	0

Note: LSMR – large SMR; SSMR – forecourt SMR

Each of the centralised hydrogen production sectors contains identical logic, with only the inputs and price calculations differing between them. In each sector, potential generators are considered to be of any of the following size plants: 75, 100, 200, 400, and 800 tonnes of hydrogen per day. Plants are also broken down into the 13 electrical

[109] For more info on hydrogen pathways, please see Dale R. Simbeck and Elaine Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis (Mountain View, CA: SFA Pacific, Inc., 2002).
[110] Centralised plant data shown is for 400,000 kg H_2 per day plants (Only affects capital cost data).
[111] Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis, p.56.
[112] Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis, p.49.
[113] Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis, p.51.
[114] D. Gray and G. Tomlinson, Hydrogen from Coal (Mitretek, 2002), p.12 APB-6.
[115] Duane B. Myers, Gregory D. Ariff, Brian D. James, John S. Lettow, C. E. (Sandy) Thomas and Reed C. Kuhn, Cost and Performance of Comparison of Stationary Hydrogen Fueling Appliances (Arlington, VA: Directed Technologies, Inc., 2002), p. 3,122.
[116] Expectation of achievable efficiency.
[117] For central plants: Capital charges of 16.2%, O&M is 6% of Capital. Forecourt: Capital charges of 18%, O&M is 3.5% of Capital. See Appendix of Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis.
[118] $2.1 million dollar electrolyser cited in Appendix B: Josephine Howes, "The Potential for Renewable Hydrogen as a Transport Fuel for the Uk," MSc, University of London, 2002.
[119] Only direct emissions are shown. Indirect (i.e. emissions for electricity) are not included.
[120] 26.5 kg CO_2 per kg H_2 is sequestered.

regions where they can be constructed. The specific production pathways included in the analysis are:

- Biomass gasification.
- Coal gasification.
- Coal co-generation of hydrogen and electricity using a solid oxide fuel cell topping cycle and sequestering CO_2.
- Large steam methane reforming.

In total there are 4 centralised plant types each with 5 sizes for 13 regions available to be constructed.

While the production of hydrogen by electrolysis of water is not viable for centralised production, it is viable for forecourt production in regions where no natural gas pipeline infrastructure currently exists.

The modeller can define the uncertain cost of biomass used in hydrogen production with the *Dry Bio Mass $ per GJ* variable. There is the potential for large quantities of biomass for hydrogen production in New Zealand, but a dollar value is not forthcoming.

Delivery from these plants is via liquid hydrogen tankers, considered to be the most economic for New Zealand's demography. Delivery distances of 250 km in the North Island and 400 km in the South Island were included. Specifics surrounding trucking costs and tanker carrying capacity are from Simbeck.[121] Delivery via gaseous tankers and pipelines was not considered viable and therefore not modelled, but could be added to future versions of the model.

For simplicity's sake, the largest (and cheapest, on a unitised basis) fuelling stations, capable of dispensing 2000 kg of H_2 per day, are the only ones used in the central plant infrastructure part of the model.

In every time step, the model does four important things in this sector. It uses the number of vehicles and driving behaviour from *H2 Vehicle Market* sector to determine changes in and the total amount of hydrogen demand. It then looks at existing and ageing forecourt and centralised capacity in each market and ascertains the amount of capacity needed to be built in order to meet that demand. Next, it sorts out how much hydrogen will be produced on-site in each market and then arranges to deliver the remaining quantity via liquid tanker truck from producers in that market. Finally, it determines hydrogen prices in the two markets and for the different vehicle types to best equilibrate supply and demand.

21.1 **Capacity: When and What is Built**

Whenever there is more demand than production capacity, the model must decide what type of capacity to build. If the economics for the construction of centralised plants are not feasible given existing demand in a given market, then the cheapest forecourt plants available are built to fill the need. The only options for forecourt generation are steam methane reforming and electrolysis. However, steam methane reforming is assumed to be unavailable in the South Island, where there is no reticulated gas.

[121] Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis.

To gain an understanding of where centralised hydrogen plants would be built (and how H_2 production would impact regional carbon emissions), the centralised hydrogen sector is regionalised by the same regions as the electricity sector on the supply-side. As electricity prices vary by region in the model, those variations will impact the optimal placement of hydrogen facilities, with their electricity-intensive liquefaction process. Inversely, Plants using coal for cogeneration of electricity and hydrogen are net electricity producers, and they will likely want to cluster themselves in electricity-starved, high priced regions where their electricity co-product is more valuable.

The economics behind central hydrogen plant construction are determined in the *Hydrogen Plant Siting* and *Future Hydrogen Plant Construction* sectors. Every time step in which there is a defined centralised need in a given market, the model tries to find the optimal technology, electric region, and plant size triplet (where optimal is defined as lowest production cost) to build to meet the need.

For a triplet to qualify, the electric region can have no other centralised hydrogen plant currently under construction. Triplets will also only qualify if the technology's production cost in a particular region is less than a three-year futures price of hydrogen (*Capital Planning H_2 Price)* scaled up or down by the tightness or looseness of the current supply market, similar to the scaling in the electricity sector. Triplets involving plant sizes larger than the projected hydrogen need—a forecast of hydrogen demand three years into the future based on a running average of the previous three years—are also disqualified.

The model then builds the optimal qualified triplet. After a predetermined amount of construction time, that amount of hydrogen will become available in the trucked H_2 market on the Island in question.

As industry is risk averse and the hydrogen economy is subject to the "chicken or egg" paradox, it is useful to model the impact of less risk-averse industry. Industry might re-classify the risk of hydrogen investment if government considered incentives or even funding to aid the creation of centralised infrastructure. Via the *Enthusiastic H2 Plant Building* variable, the modeller may simulate this re-classification of risk. The way this occurs is by predicting more hydrogen demand than the model would normally foresee.
The *Enthusiastic H2 Plant Building* variable feeds hydrogen producers inflated predicted demand numbers that make investment seem less risky. In the real world, monetary transfers or purchase guarantees would probably be needed to hedge the risk of centralised hydrogen infrastructure. In a model that doesn't simulate capital flows, this system works just as effectively.

21.2 **Timing of Generation**

The model assumes that filling stations with forecourt generators will use them throughout their effective lifetime. This makes forecourt capacity must-use, or base load capacity, in an analogy to electricity generation. The validity of this assumption is questionable, for in reality, the filling station's decision to use forecourt generation will depend on everything from hydrogen demand and prices for alternative options to filling station debt and accounting styles. All hydrogen need beyond forecourt capacity is trucked to filling stations from central producers.

21.3 **Hydrogen Price**

Hydrogen pre-tax prices in the model depend entirely upon what production options are available for filling stations to choose from. Before there is any hydrogen demand or producers, the model gives *H2 Sell Price $ per kg* as a theoretical price which is based on the minimum of the forecourt options available in each market. This is done because the forecourt production options are always the first constructed, as initial demand is small. As centralised producers build plants, their economy of scale encourages price reductions. In many model runs, centralised production is never economical, and forecourt prices dominate. This is more often the case in the South Island, with lower captive demand than the North Island.

Hydrogen is taxed at exactly the same energy-specific rate as petrol for light vehicles and diesel for heavy vehicles, including a Road User Charge (RUC). These taxes can be changed by the modeller via the *Hydrogen Tax Subsidy* variable in the Control Panel. Hydrogen taxation decisions are arbitrary and speculative. Further research may reveal how exactly a taxation scheme might work. The final prices used in the model do not include GST or retailer mark-up to assure uniformity with the petroleum-pricing scheme employed.

21.4 **Capital Cost**

The variables *H2 Prod Capital Cost Red Target Year* and *H2 Prod Capital Cost Red Factor* represent the learning curve reductions in the capital costs of hydrogen production technology. A simple linear reduction of *H2 Prod Capital Cost Red Factor* occurs by *H2 Prod Capital Cost Red Target Year*. This offers the modeller the ability to see what effects, if any, rapid development and improvement in hydrogen production technology has on the viability of the hydrogen economy.

21.5 **Future Work**

The hydrogen generation logic has been one of the focal points of the work thus far done on the model. Aside from the pricing issues mentioned above, the area in which attention has been lacking includes the regional distribution of hydrogen filling stations needed to meet demand. The competitive nature of filling stations, including their franchise behaviour, will also have an effect. One retailer might be willing to outfit a certain percentage of their stations early on with hydrogen ready technology. Such corporate-specific behaviour has not been included here, but could accelerate hydrogen price reductions.

Unlike electricity, trucked hydrogen will probably be delivered to stations on long-term contracts, and this contractual behaviour should be incorporated. Also, each individual station tends to have different input prices, and thus coming up with a single sell price for each Island may be over-aggregation.

All the data used for the centralised producers was adapted from two publications[122]. More publications on hydrogen production should be referenced, for currently the model is a little source dependent. If either of these publications is in error, then the model is in error. The economic decisions made while adapting the data in these publications should be cross-referenced with common practice by NZ industries and utilities.

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[122] Gray and Tomlinson, Hydrogen from Coal, Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis.

22 Hydrogen Wholesale Market

The *Hydrogen Wholesale Market* sector operates identical to the *Wholesale Price Calculation* sector for electricity, except it breaks hydrogen production into markets for each Island. The *Hydrogen Wholesale Market* sets a trucked hydrogen price in order to equilibrate hydrogen demand and the supply curves of the various centralised hydrogen producers. Supply curves are similar to those described for electricity generators.

23 Forecourt Steam Methane Reforming

The *Small Steam Methane Reforming* (SSMR) sector is essential to initial development of hydrogen infrastructure, especially in model runs where *Ignore LNG* is not selected by the modeller. It is a forecourt hydrogen production pathway and doesn't incur upfront costs of large capital plants or trucking/pipeline infrastructure; therefore, it (or electrolysis, the other forecourt pathway) is the production method used to fuel the first HFCV cars. As the hydrogen market matures, if hydrogen is needed, and centralised generation cannot provide for all of it, then SSMRs or electrolysers will be built to fill the gap. In the South Island, where there is no access to reticulated natural gas, SSMR is never an option: electrolysis must and will be built to meet hydrogen demand.
The sector can be broken into three parts; the economics logic, the construction logic, and the input demand logic. The SSMRs modelled here are factory-produced, can support about 1600 vehicles (equivalent to a large petrol station)[123].

23.1 Economics

SSMRs have two inputs, natural gas and electricity. The electricity price used is the average price from the various electricity regions on the Island in question. The prices of both inputs directly affect the price of hydrogen produced. The carbon tax on natural gas fuel also plays a role in the SSMR economics, and for the purposes of this model, SSMRs were assumed to emit the same amount of CO_2 per PJ of gas as gas-fired power stations.

23.2 Construction and Capacity

When deciding to construct SSMRs, the model takes a number of steps. (These steps are identical to those taken in the *Electrolysis* sector.) First, the model determines how many units are needed to meet the capacity needed. Where there is reticulated natural gas, if SSMR is a cheaper forecourt option than *Electrolysis*, and if no centralised plants are under construction, then the forecourt SSMR is built. Fifteen years later, it is decommissioned. Once a SSMR reformer is built, its capacity is at the whim of availability of natural gas, and in gas-constrained model runs, the sector is prone to sudden losses in production capacity due to natural gas shortages especially when imported LNG is not available.

23.3 Future Work

The small steam methane reforming sector relies heavily on a single body of information[124]. Monitoring of developments in reforming technologies and projections for the availability and cost of mass-produced small reformers will ensure inputs remain realistic.

[123] Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis.
[124] Simbeck and Chang, Hydrogen Supply: Cost Estimate for Hydrogen Pathways - Scoping Analysis.

24 Electrolysis

The *Electrolysis* sector closely mirrors the other forecourt sector, *Small Steam Methane Reforming*, just discussed. Similarly, the electrolysis units involved can support approximately 1600 vehicles and are assumed to be mass-produced. The only major difference is the electrolysis units do not rely on natural gas and therefore can be deployed anywhere in NZ. Thus they are integral to the development of hydrogen production infrastructure in the South Island. A further assumption that the efficiency of electrolysis units will improve from 66% to 78% by 2020 is included. Monitoring of developments in factory-assembled small-scale electrolysers is necessary to maintain accurate information in this sector. The electricity price used is the average price from the various electricity regions on the Island in question.

25 Carbon

25.1 **Carbon Taxes**

Carbon taxes are modelled in two phases in the model. The first phase begins in April 2007 and lasts throughout the first Kyoto commitment period. The second phase begins in 2013 and continues throughout the modelling duration. The charge is applied to every ton of emitted (not sequestered) CO_2, at a rate determined by the *Carbon Tax 2008 $ per T CO2* and *Carbon Tax 2013 $ per T CO2* variables.

25.2 **Sequestration Availability and Costs**

The IPCC has determined that costs of carbon capture and sequestration range from US$14 – 91 with transportation, geological storage and monitoring costs ranging from US$1.6 – 16.3[125]. Sequestration into oil and gas fields in New Zealand has been assessed by assuming that reservoirs have an average depth of 2500 m, have a hydrostatic pressure profile, a geothermal temperature gradient of 30 C/km and are composed of methane. The density of CO_2 and CH_4 are shown in Figure 10.

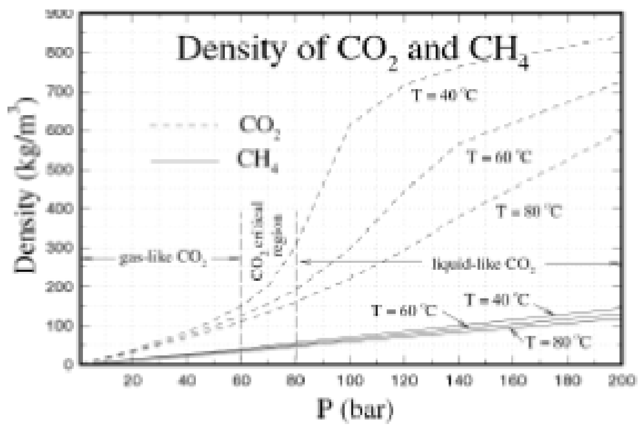


Figure 10: Variation in density with pressure CO_2 and CH_4[126]

From Tables H1 and H2 of the July 2005 EDF, the ultimate recoverable reserves for gas are shown at STP conditions of 60 F (15.6 C) and 1 atm (~101 kPa). The volume factor,

[125] Carbon Dioxide Capture and Storage, eds. Bert Metz and Ogunlade Davidson (IPCC, 2005) Table TS.9.
[126] C.M. Oldenburg and S.M. Benson, "Carbon Sequestration with Enhanced Gas Recovery: Identifying Candidate Sites for Pilot Study," First National Conference on Carbon Sequestration (NETL, 2001), vol.

B; the ratio of the reservoir volume to the volume at STP, for CO2 and CH4, are 0.0026 and 0.0046 respectively.

The ultimate reservoir volume of gas at STP is 157.4 Gm^3. This equates to 0.72 Gm^3 at reservoir conditions. From Tables H1 and H2 oil volumes are 2% of the total oil and gas volume and are therefore ignored. The mass of CO_2 that can be sequestered is therefore 526 Mt.

Ultimate recoverable reserves do not incorporate enhanced gas recovery to extract all the methane. Consider the reservoir depleted at a pressure of 50 bars[127]. The density of CO_2 at this pressure is 100 kg/m^3. Thus, an additional 73 Mt of CO2 can be sequestered. Hence the total CO_2 that can be sequestered in deleted oil and gas fields is estimated at 599 Mt.

However, CO_2 can also be sequestered in deep saline aquifers. In the absence of specific New Zealand data, based on Table 35 the total capacity of deep saline aquifers in New Zealand is assumed to be equal to that of the gas fields, and located proportional to region area as shown in Table 36.

Table 35: Estimate of Storage Capacities for Different Geological Trap Types[128]

Storage Option	**Global Capacity**	
	Gt-CO_2	**% of total emissions to 2050**
Depleted gas fields	690	34
Depleted oil fields/CO_2 EOR	120	6
Deep saline aquifers	400-10,000	20-500
Unminable coal seams	40	2

Table 36: Regional Sequestration Capacity

Region	**Area (km^2)**	**Seq Capacity- Cmax (Mt)**
Northland (S-W)	13941	30
Auckland	5600	12
Bay of Plenty	12447	27
Waikato	25598	56
Taranaki	7273	16+599=615
Central	22215	48
Hawkes Bay	22515	49
Wellington	8124	18
Nelson/Marlborough	22715	49
Canterbury	30231	66
South Canterbury	15115	33
Otago/Southland	66337	144
West Coast	23336	51
Total	275447	1198

[127] Oldenburg and Benson, "Carbon Sequestration with Enhanced Gas Recovery: Identifying Candidate Sites for Pilot Study," vol.
[128] John Gale, "Overview of Co2 Emission Sources, Potential, Transport and Geographical Distribution of Storage Possibilities," IPCC Workshop on CO_2 Capture and Storage (Regina, Canada: 2002), vol.

The post-capture sequestration supply curve for each region is assumed to span the full range of US$1.6 – 16.3 per t-$CO_2$. Thus each region's sequestration supply curve is expressed simply as Price (\$US/t-CO_2) = $(C/C_{max})(14.7) + 1.6$ where C is the cumulative sequestration to date in the region and C_{max} is the total sequestration possible in the region.

Part II: Computer Model Control Panel

26 Model Control Panel Variables

The following variables help to define the characteristics of electricity demand and production throughout the time period modelled.

26.1 Primary Variables

The primary model control panel is shown in Figure 11. These are the variables that have the most influence on the model outputs due to a combination of their uncertainty and significance.

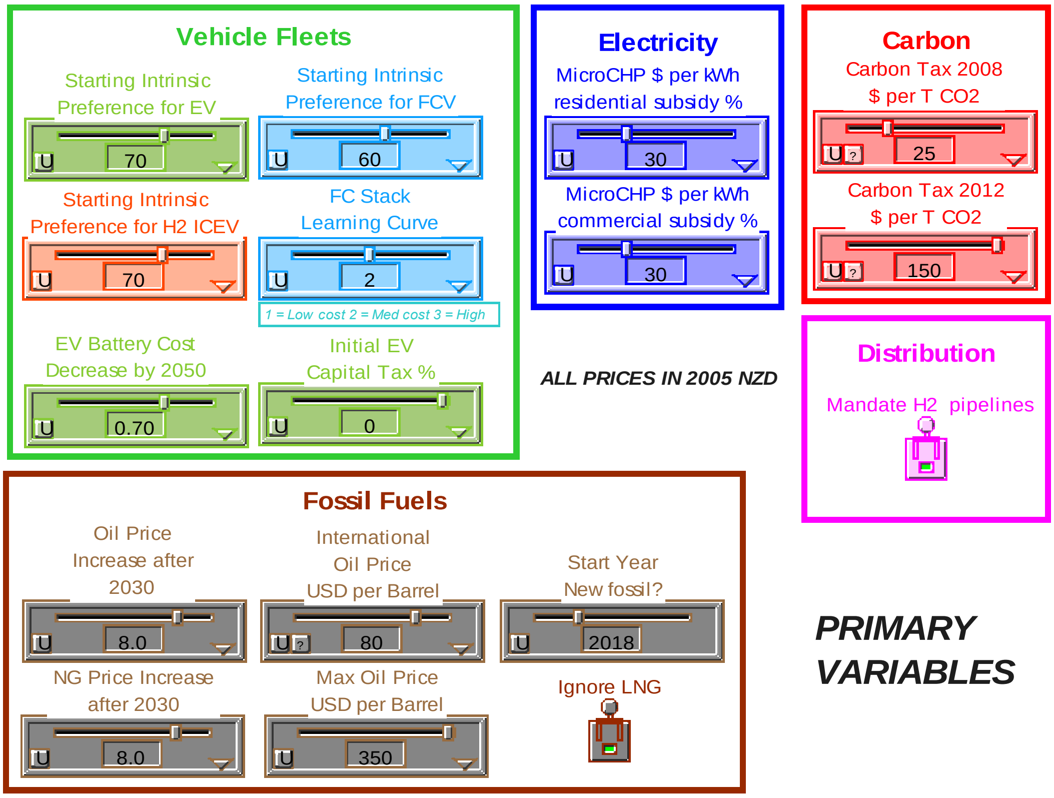


Figure 11: Sample Model Control Panel for Primary Variables

26.1.1 Oil and Gas Price

Oil and natural gas increase in price at the same rate. The profile of price increases was assessed as either 4% or 8% per annum from a base oil price of US$100/bbl in 2008 with the maximum price increase being 150%.

26.1.2 Imported Liquefied Natural Gas

The economics of the natural gas sector are critical to the modelling results, as the fuel is a feedstock for both electricity and hydrogen production. The availability of imports also determines viability of new investment in large-scale natural gas usage in the electricity and hydrogen generation sectors, as current projected resource availability does not allow for much increase in gas usage. Gas is presumed to be imported from Australia.

The option to consider imported LNG being available is controlled by the toggle *Ignore LNG.* The year at which LNG importation begins is contained in the secondary variables.

26.1.3 Vehicle Fleet Starting Preference

The consumer choice of vehicle fleet is determined by the logit algorithm that weighs both economics and consumer resistance to the adoption of new technology. The authors assessed the base case values for the *Starting Intrinsic Preference* which forms part of the logit algorithm as 70 for HICEVs and EVs, and 60 for HFCVs. A value of 100 implies that consumers are equally at ease with the technology as they would be with conventional ICEV technology. Values above the base case values are considered a positive consumer bias towards the technology while values less than the base case are considered a negative consumer bias.

26.1.4 Electric Vehicle Technology

The battery pack is one of the most expensive components of electric vehicles and thus, is an important determinant of whether or not EVs become economical. The EV battery cost is assumed to linearly decrease in cost, reaching a value by 2050 controlled by the slider *EV Battery Cost Decrease by 2050*. This parameter tells the percentage decrease in battery cost by 2050 (e.g., 0.7 is 70%).

26.1.5 Carbon

The cost of carbon emission and sequestration is very influential on modelling results. It affects the cost of electricity, hydrogen, and the fuel costs for petrol vehicles. The following variables determine these costs.

Carbon taxes are modelled in two phases in the model. The first phase begins in April 2007 and lasts throughout the first Kyoto commitment period. The second phase begins in 2013 and continues throughout the modelling duration. The charge is applied to everything that emits CO_2, at a rate determined by the *Carbon Tax 2008 $ per T CO2* and *Carbon Tax 2013 $ per T CO2* variables.

Hydrogen and electricity plants designed to capture CO_2 must pay a cost to transport and sequester their captured emissions. The cost is modelled as:-

$$(\$US/t\text{-}CO_2) = (C/C_{max})(14.7) + \textit{Carbon Sequestration Base Cost}$$

with a maximum of *Maximum Carbon Sequestration Cost*, where C, and C_{max} are regional quantities.

26.1.6 Micro-generation $ per kWh subsidy

Some scenarios include micro-scale combined heat and power (CHP) generation using either hydrogen or natural gas as feedstock taking a 20% share of the residential and commercial electricity markets. Subsidies of up to 30% are implemented for micro-generation as at this level of subsidy natural gas fed residential micro-generation becomes viable in most scenarios for periods of about 20 years.

26.2 **Secondary Variables**

The model control panel for secondary variables is shown in Figure 12. These are the variables that have important influence on the model outputs but have either greater certainty and/or are changed less frequently than the primary variables.

SECONDARY VARIABLES

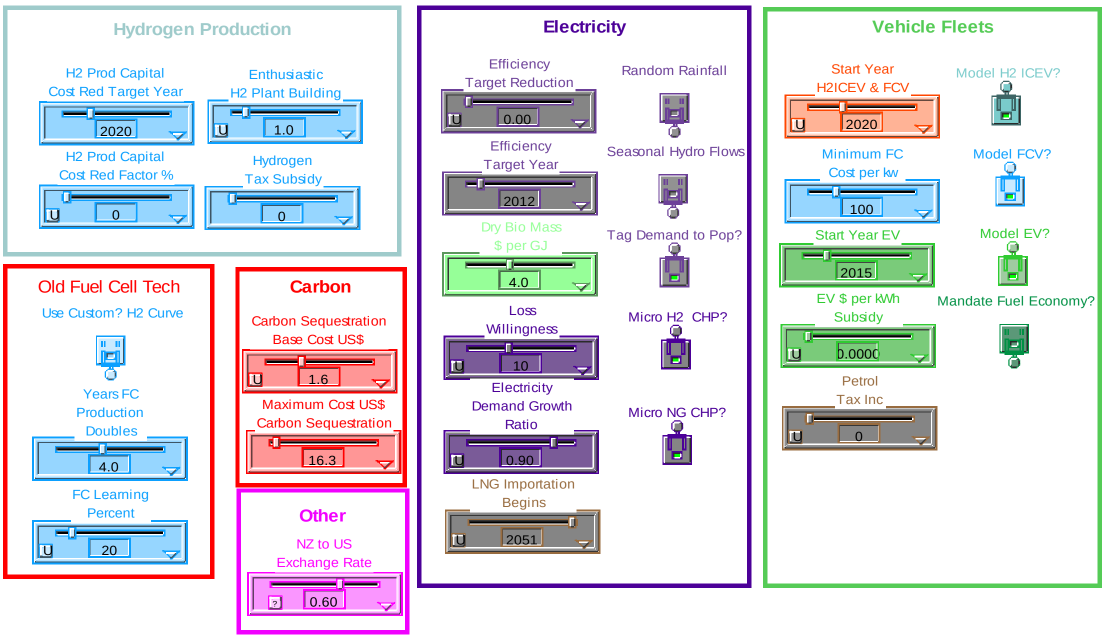


Figure 12: Sample Model Control Panel for Secondary Variables.

26.2.1 Fuel Cell Technology

The custom learning curve described in the *Vehicle Cost Comparison* sector is completely defined by the fuel cell technology parameters on the control panel. The assumed decrease in fuel cell stack costs is quite possibly the most important determinant of whether HFCVs become widely adopted.

26.2.2 Electricity

This sector has the key parameters that govern how the electricity system works.

The static electricity demand definition used for the residential, industrial, and commercial sectors can be toggled with the *Tag Demand to Pop?* switch in the model control panel. When this switch is on, the model increases electricity demand in constant ratio to population growth. When this switch is off, the model maintains exponential growth, in ratio to growth in GDP. The exact ratio is defined by the *Electricity Demand Growth Ratio* variable.

The second set of two parameters enables the modeller to set an energy efficiency target to work towards through government incentives and programmes. The *Efficiency*

Target Reduction and *Efficiency Target Year* variables allow the modeller to see the effects of attaining such targets, by linearly reducing overall demand until the target reduction percentage is achieved in the target year.

The next parameter, *Loss Willingness*, is very important in determining the extent to which generation plants will continue to operate if the price of electricity is below the generation cost in any one time period. To examine this we model electricity *and* hydrogen generator's supply curves as follows (notation is based on model variable names):

$$quantitysupplied = lesserof\begin{pmatrix} \left(\dfrac{offerprice}{costofgeneration}\right)^{losswillingness} \\ or \\ 1.0 \\ \end{pmatrix} * capacity$$

Thus, for offer prices over the cost of generation for the generator, generators produce at full capacity. For prices less than the cost of generation, they produce exponentially less according to the *Loss Willingness*, which represents the generators tendency to sell below profitability to retain market share, or avoid mothballing plants.

The *Random Rainfall* variable can be used to switch between simulated seasonal changes in rainfall for an average year. The simulated seasonal changes pick from a normal distribution of rainfall four times a year, using smoothing algorithms to accomplish even transitions. This variable directly impacts the amount of hydro-electricity produced.

The switches, *Micro H2 CHP?* and *Micro NG CHP?,* can be used to control whether micro-generation technology is introduced into the model.

Finally, if the modeller does not wish to model growth of distributed solar power, the *Ignore Solar* variable can be switched on in the model control panel.

26.2.3 Vehicle Market

The vehicle fleet sector in the control panel gives the option to toggle off HICEVs (*Model H2 ICEV?*), HFCVs (*Model FCV?*) and EVs (*Model EV?*), so that we can examine a reference case of only petrol vehicles. It has a similar toggle for mandated fuel economy standards (*Mandate Fuel Economy?*). When fuel economy is mandated, it follows a linear path from pre-determined high and low bounds over the time period modelled.

The parameters *Start Year EV* and *Start Year H2ICEV and FCV* can be used to set the year of introduction of these vehicle fleets into New Zealand.

A separate parameter controls the tax or subsidy on each vehicle technology type: HFCVs, EVs, and ICE vehicles. In the reference case, hydrogen is taxed at exactly the same energy-specific rate as petrol for light vehicles and diesel for heavy vehicles, including a Road User Charge (RUC). These taxes can be changed via the *Hydrogen Tax Subsidy* variable in the control panel. Similarly, an additional subsidy can be placed on the price of electricity used for electric vehicles, through the variable *EV $ per kWh*

Subsidy. We assume that the electricity used to fuel an EV can be differentiated from residential household use of electricity (possibly by an inexpensive meter), so the subsidy is only placed on electricity used by EVs. To create a disincentive for petrol vehicles, the modeller can also add to the petrol tax by using the variable *Petrol Tax Increase*, which implements a one-time increase in taxation over 2008 levels.

26.2.4 Hydrogen Production

It is important to stress that most of the hydrogen production technologies incorporated in the model are still experimental technologies. In the control panel, the modeller can use the variables *H2 Prod Capital Cost Red Target Year* and *H2 Prod Capital Cost Red Factor* to control capital cost reductions due to improvements in these technologies. A simple linear reduction of *H2 Prod Capital Cost Red Factor* occurs by *H2 Prod Capital Cost Red Target Year*. This offers the modeller the ability to see what effects, if any, rapid development and improvement in H_2 production technology has on the viability of H_2 economy.

Because industry is risk averse and the hydrogen economy is subject to the “chicken or egg” paradox, it is useful to model the impact of less risk-averse industry. Industry might re-classify the risk of hydrogen investment if government considered incentives or even funding to aid the creation of centralised infrastructure. Via the *Enthusiastic Plant Building* variable, the modeller may simulate this re-classification of risk.

The modeller can also define the uncertain cost of biomass used in hydrogen production with the *Dry Bio Mass $ per GJ* variable.

26.2.5 Imported Liquefied Natural Gas

The variable *LNG Importation Begins* in the control panel control determines the timing of LNG imports.

26.2.6 Carbon

Hydrogen and electricity plants designed to capture CO_2 must pay a cost to transport and sequester their captured emissions. The cost is modelled as

$$(\$US/t\text{-}CO_2) = (C/C_{max})(14.7) + \textit{Carbon Sequestration Base Cost}$$

with a maximum of *Maximum Carbon Sequestration Cost*, where C, and C_{max} are regional quantities.

Part III: Results

27 Scenario Description

Key characteristics of each scenario are outlined in the Table 37 with the overall assumptions detailed in Table 38. Graphical outputs for each of the 7 scenarios are included for:

- Electricity generation, regional and national
- Electricity price, regional and national
- Hydrogen production, regional and national
- Hydrogen price, national
- Carbon emissions and sequestration, regional and national
- Gas and coal use.
- Numbers of light vehicles (ICE, HFCV, HICE, and EV).
- Numbers of heavy vehicles (ICE, HFCV, HICE, and EV).
- Transport fuel consumption
- Water and Air Pollution Costs

*Table 37: Scenario-Specific Assumptions**

	Laissez-faire			Interventionist				
Scenario	LF	LF w/o LNG	LF with H_2ICEVs	High CO_2 tax	High petrol & NG price	No H_2 production	Subsidised central production	High elect. growth
Abbreviation	LFwLNG	LFNoLNG	GoAll	HighCTax	HighOilNG	NoH2	CP	HighElec
CO_2 Tax (NZ$/t)								
2008-2012	25	25	25	25	25	25	25	25
2013-2050	50	50	50	100	50	50	50	50
Electricity Growth above Population	1% pop = 1.16% residential 1.5% commercial 1.39% industrial demand							N/A
Electricity/GDP growth ratio	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.9
LNG Imports from:	2018	Never	2018	2018	2018	2018	2018	2018
NG and oil price increase (%/a) after 2008.	4	4	4	4	8	4	4	4
Hyd. Production	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes

Table 38: Overall Assumptions for ICEV HFCV EV Fleets

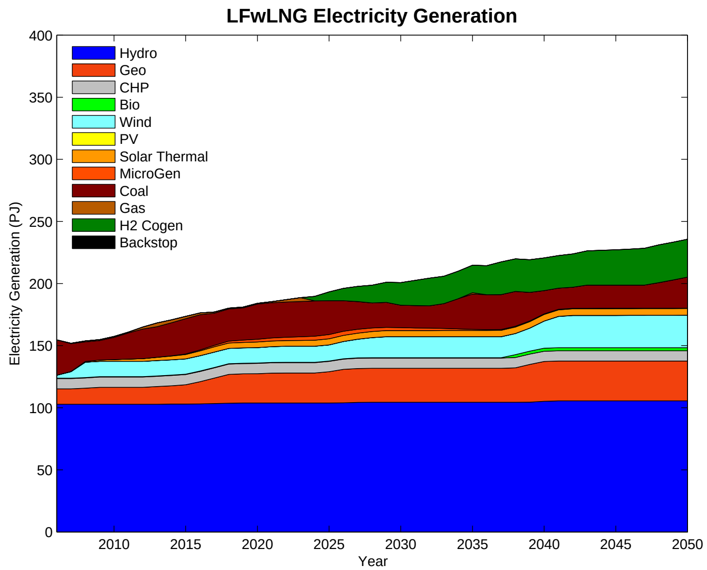
Item	Value		Comment	
Untaxed Petrol price (c/L)	US$/bbl x 1.27		Untaxed at port	
Untaxed Diesel price (c/L)	US$/bbl x 1.54		Untaxed at port	
Dry biomass	$4.0/GJ		Delivered	
Domestic Gas	$7.75/GJ		Wellhead	
Imported LNG	[2.003 + 0.0493 × (International Oil Price – 1)+1.25]/Exchange rate			
International Base Oil Price	US$100/bbl		Maximum oil price is US$250/bbl	
GDP Growth	2.5% p.a.			
NZ to US Exchange Rate	0.60			
Light Vehicle Fleet				
Growth	2.07% p.a.			
Maximum ownership	0.6 per capita			
	ICE	*H2ICE*	*HFCV*	*EV*
Initial Fuel Economy	12.5 km/litre	47.3 km/kg	103 km/kg	6.9 km/kWh
Initial Use	14,598 km p.a.			
Heavy Vehicle Fleet				
Growth	2.03% p.a.			
Maximum ownership	0.15 per capita		0.15 per capita	
	ICE	*H2ICE*	*HFCV*	*EV*
Initial Fuel Economy	3.60 km/litre	13.6	29.8 km/kg	1.99 km/kWh
Initial Use	28,237 km p.a.			
Hydrogen Sector				
Minimum FC stack cost per kW Including balance of plant	US$30/kW			

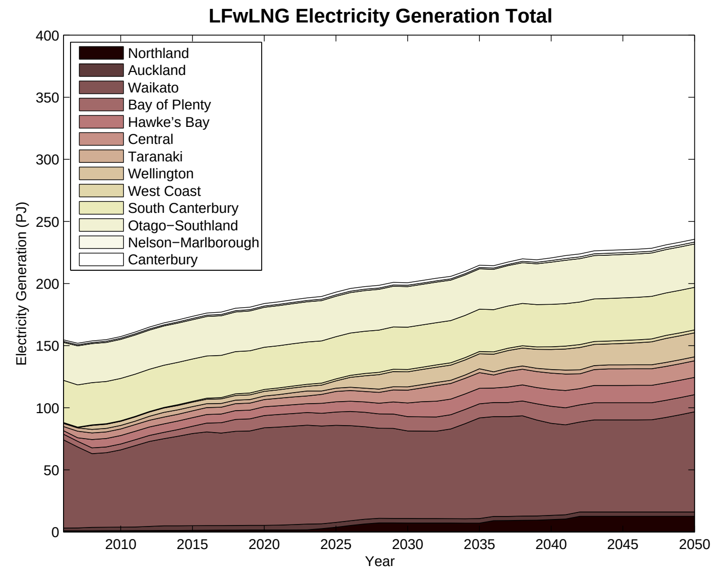
28 Scenario: Laissez-faire

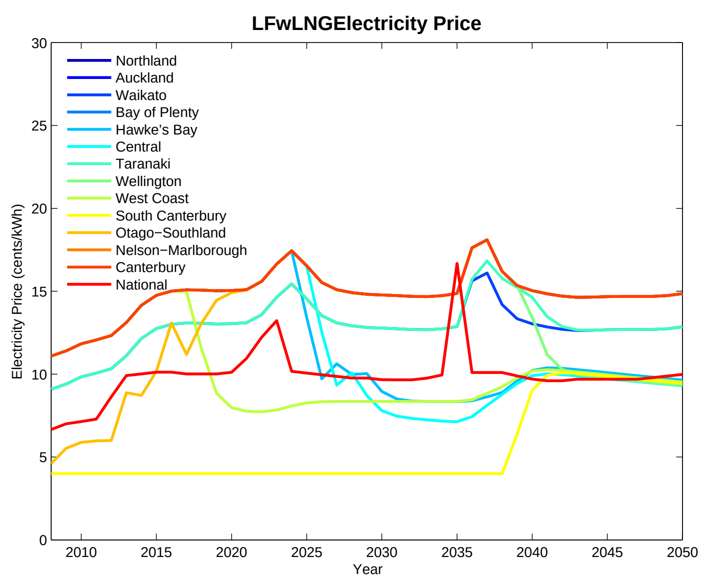
Key results for this scenario are:

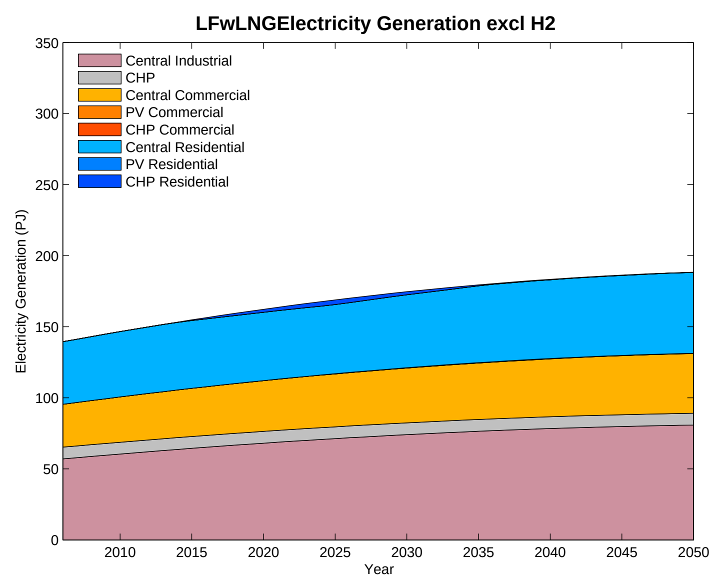
- National wholesale electricity price rises to 9.9 c/kWh in 2013 due the impact of the carbon tax. After 2020 it averages 10.3 c/kWh to 2050.
- CO_2 emissions in 2050 are 13% below 2006 levels with 17% of total emissions being sequestered. A further 35% of emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 81% in 2025 and 76% in 2050.
- Hydrogen generation in 2050 consists of 9% electrolysis, 11% forecourt SMR, 32% biomass gasification, and 48% coal cogeneration.
- Primary fossil fuel energy use increases by 46% between 2006 and 2050.
- 64% of the light vehicle fleet switches to HFCVs by 2050 with 22% switching to EVs. HFCVs begin to enter the market in significant numbers after 2020 when growth is rapid due to the reducing capital cost of fuel cells and increasing oil price.
- The heavy vehicle fleet is entirely HFCVs by 2033.
- Air and water pollution costs reduce from $722 million in 2006 to $153 million in 2050.

The National Electricity Market

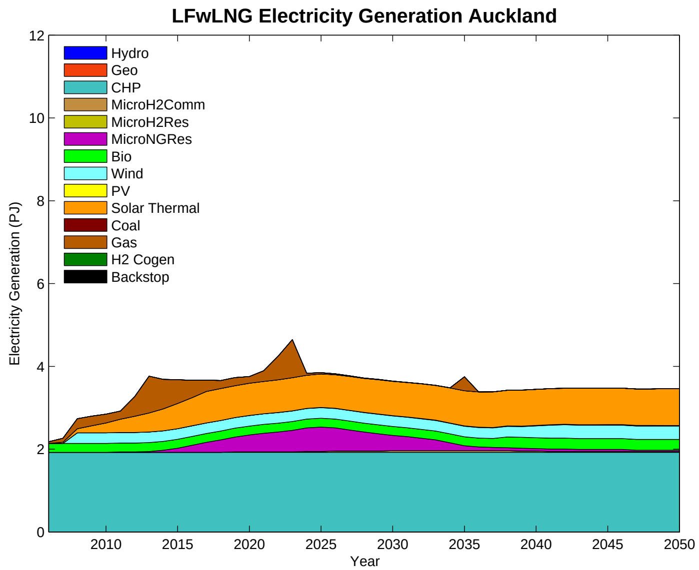


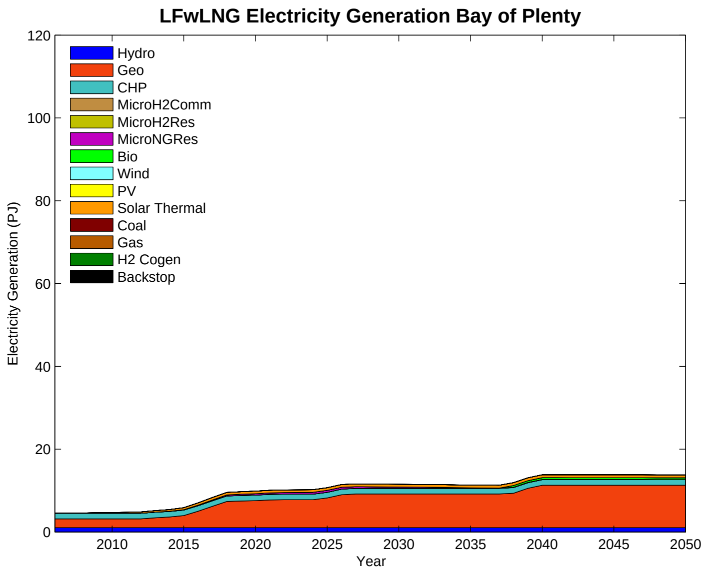


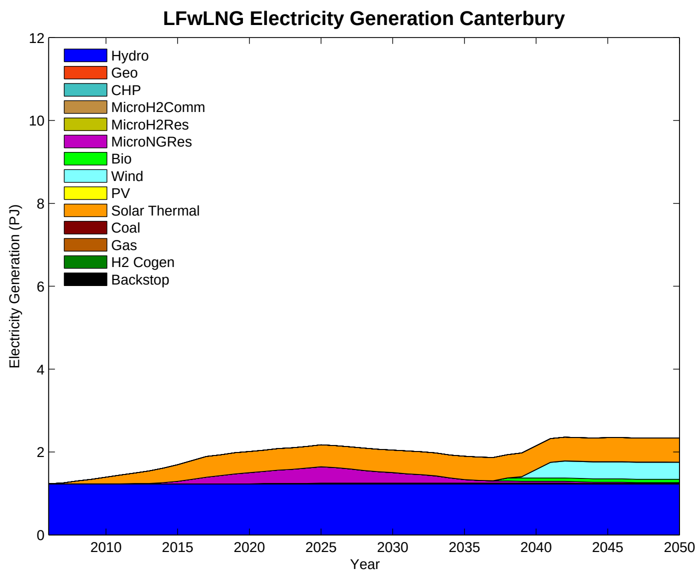


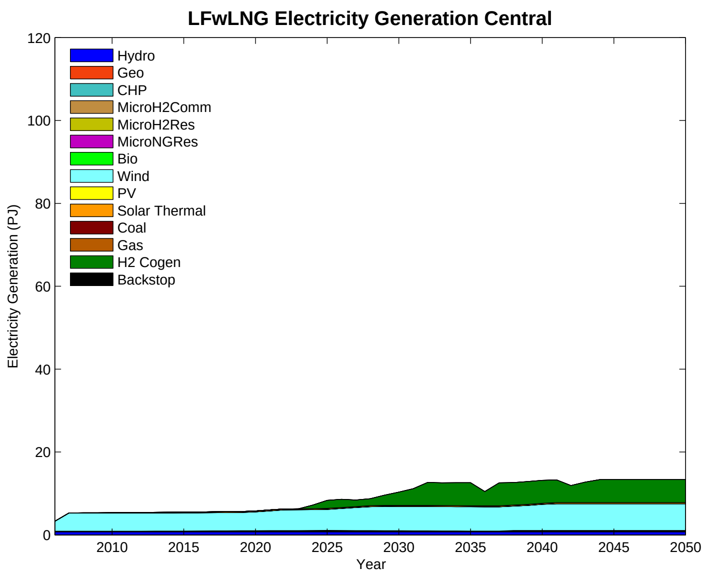


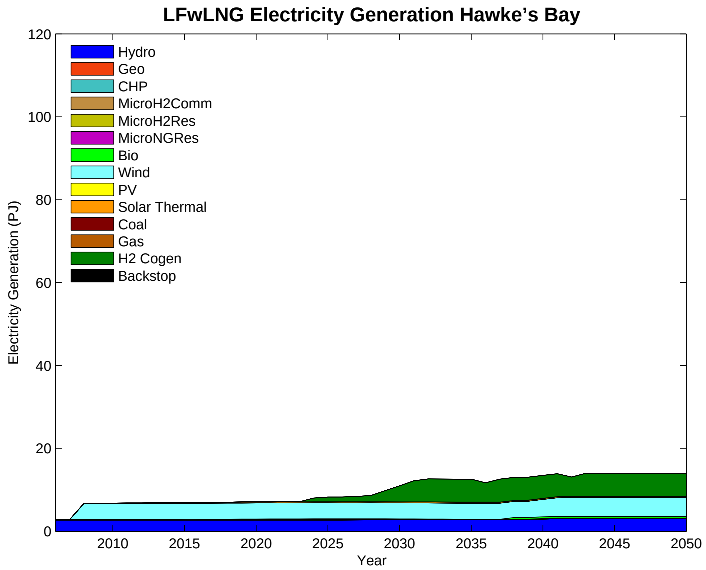
Regional Electricity Markets

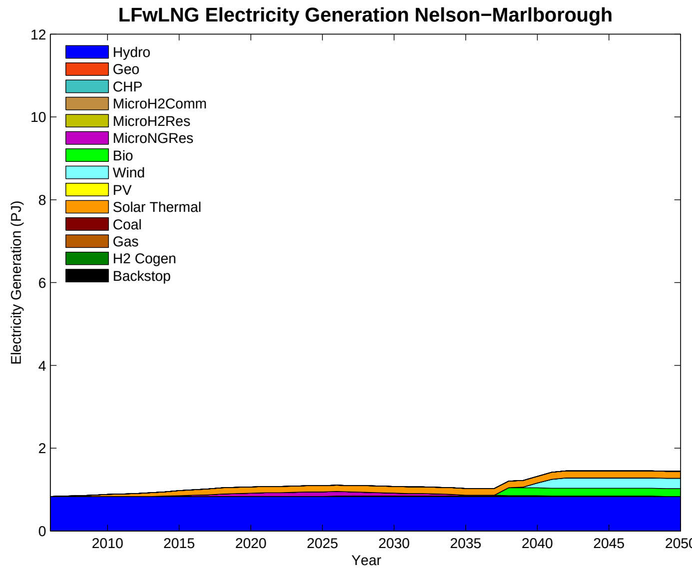


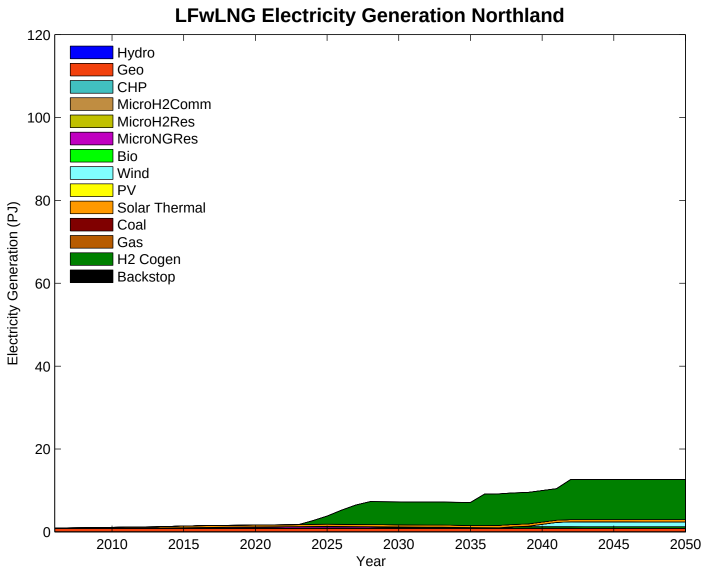


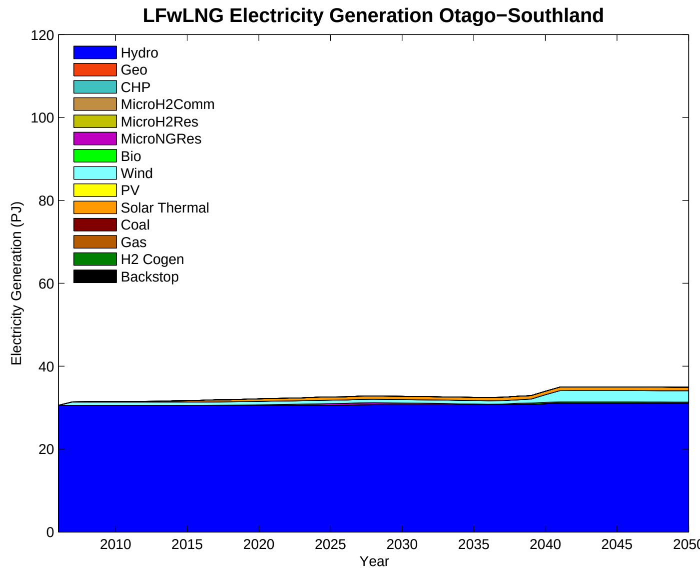


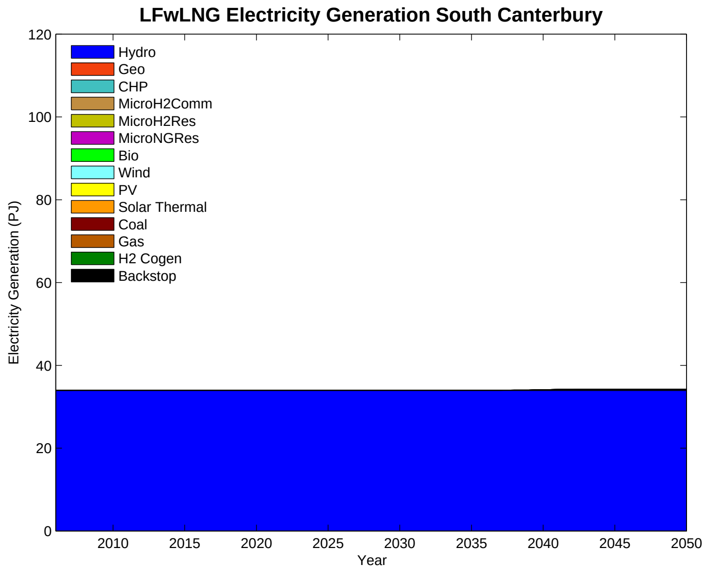


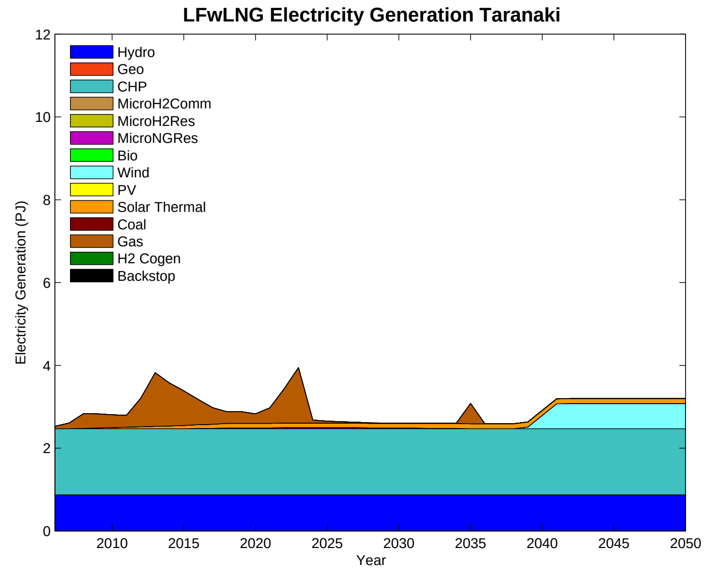

LFwLNG Electricity Generation Hawke's Bay
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

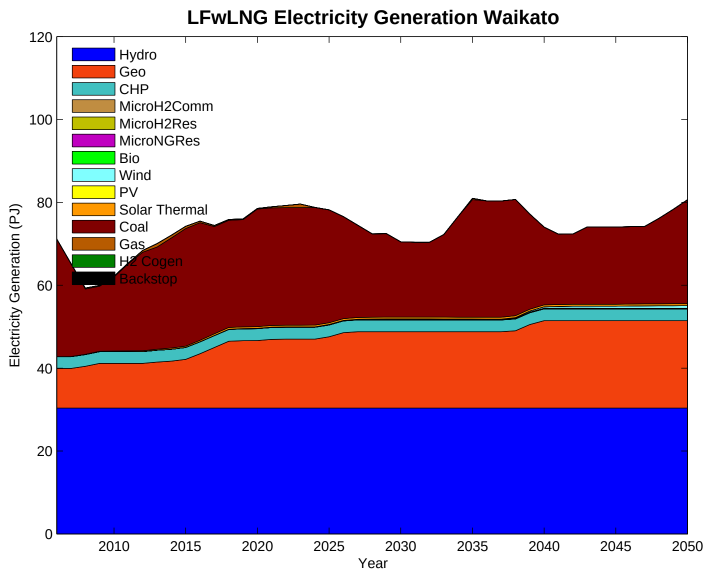

LFwLNG Electricity Generation Nelson−Marlborough
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

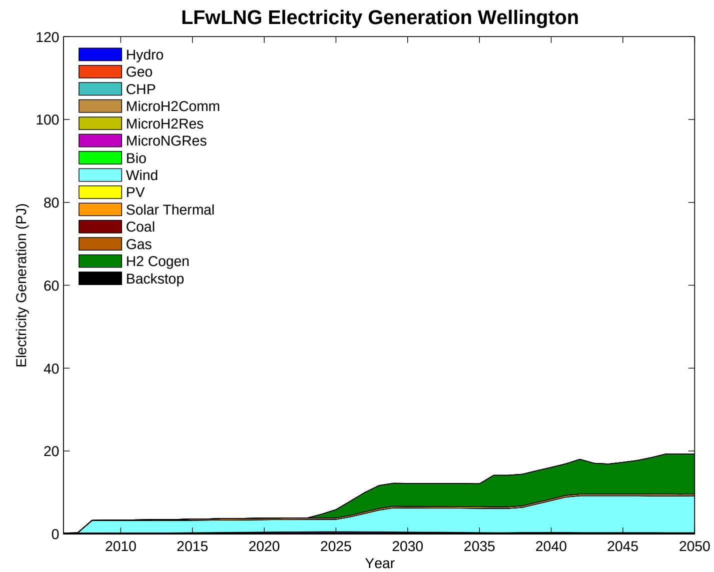

LFwLNG Electricity Generation Northland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

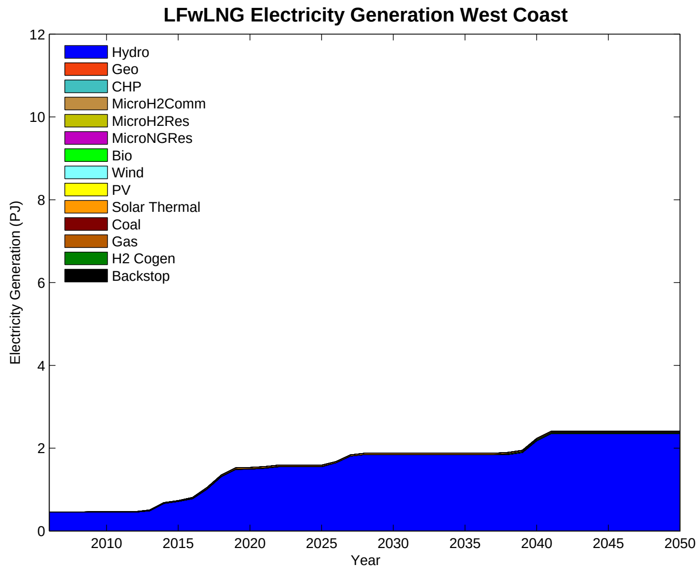

LFwLNG Electricity Generation Otago−Southland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


LFwLNG Electricity Generation South Canterbury
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

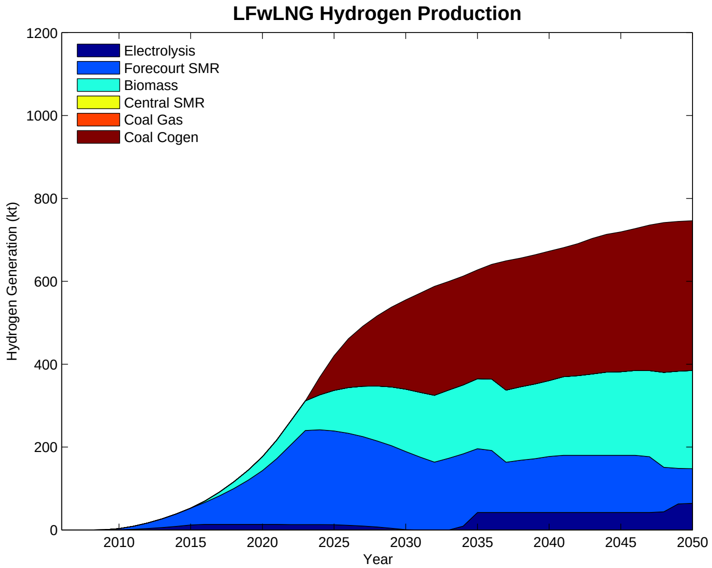

LFwLNG Electricity Generation Taranaki
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

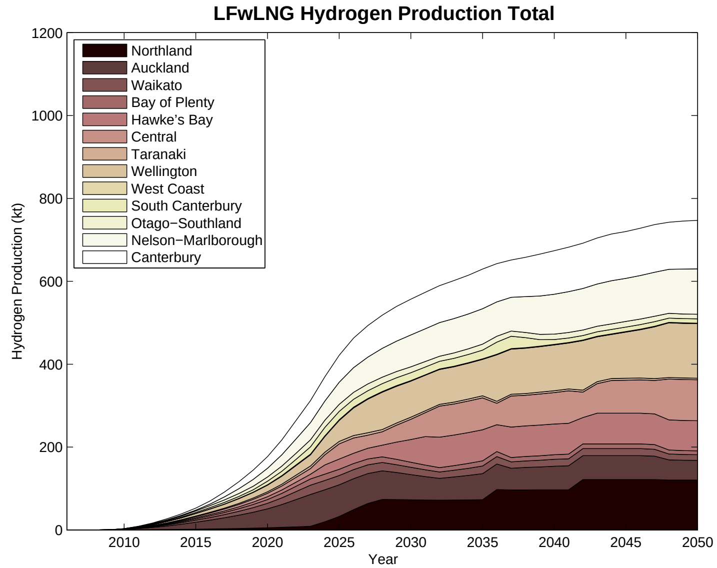

LFwLNG Electricity Generation Waikato
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

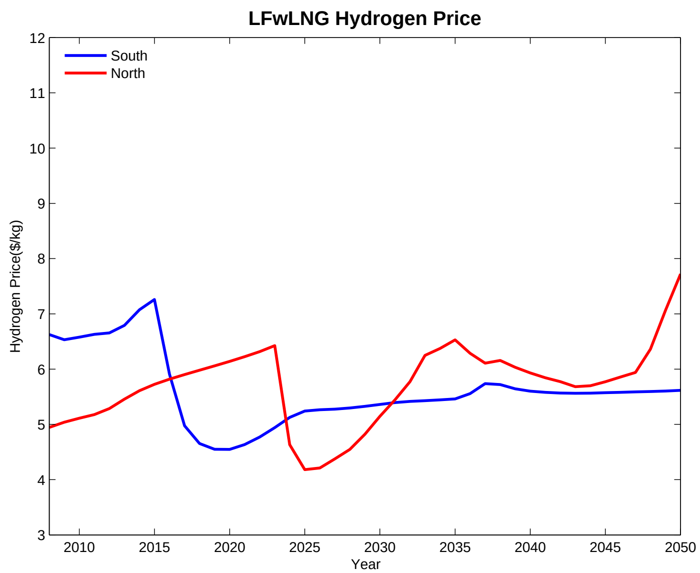

LFwLNG Electricity Generation Wellington
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


LFwLNG Electricity Generation West Coast
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050

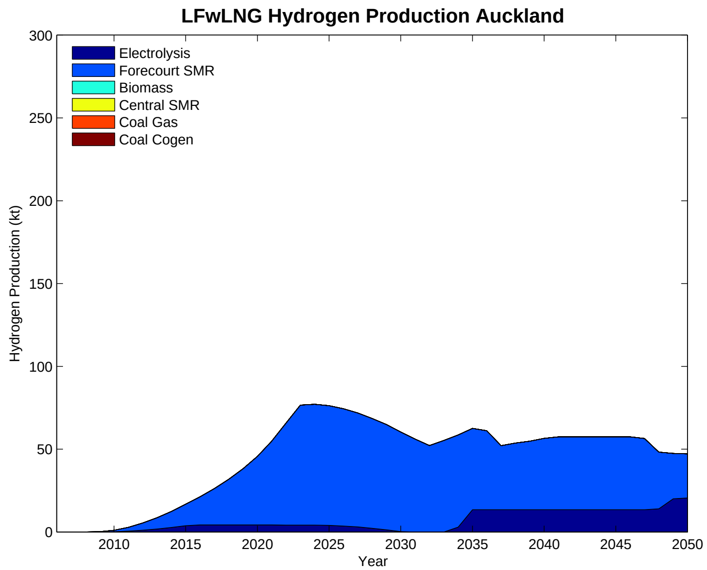
The National Hydrogen Market

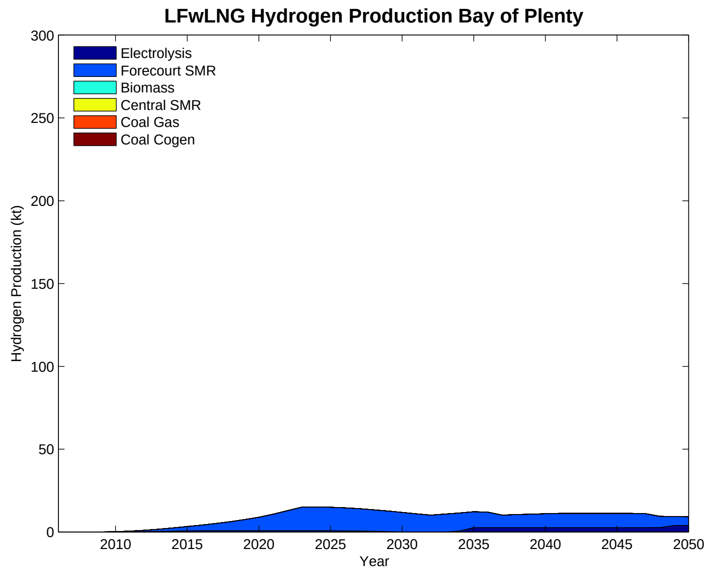


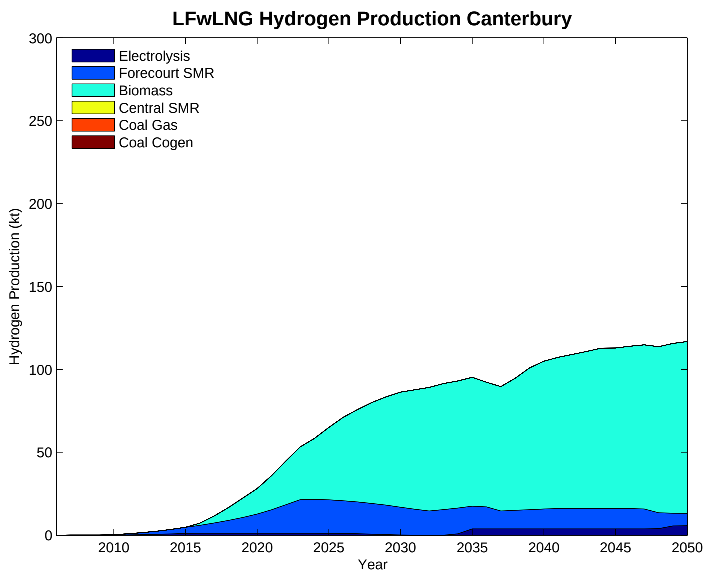


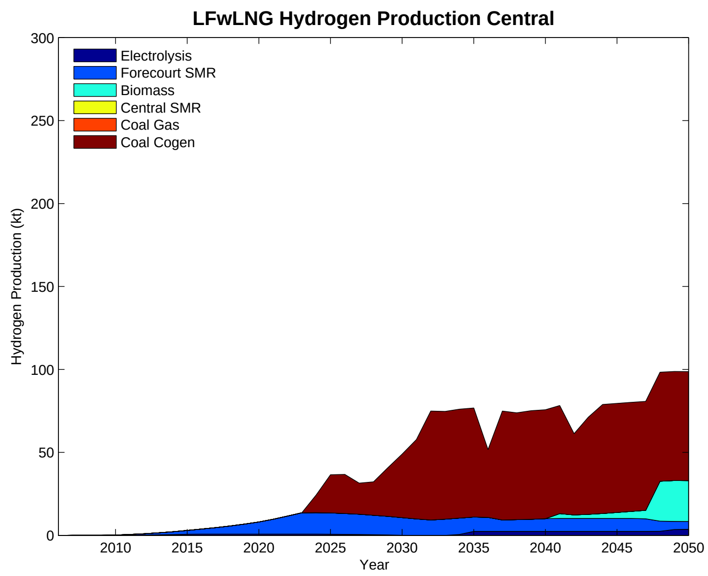


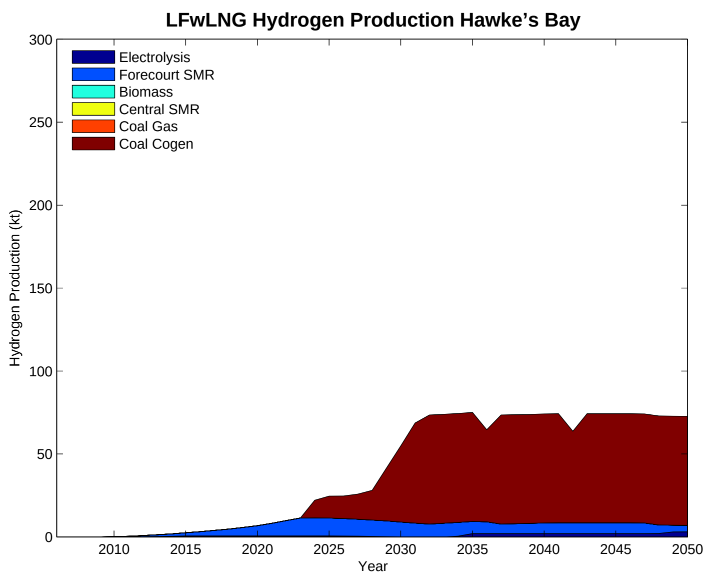
Regional Hydrogen Markets

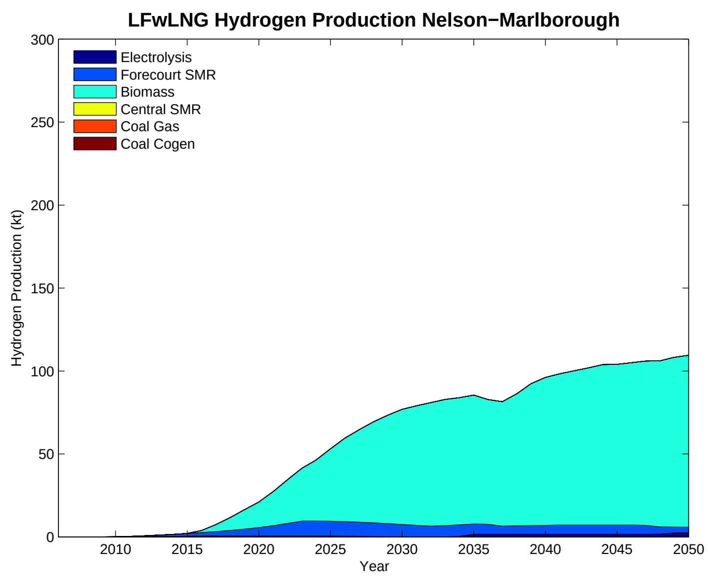


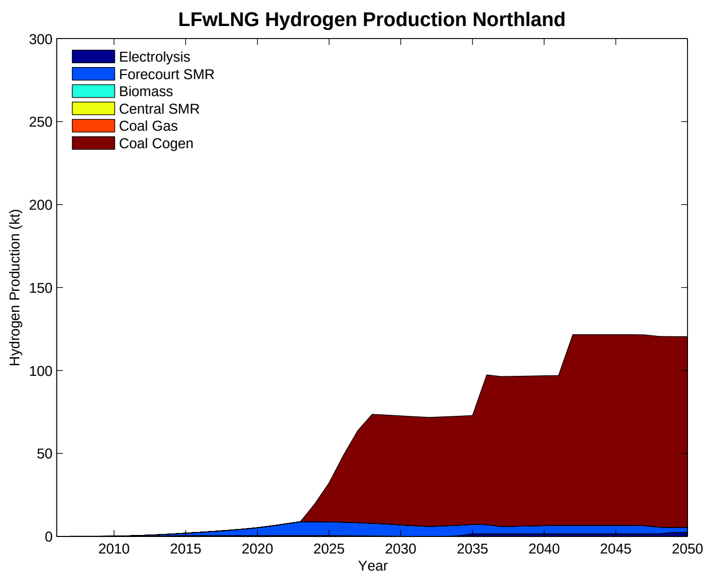







LFwLNG Hydrogen Production Hawke's Bay
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwLNG Hydrogen Production Nelson−Marlborough
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwLNG Hydrogen Production Northland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
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100
150
200
250
300
2010
2015
2020
2025
2030
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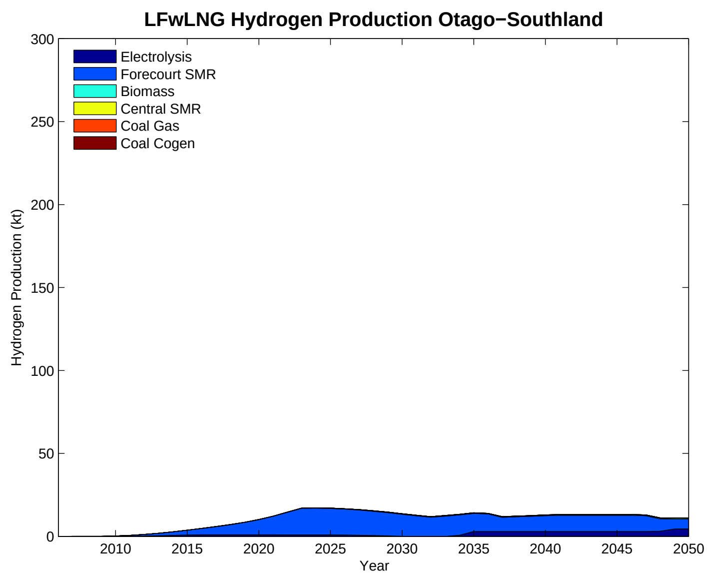
2040
2045
2050


LFwLNG Hydrogen Production Otago−Southland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
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100
150
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250
300
2010
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2020
2025
2030
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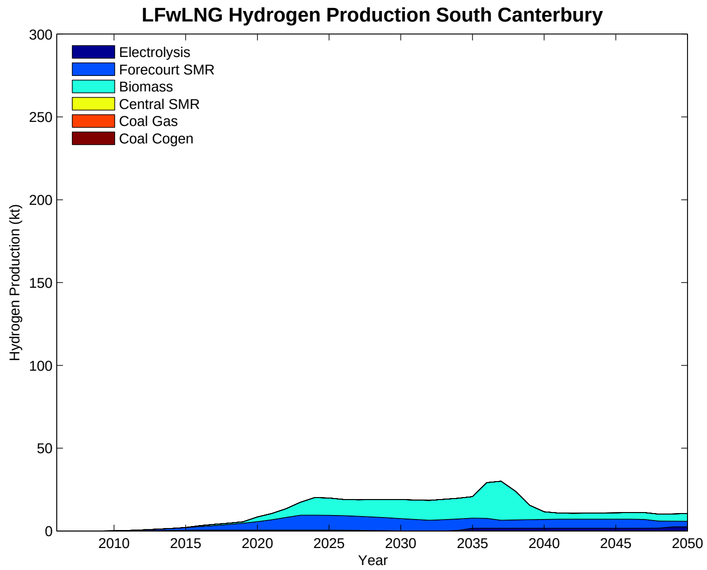
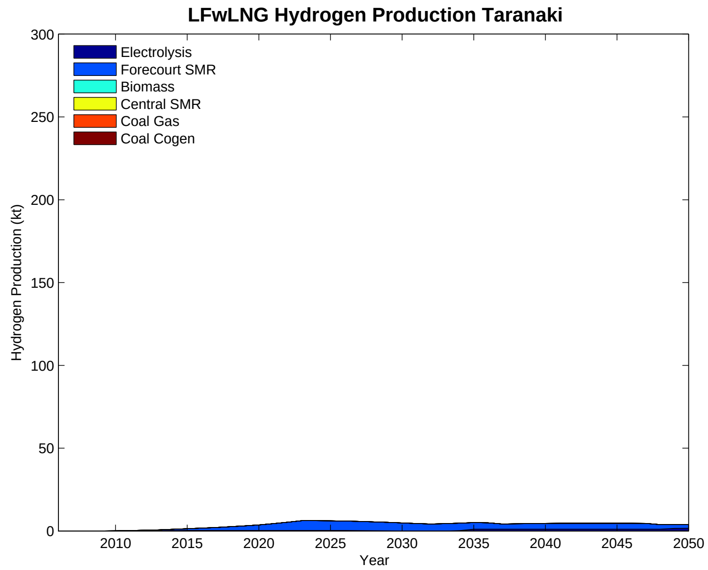
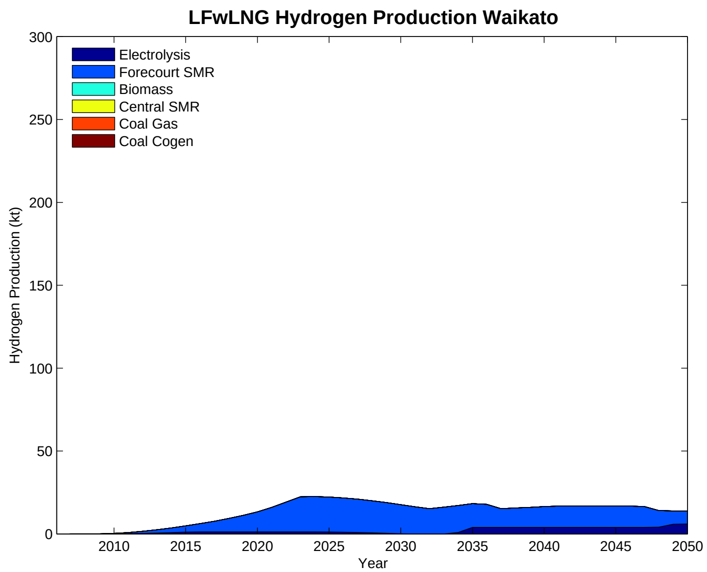
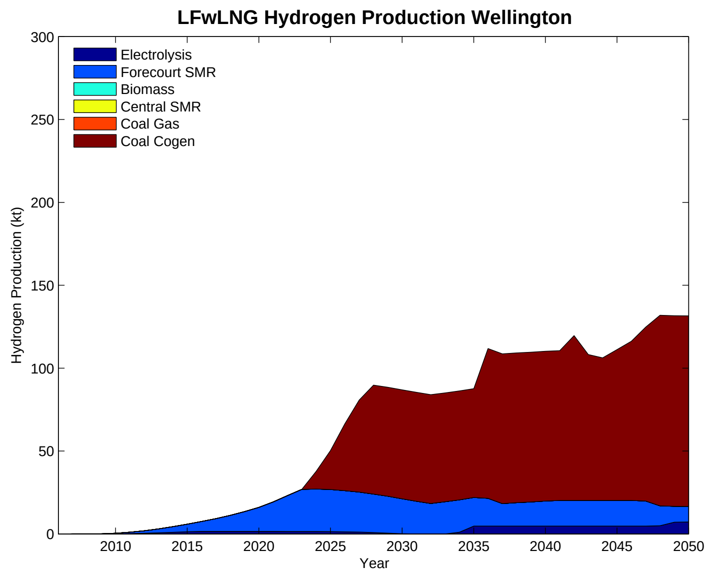
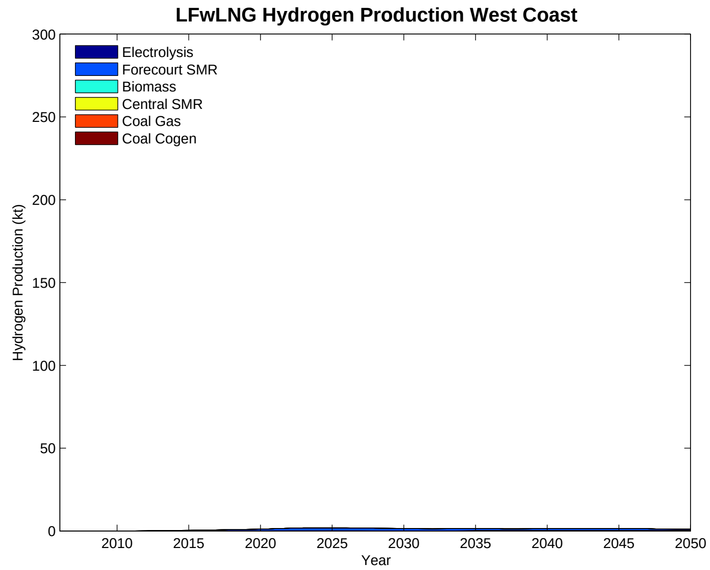
2045
2050


LFwLNG Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

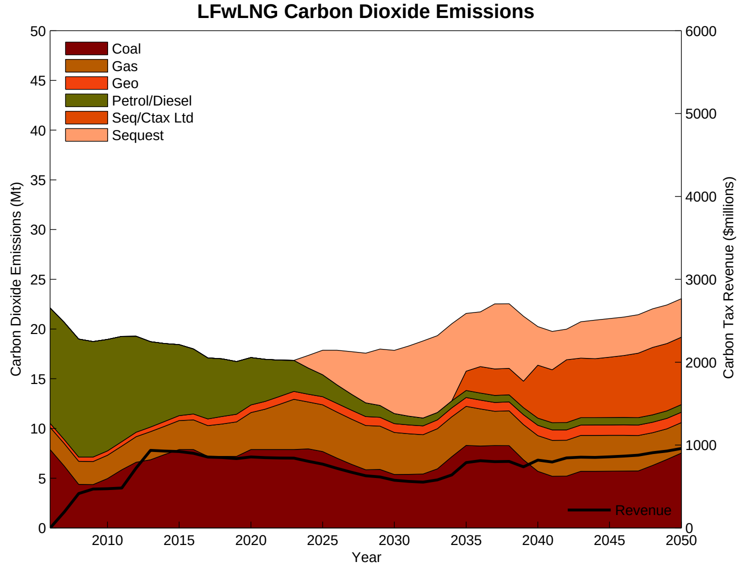

LFwLNG Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

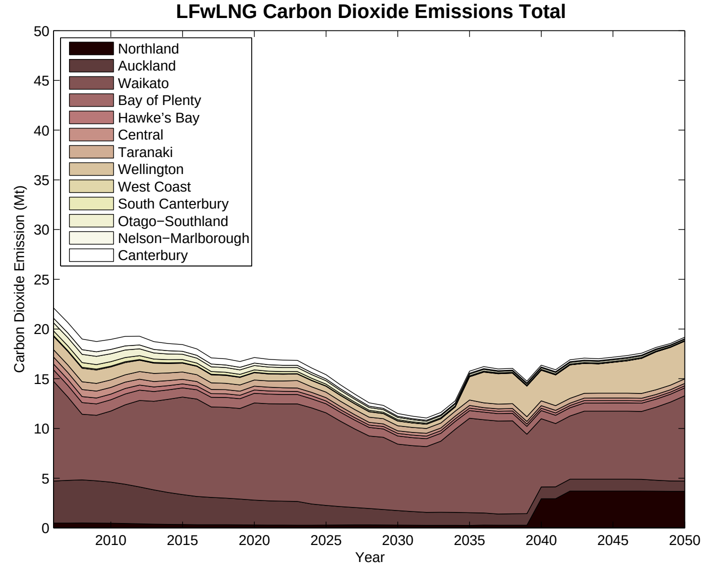

LFwLNG Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

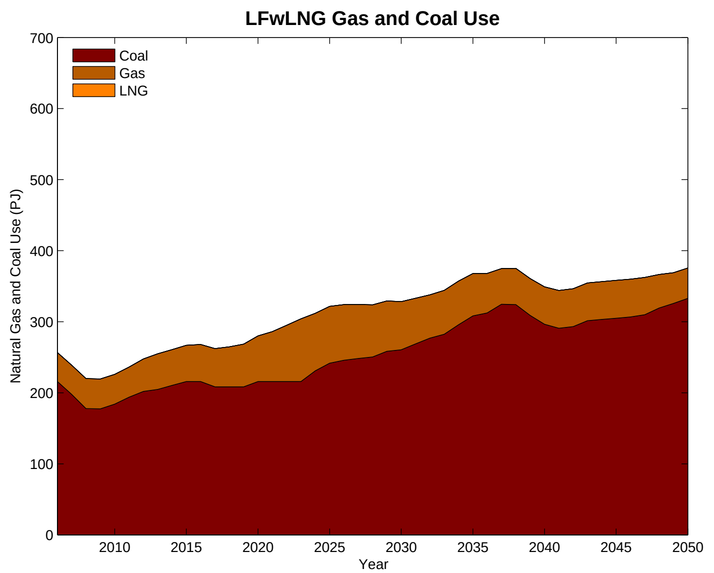

LFwLNG Hydrogen Production Wellington
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

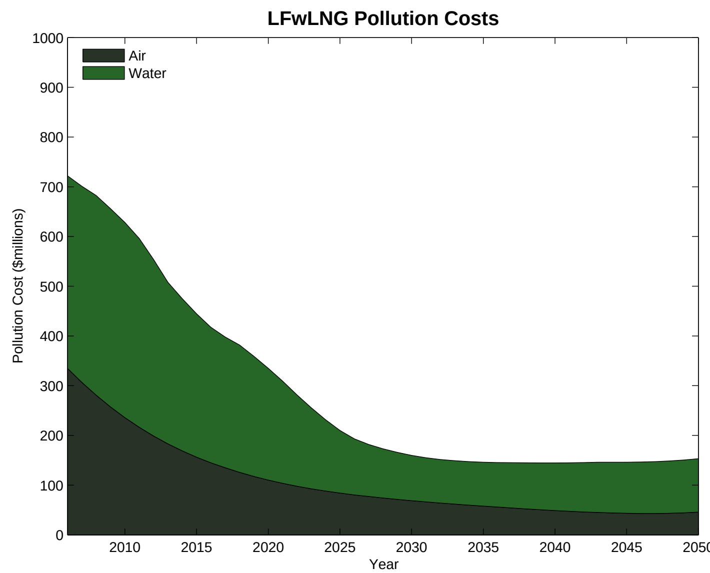

LFwLNG Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
300
250
200
150
100
50
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

Carbon Emissions - Energy Consumption and Pollution

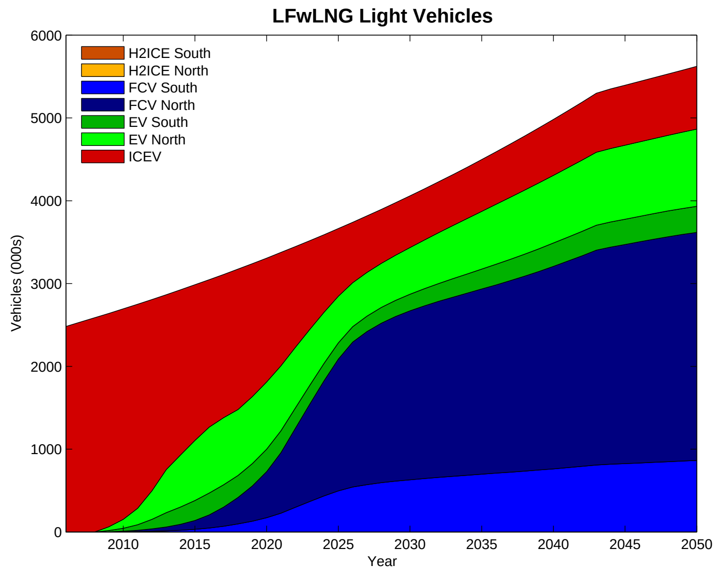


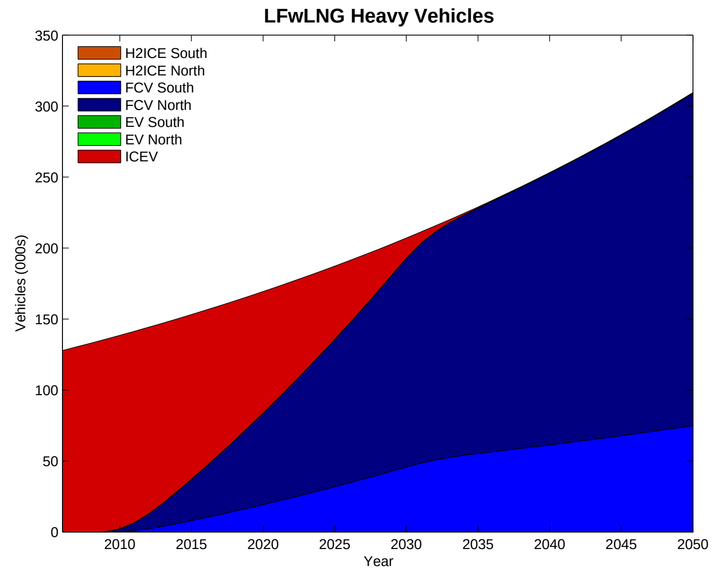


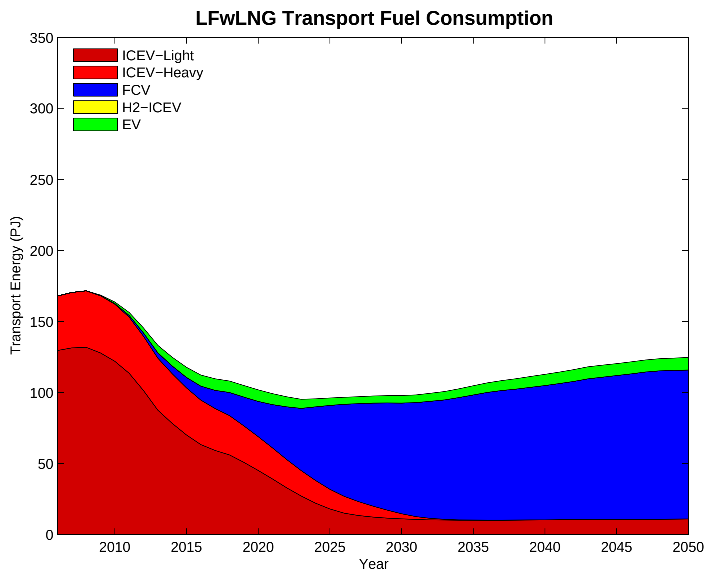




Transportation Sector





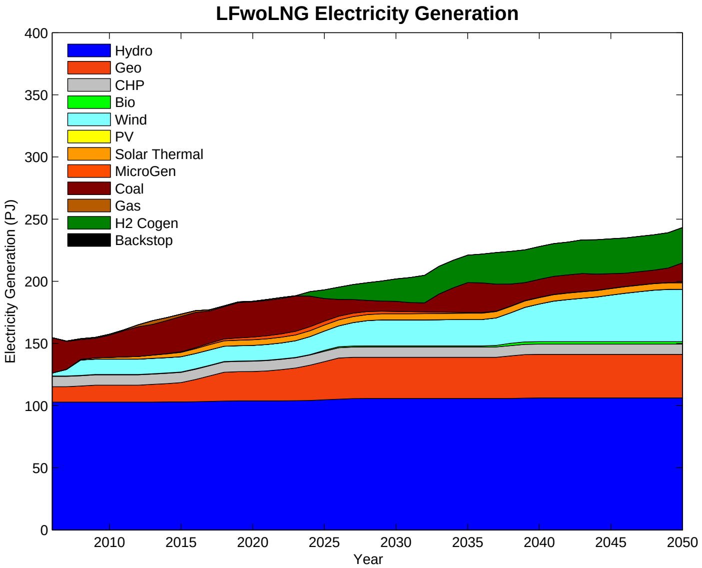


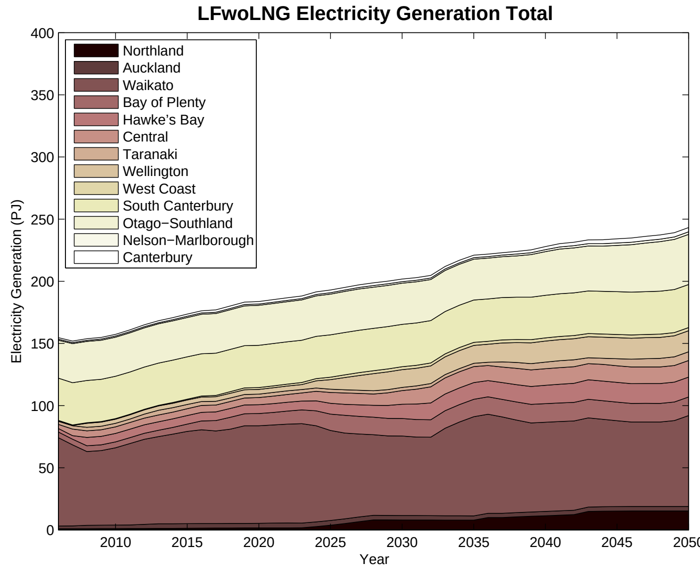
29 Scenario: Laissez-faire without LNG

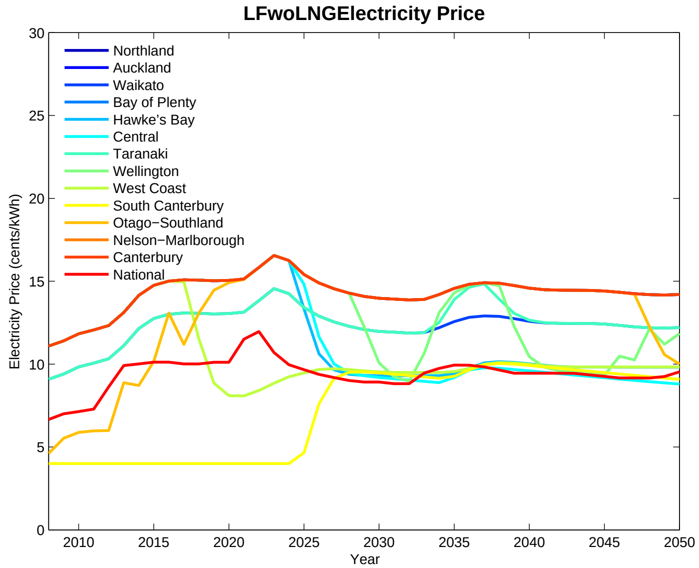
Key results for this scenario are:

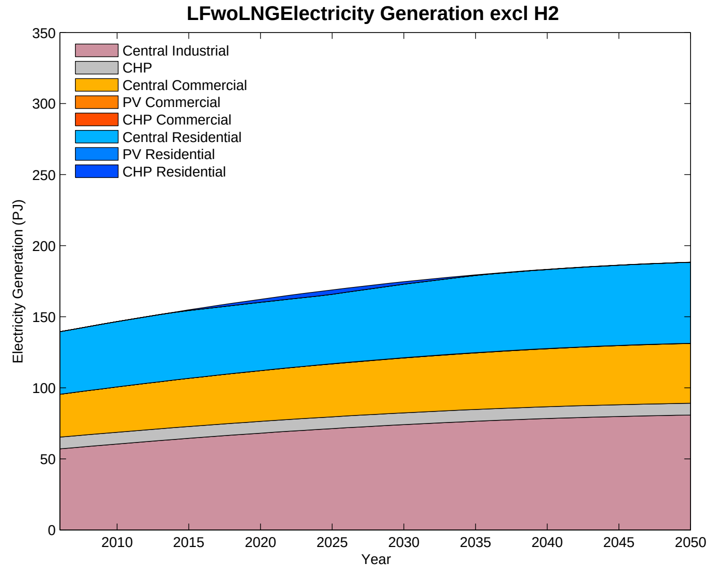
- National wholesale electricity price rises to 9.9 c/kWh in 2013 due the impact of the carbon tax. After 2020 it averages 9.6 c/kWh.
- CO_2 emissions in 2050 are 32% below 2006 levels with 23% of total emissions being sequestered. A further 35% of emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 85% in 2025 and 82% in 2050.
- Hydrogen generation in 2050 consists of 16% electrolysis, 10% forecourt SMR, 28% biomass gasification, and 46% coal cogeneration.
- Primary fossil fuel energy use increases by 32% between 2006 and 2050.
- 64% of the light vehicle fleet switches to HFCVs by 2050 with 22% switching to EVs. HFCVs begin to enter the market in significant numbers after 2020 when growth is rapid due to the reducing capital cost of fuel cells and increasing oil price.
- The heavy vehicle fleet is entirely HFCVs by 2033.
- Air and water pollution costs reduce from $722 million in 2006 to $154 million in 2050.

The National Electricity Market

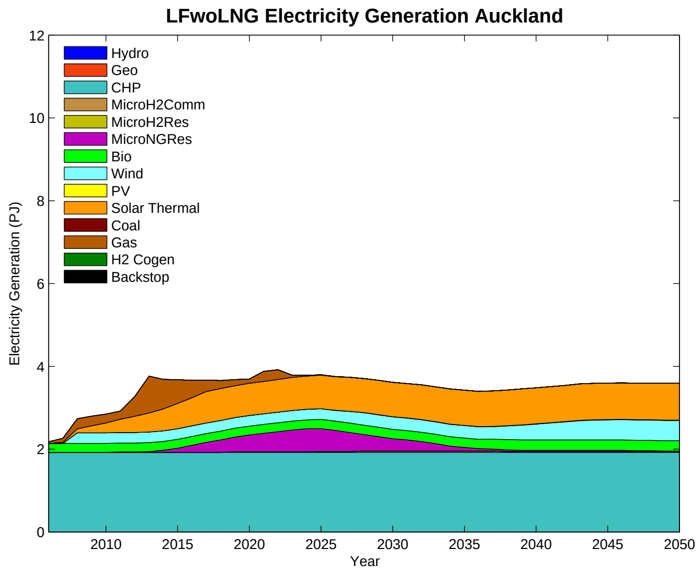


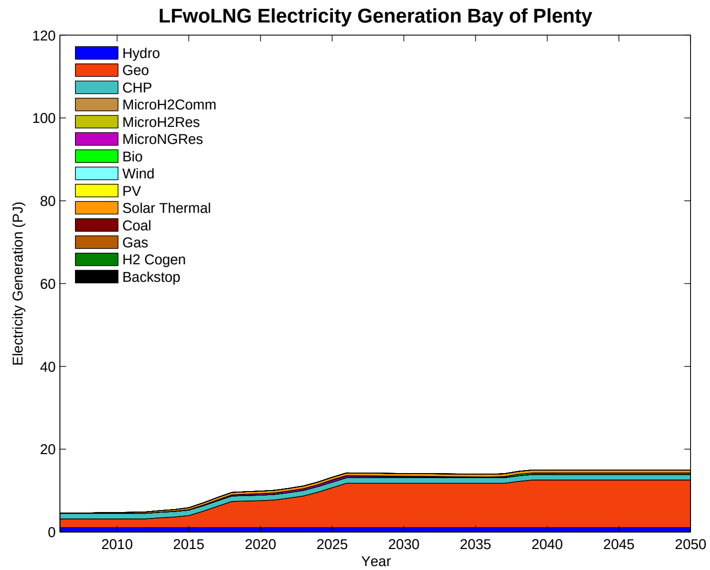


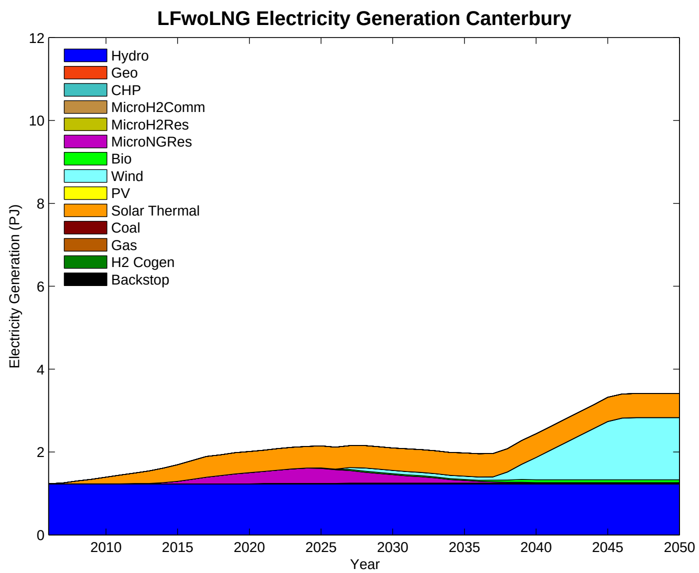


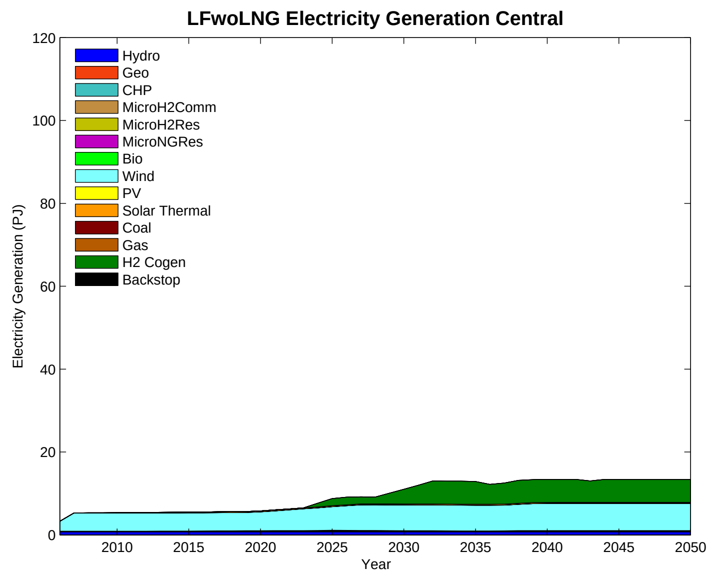


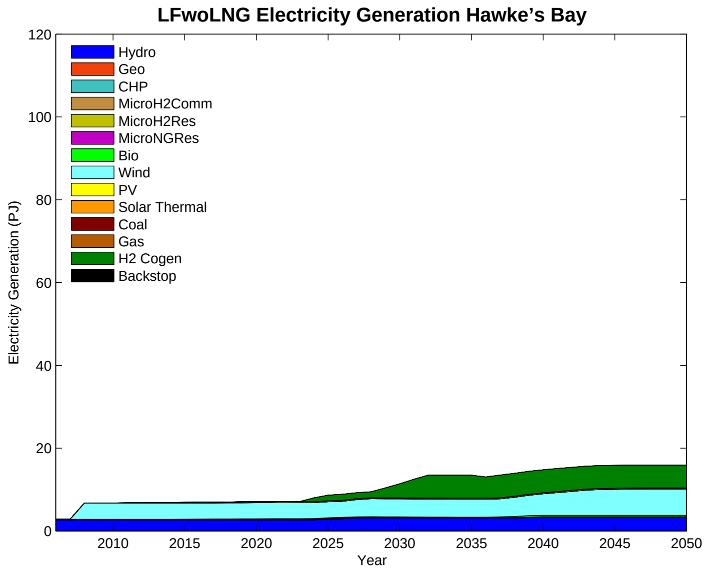
Regional Electricity Markets

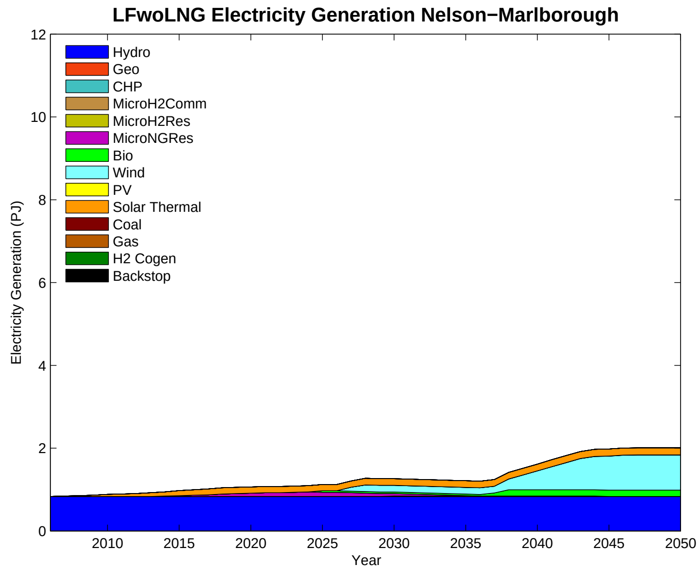


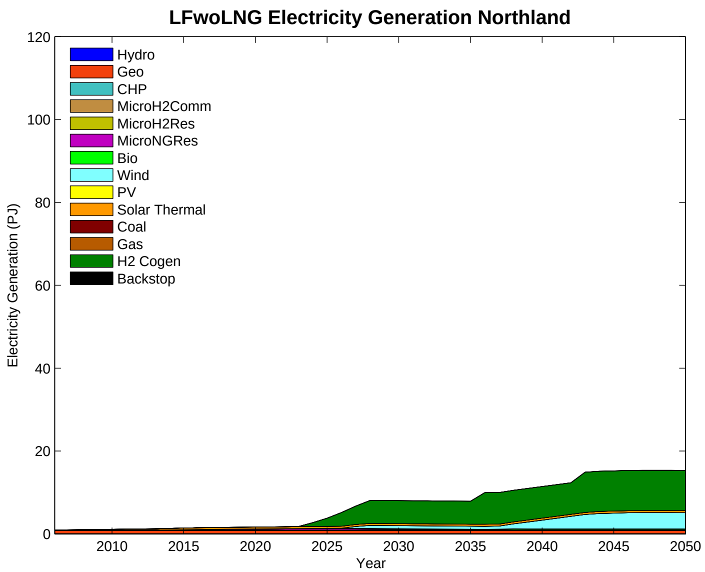


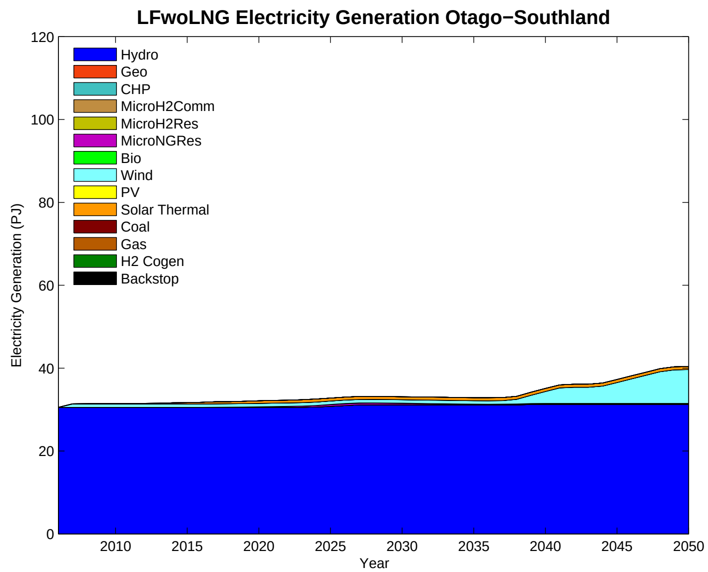


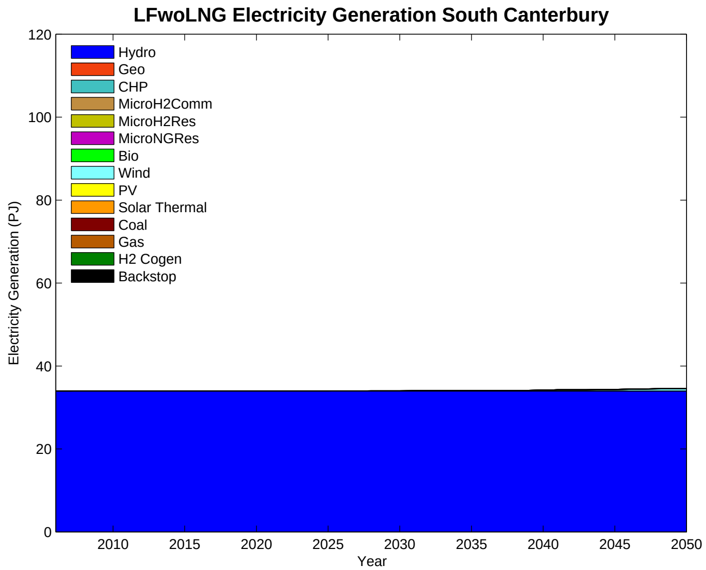


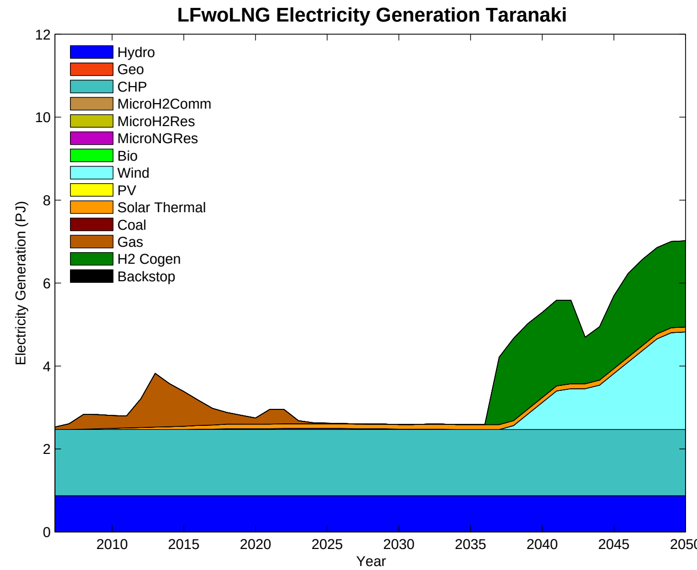

LFwoLNG Electricity Generation Hawke's Bay
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

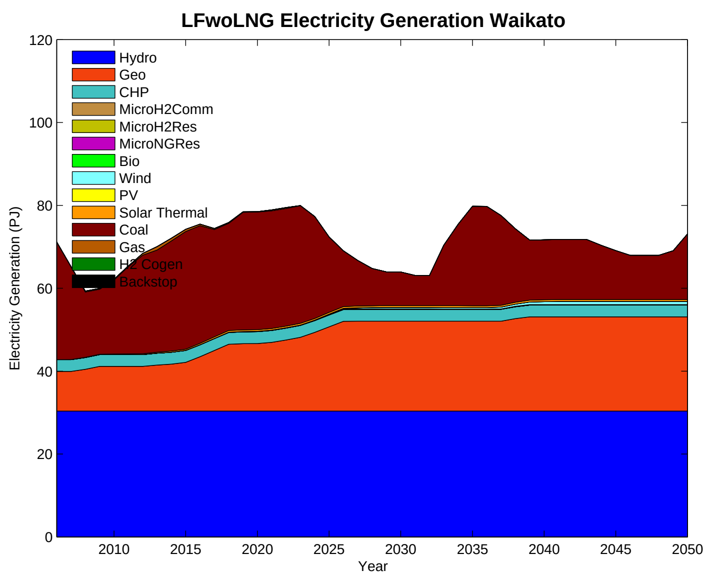

LFwoLNG Electricity Generation Nelson−Marlborough
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


LFwoLNG Electricity Generation Northland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


LFwoLNG Electricity Generation Otago−Southland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


LFwoLNG Electricity Generation South Canterbury
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year
0
20
40
60
80
100
120
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwoLNG Electricity Generation Taranaki
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwoLNG Electricity Generation Waikato
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year
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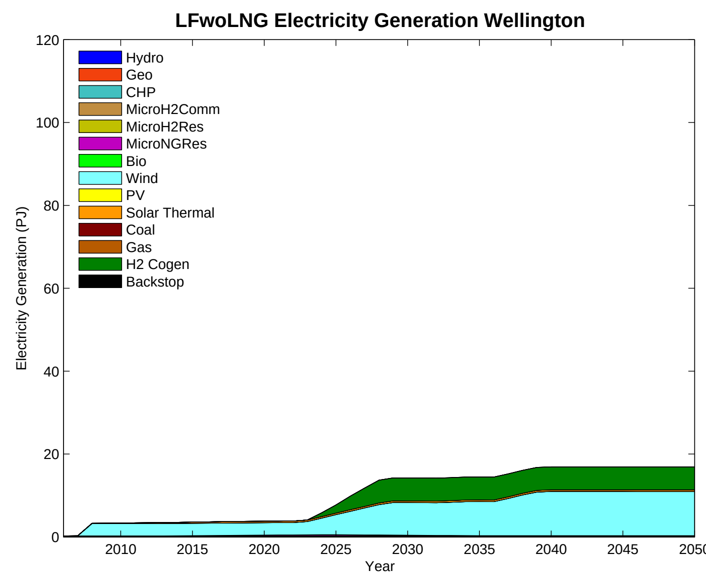
80
100
120
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwoLNG Electricity Generation Wellington
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year
0
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60
80
100
120
2010
2015
2020
2025
2030
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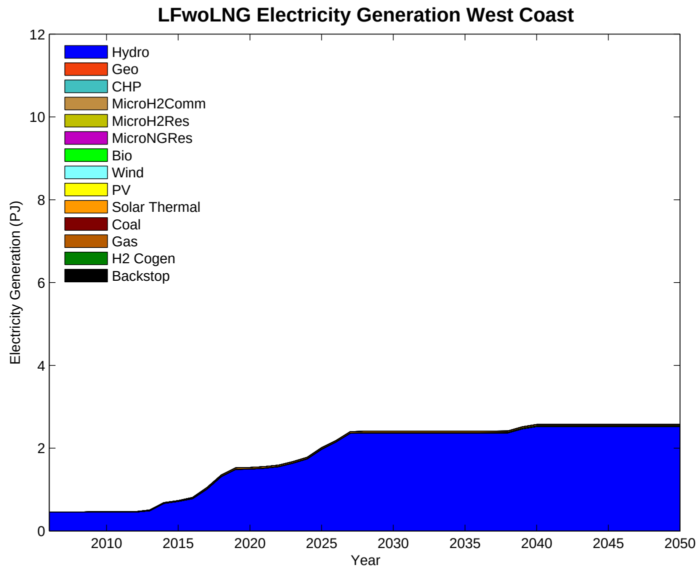
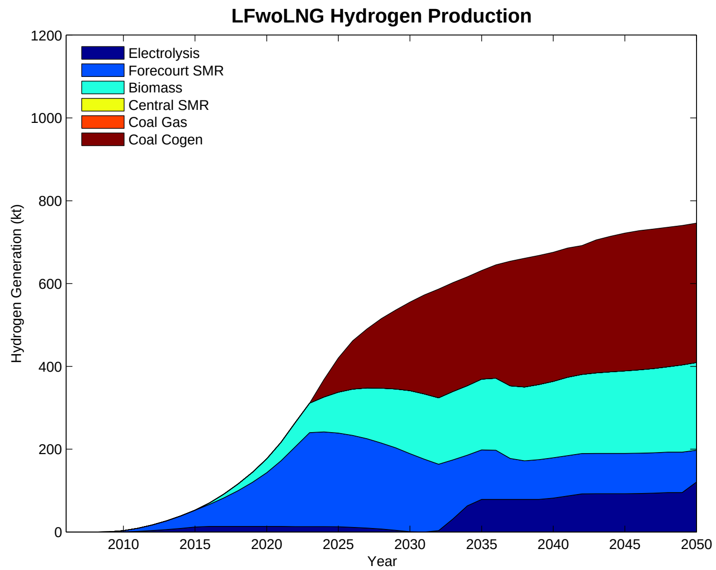
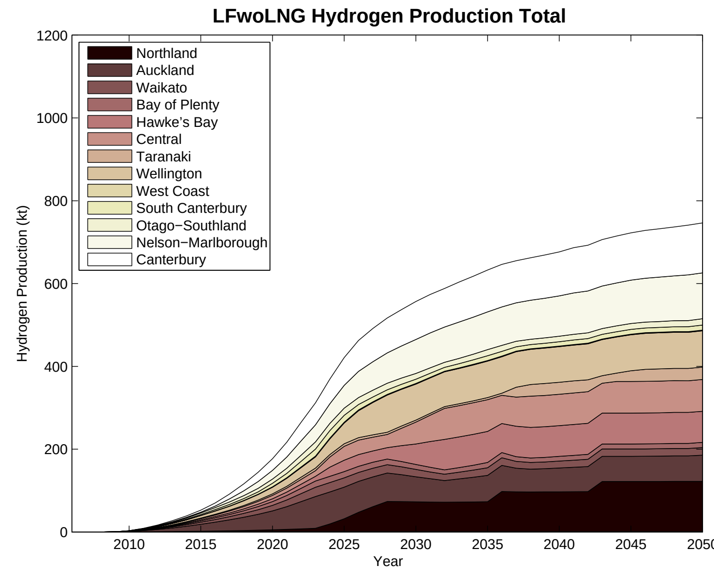
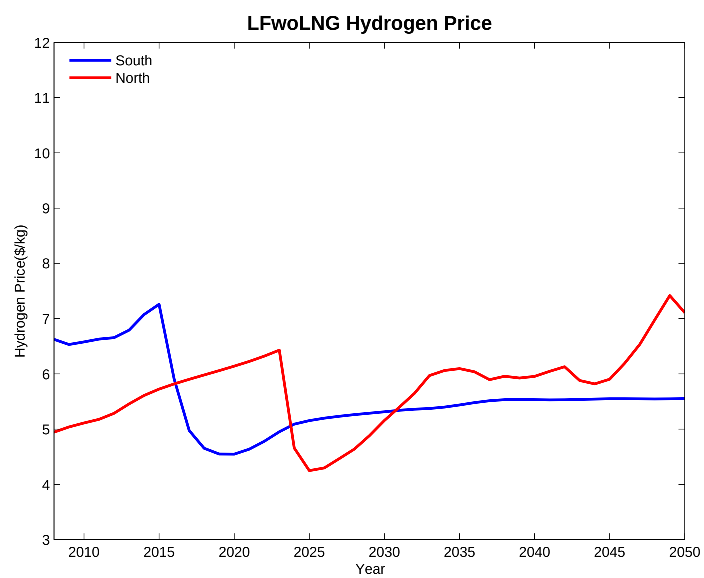
2040
2045
2050


LFwoLNG Electricity Generation West Coast
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

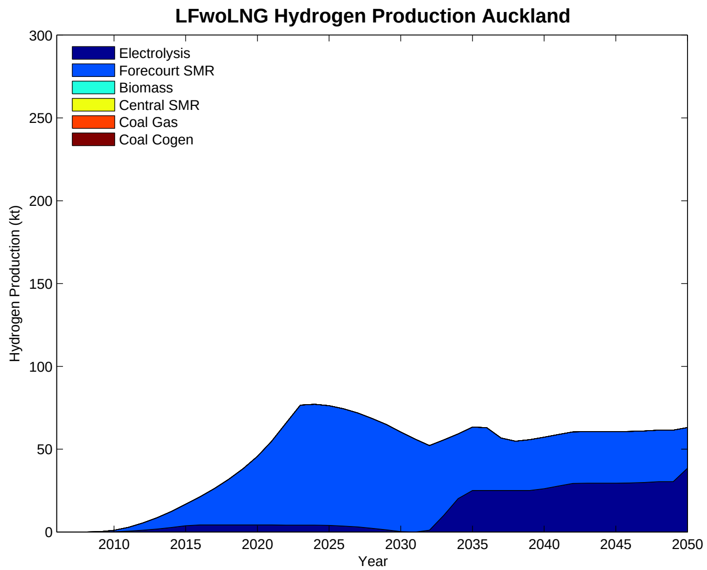
The National Hydrogen Market

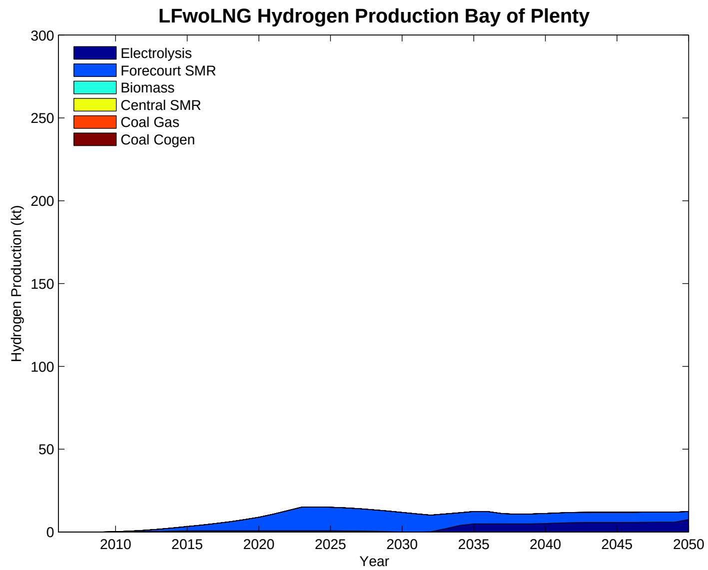


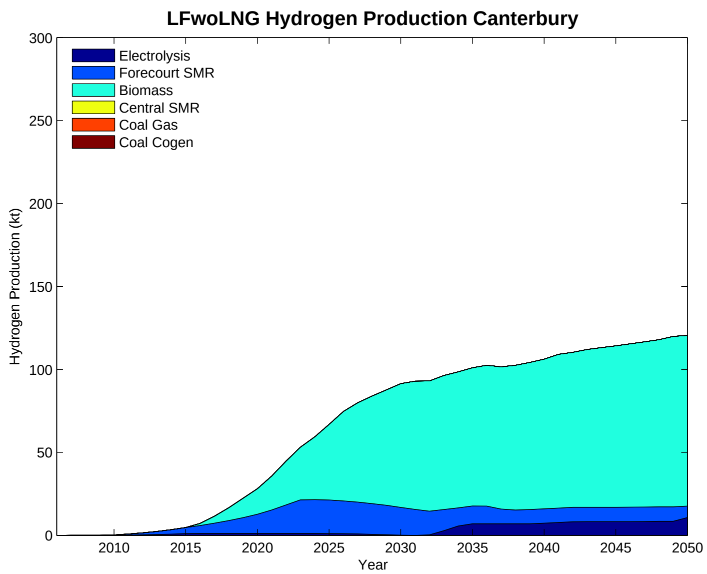


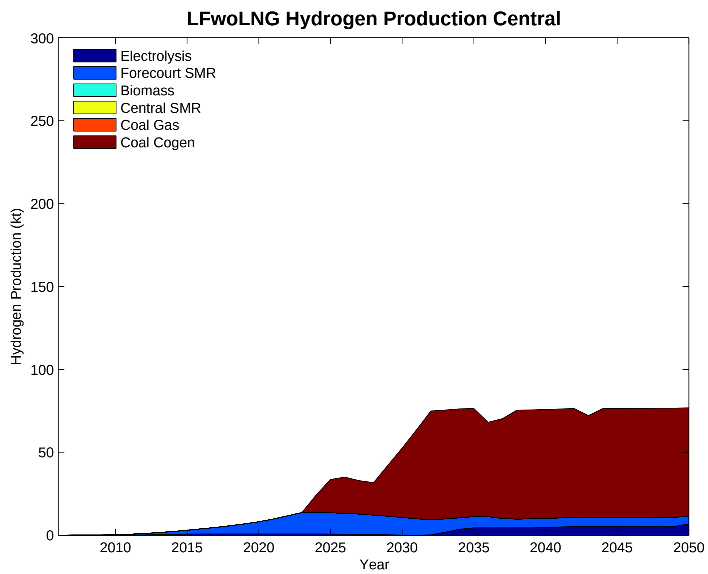


Regional Hydrogen Markets

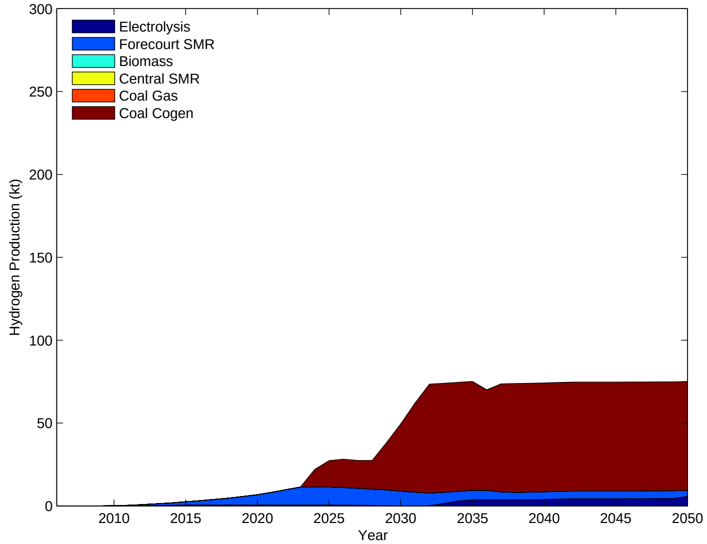




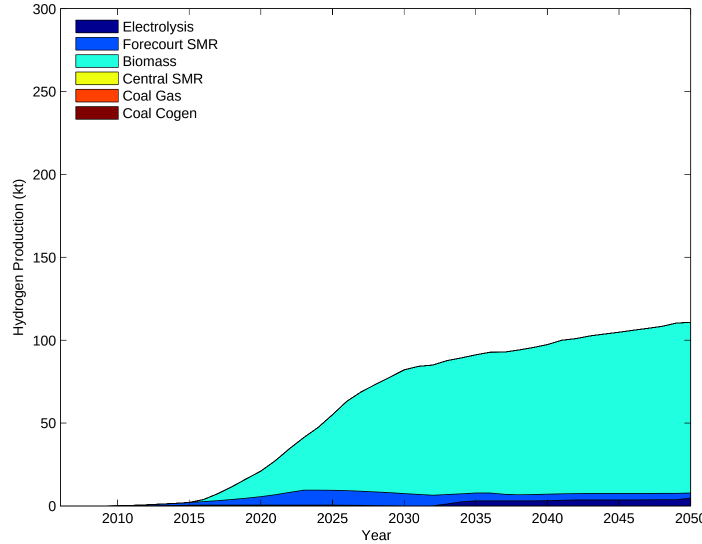




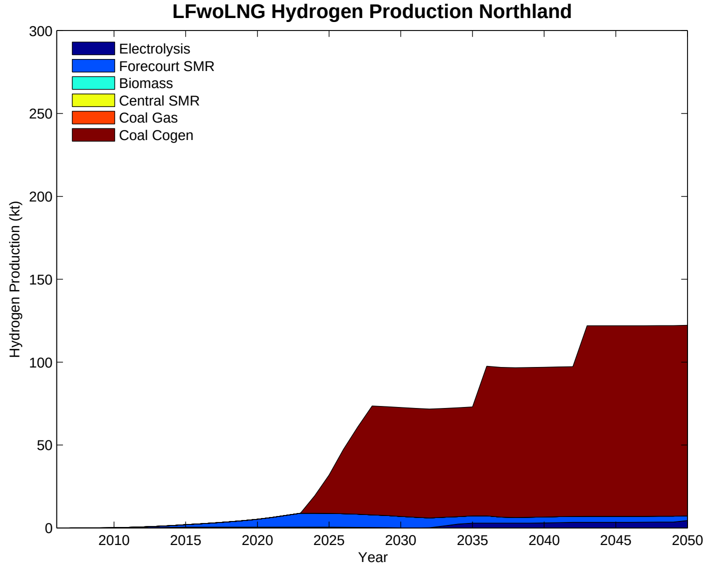
LFwoLNG Hydrogen Production Hawke's Bay



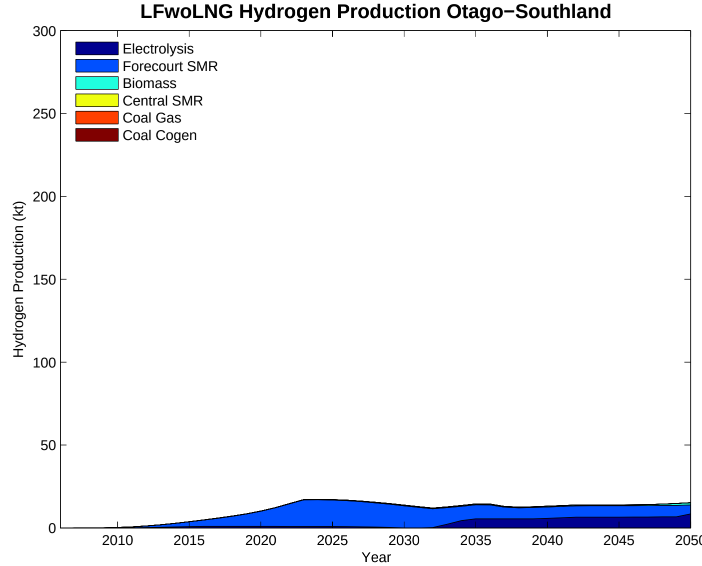
LFwoLNG Hydrogen Production Nelson−Marlborough

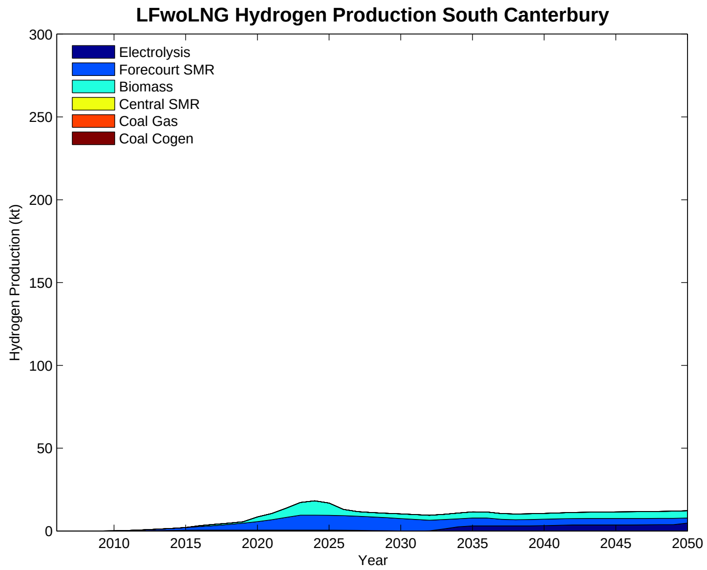


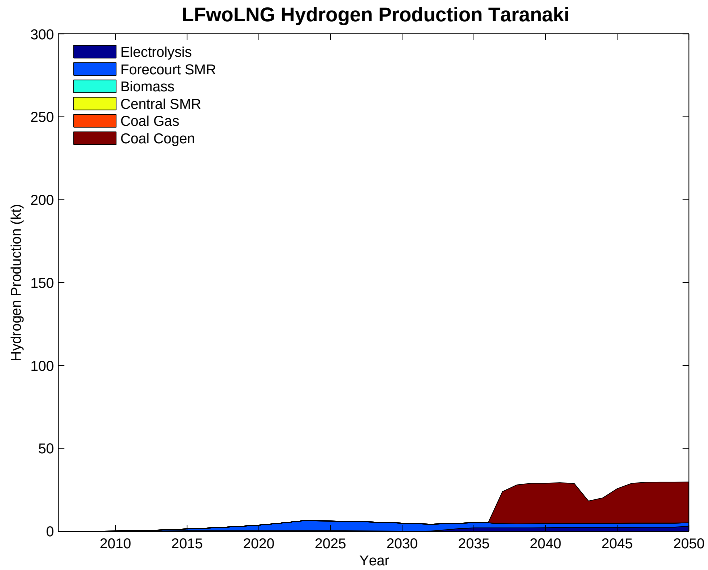
LFwoLNG Hydrogen Production Northland

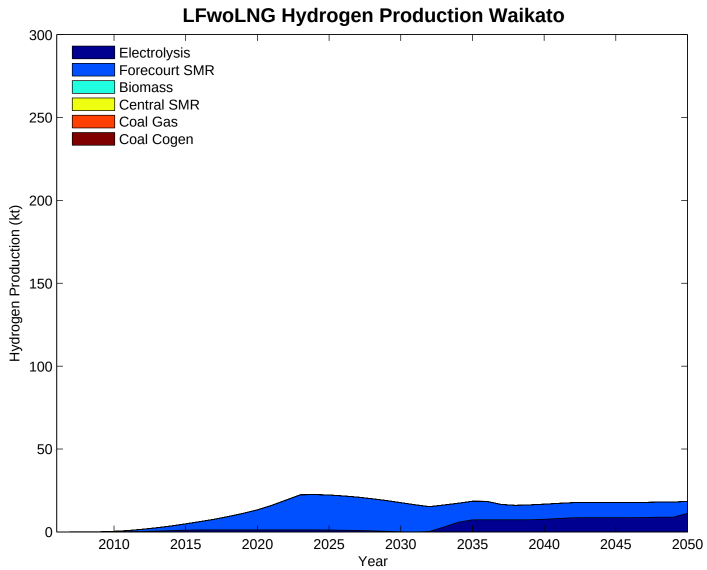


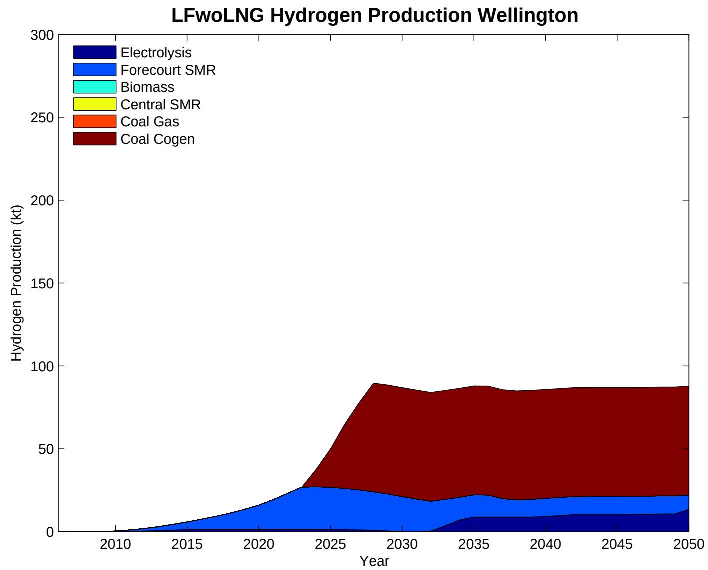
LFwoLNG Hydrogen Production Otago−Southland




LFwoLNG Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwoLNG Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwoLNG Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwoLNG Hydrogen Production Wellington
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
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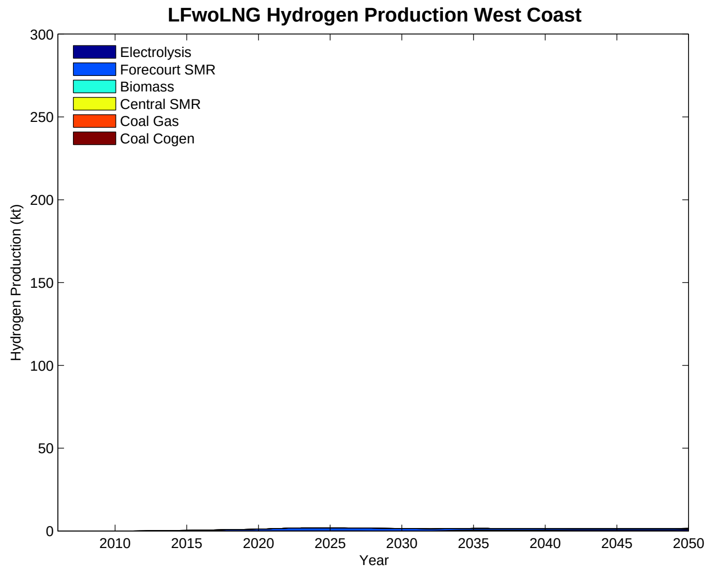
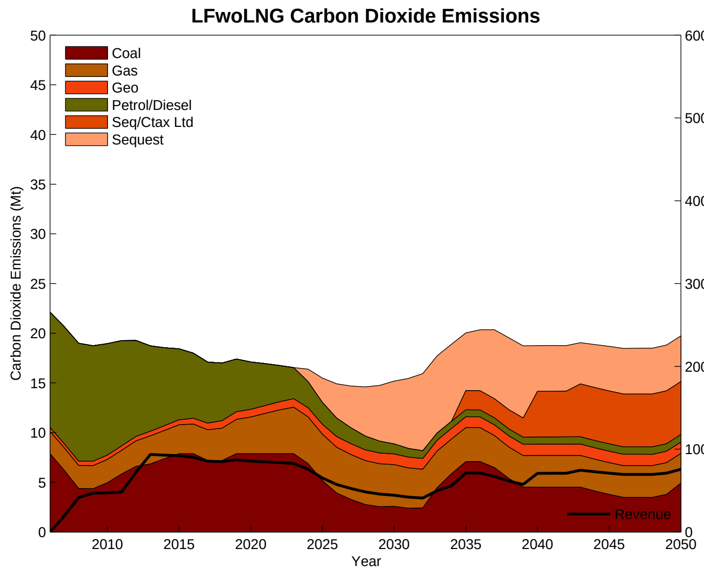
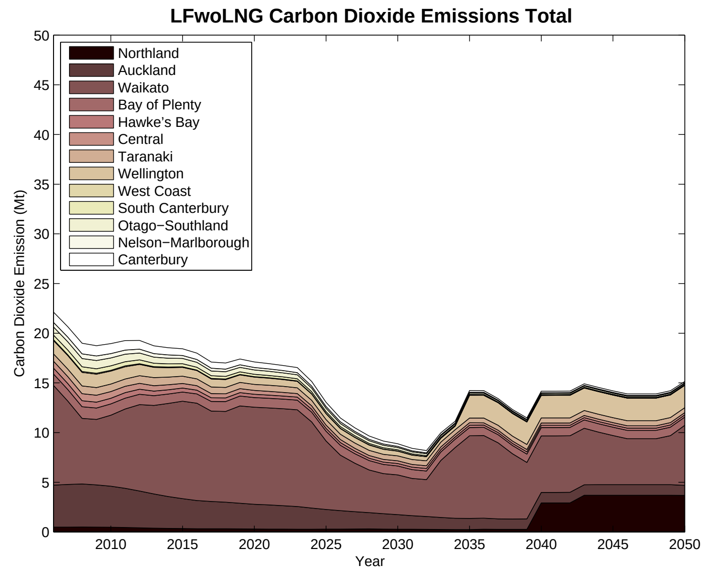
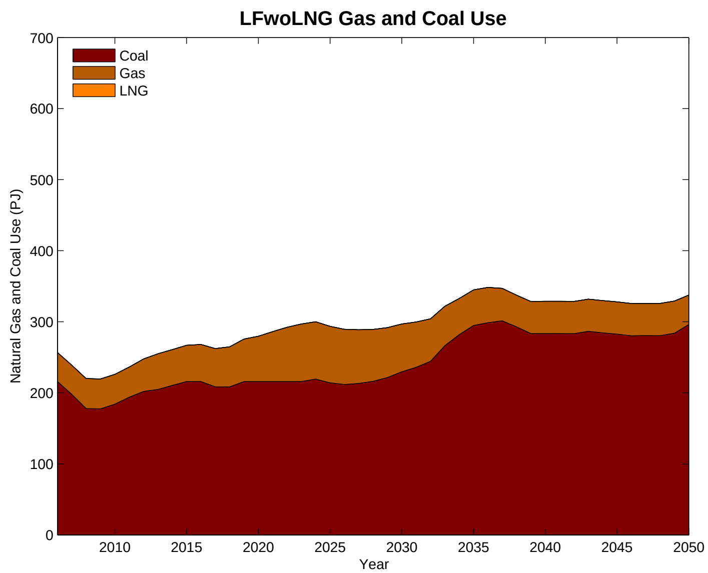
2050

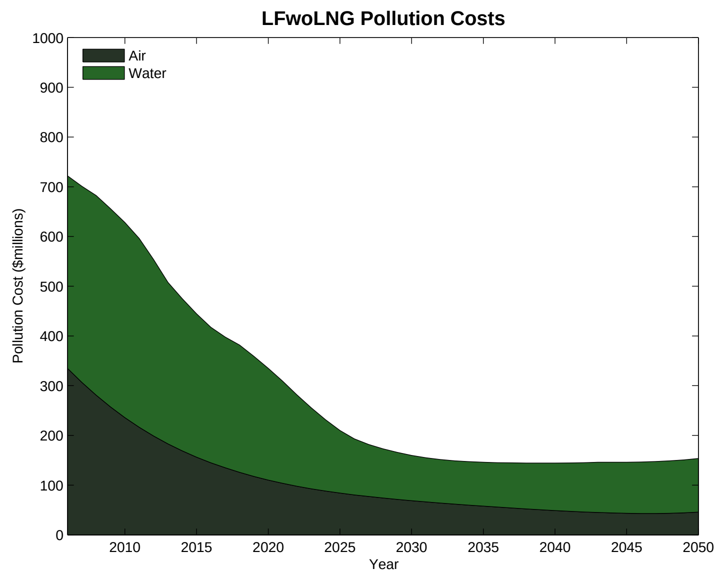

LFwoLNG Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
300
250
200
150
100
50
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

Carbon Emissions - Energy Consumption and Pollution

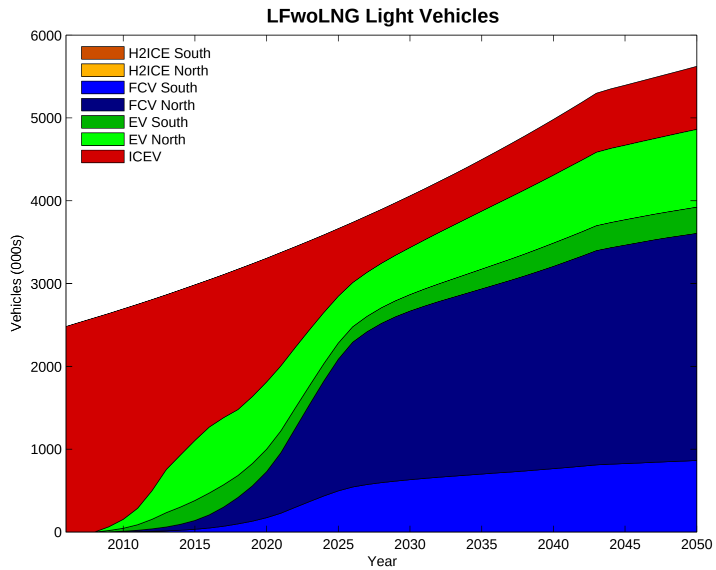


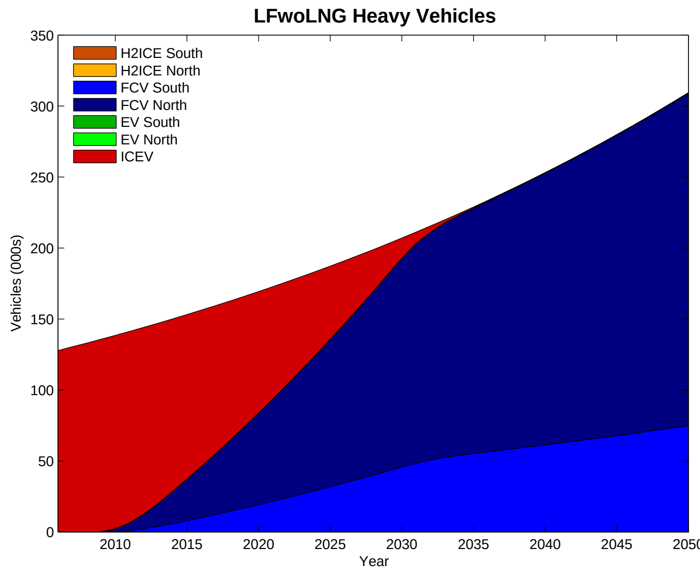


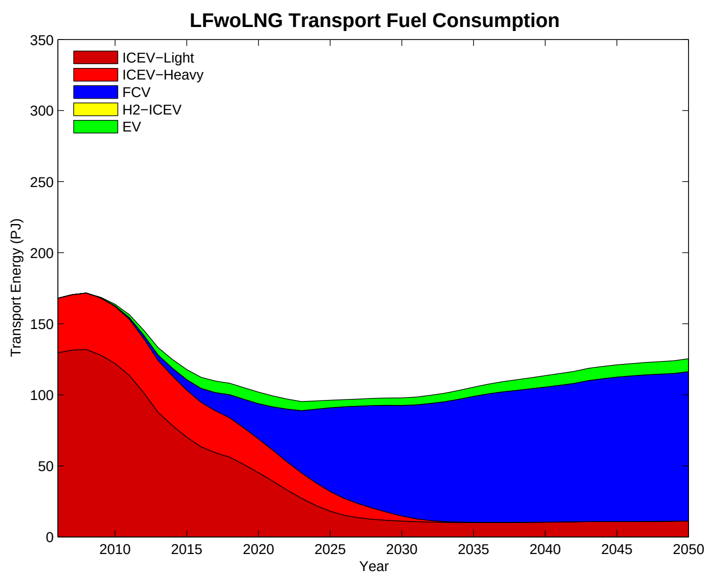




Transportation Sector





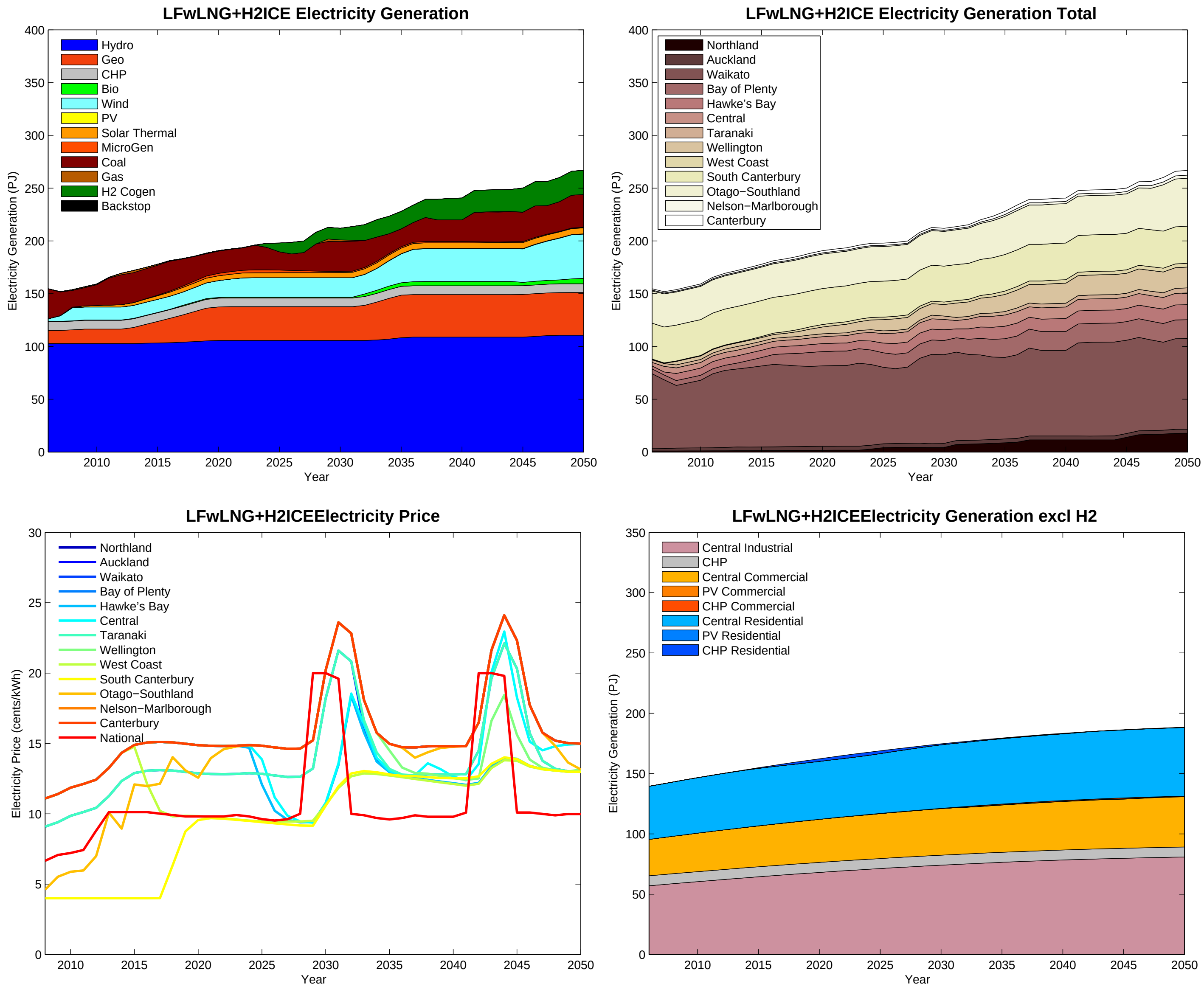


30 Scenario: Laissez-faire with H_2ICEVs

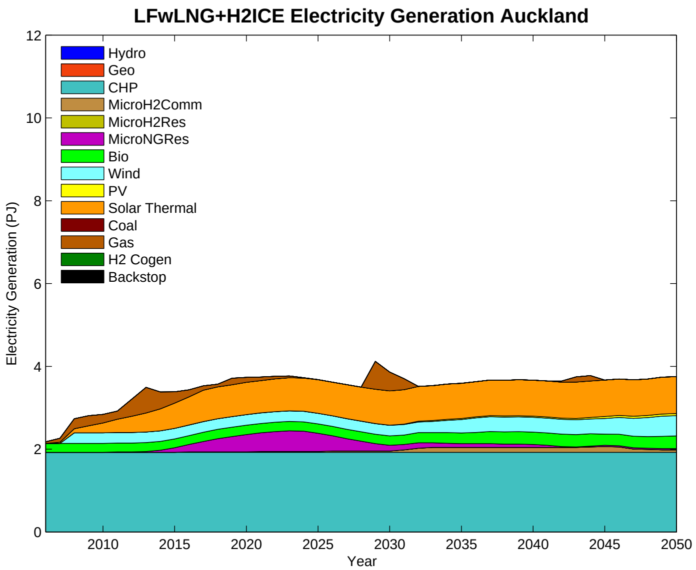
Key results for this scenario are:

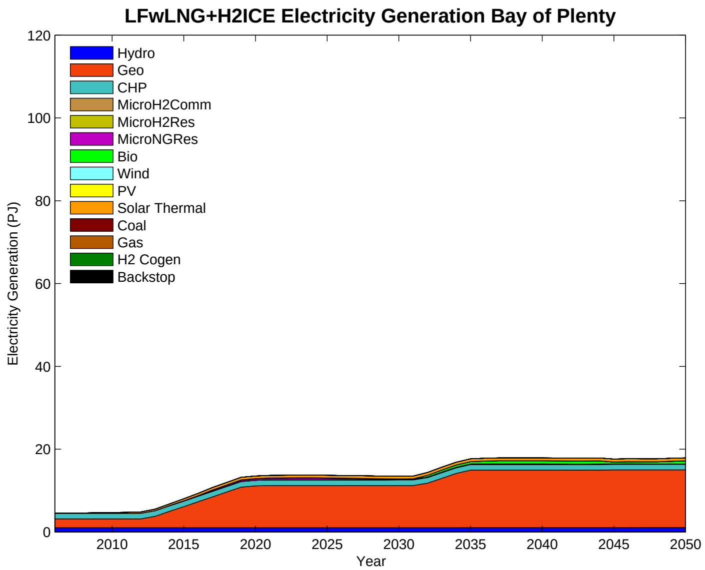
- National wholesale electricity price rises to 10.1 c/kWh in 2013 due the impact of the carbon tax. After 2020 it averages 11.8 c/kWh to 2050. There are electricity shortages in 2028-2031 and 2041-2044 with a peak of 20 c/kWh due to the electricity demand of producing hydrogen by electrolysis.
- CO_2 emissions in 2050 are 13% below 2006 levels with 10% of total emissions being sequestered. A further 31% of emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 86% in 2025 and 80% in 2050.
- Hydrogen generation in 2050 consists of 28% electrolysis, 11% forecourt SMR, 30% biomass gasification, and 31% coal cogeneration.
- Primary fossil fuel energy use increases by 39% between 2006 and 2050.
- 60% of the light vehicle fleet switches to HFCVs by 2050 with a further 7% switching to H_2ICEVs and 20% switching to EVs. H_2ICEVs and HFCVs begin to enter the market in significant numbers in 2012 and 2020 respectively driven in the first instance by the rising oil price and in the second instance by the additional factor of the reducing capital cost of fuel cells.
- The heavy vehicle fleet is entirely HFCVs by 2033.
- Air and water pollution costs reduce from $722 million in 2006 to $154 million in 2050.

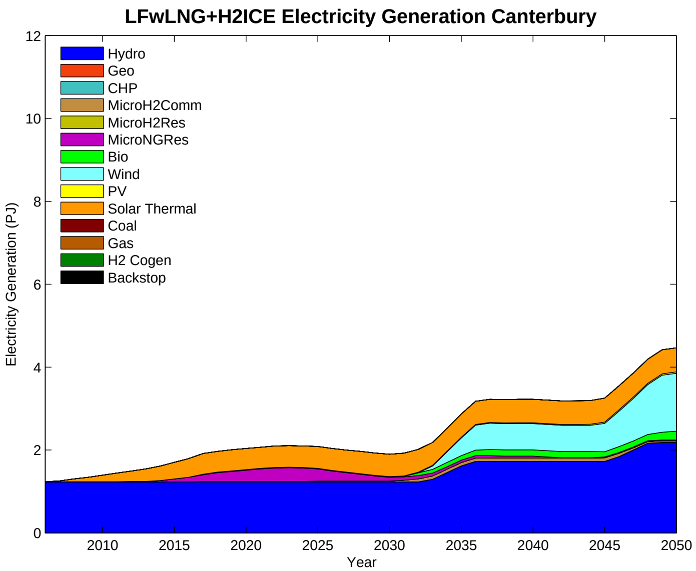
The National Electricity Market

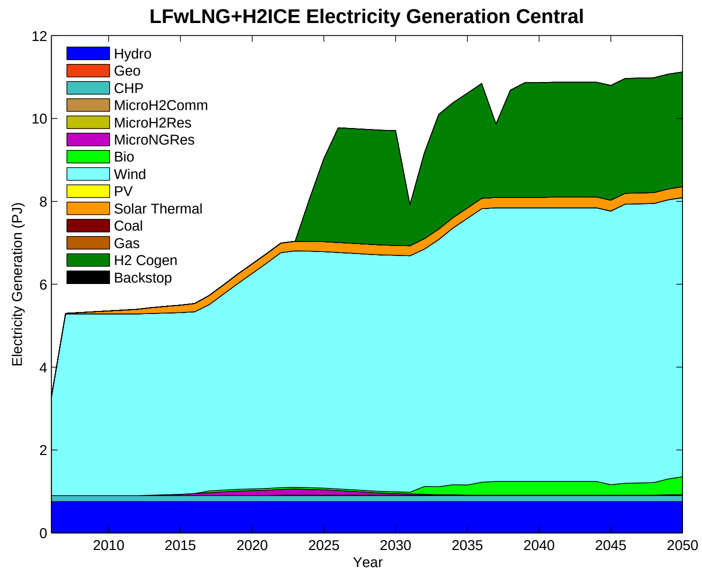


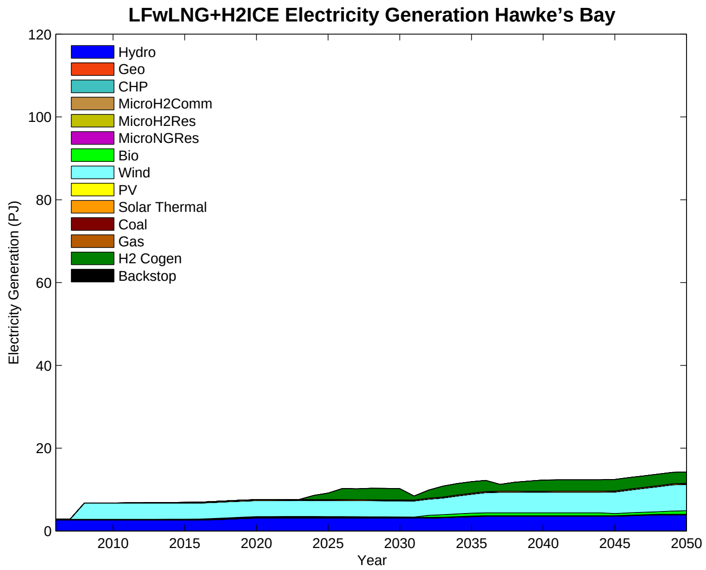
Regional Electricity Markets

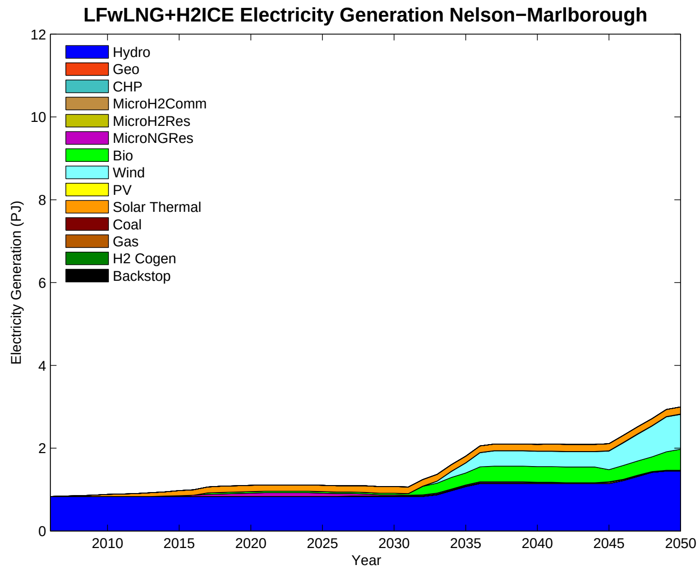


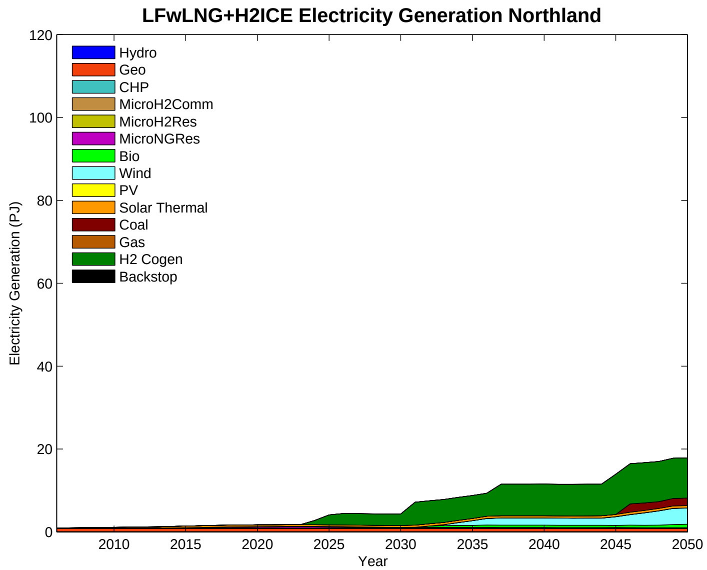


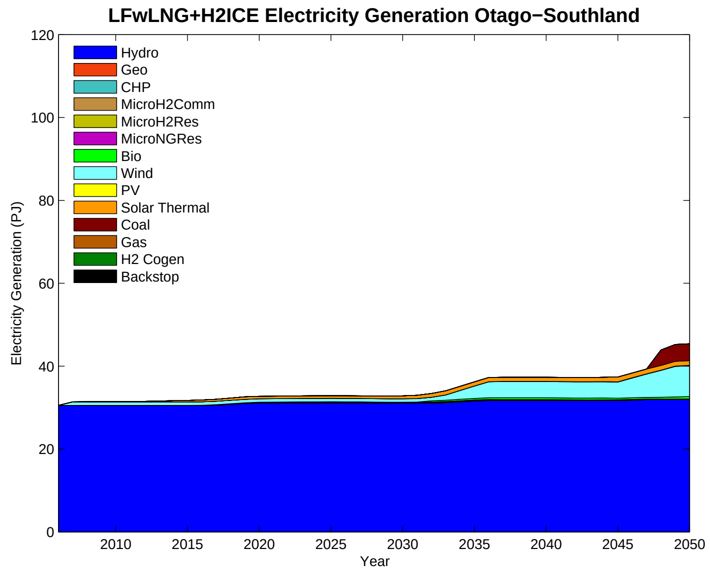


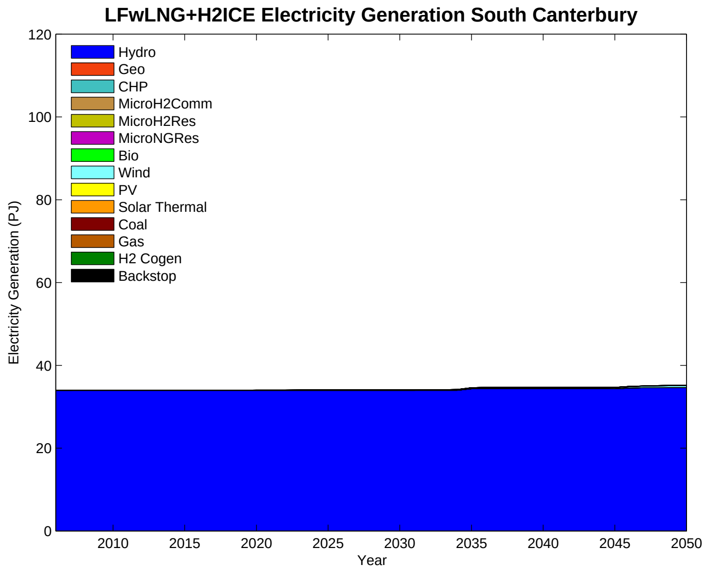


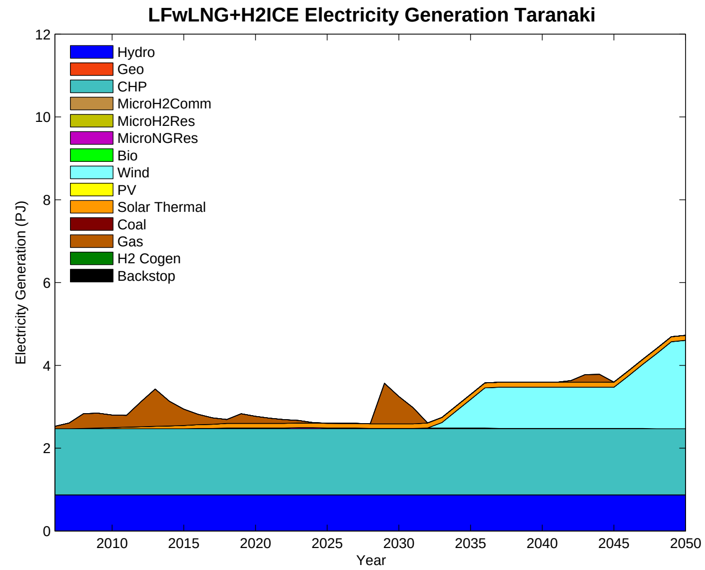

LFwLNG+H2ICE Electricity Generation Hawke's Bay
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

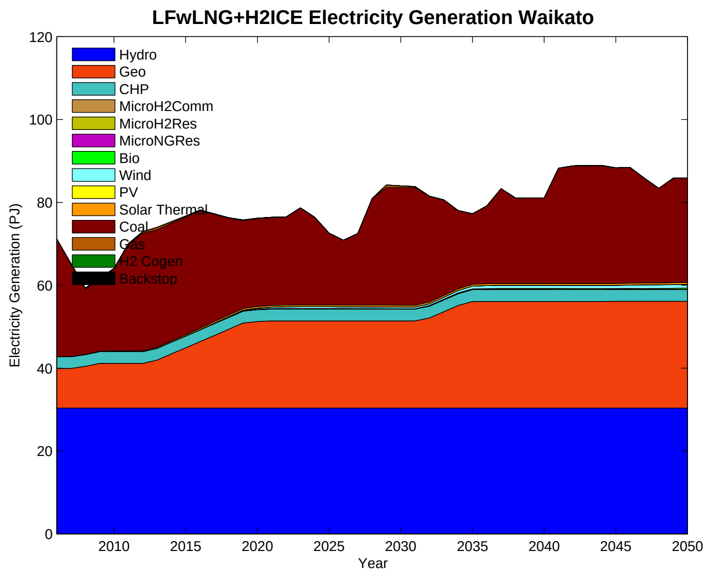

LFwLNG+H2ICE Electricity Generation Nelson−Marlborough
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

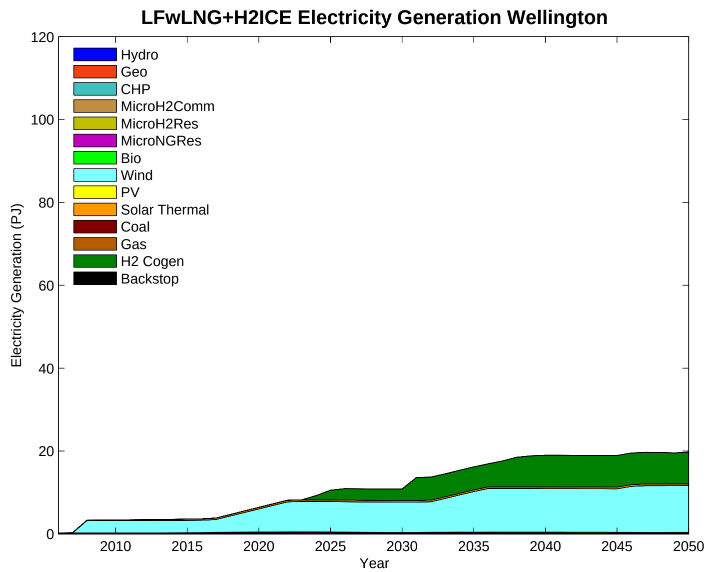

LFwLNG+H2ICE Electricity Generation Northland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

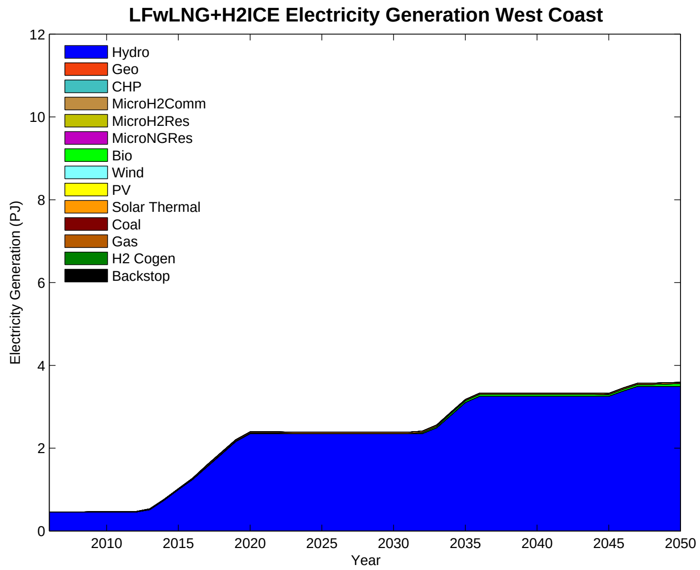

LFwLNG+H2ICE Electricity Generation Otago−Southland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


LFwLNG+H2ICE Electricity Generation South Canterbury
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

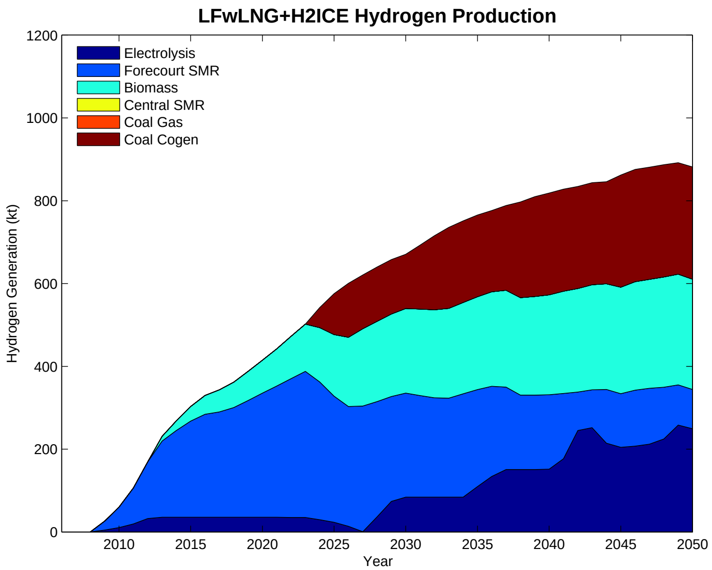

LFwLNG+H2ICE Electricity Generation Taranaki
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

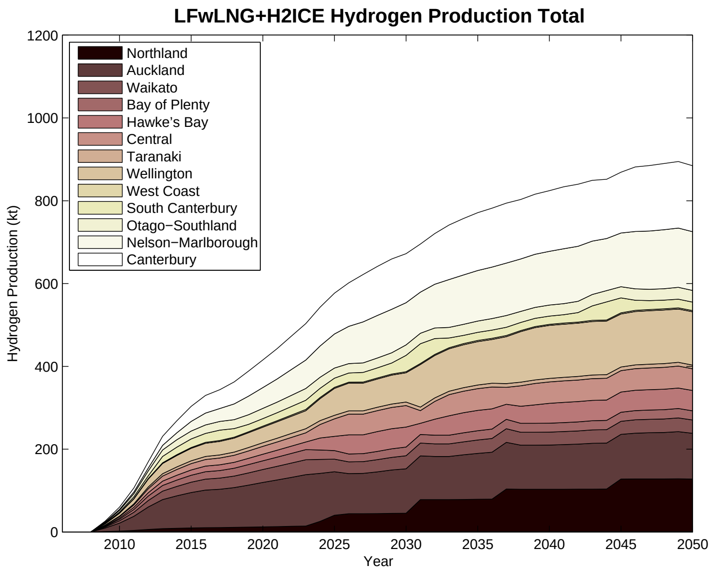

LFwLNG+H2ICE Electricity Generation Waikato
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

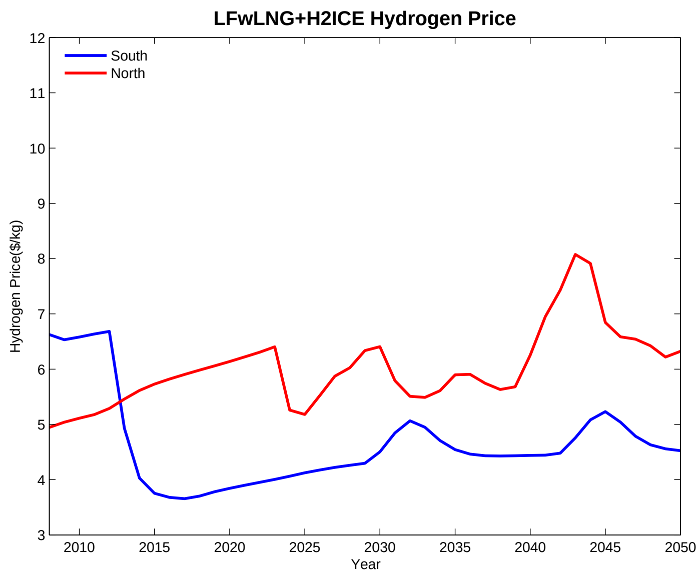

LFwLNG+H2ICE Electricity Generation Wellington
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


LFwLNG+H2ICE Electricity Generation West Coast
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050

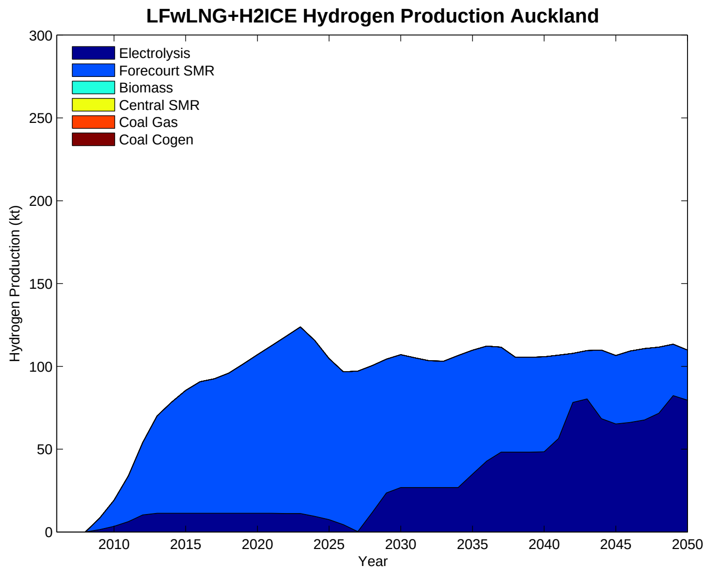
The National Hydrogen Market

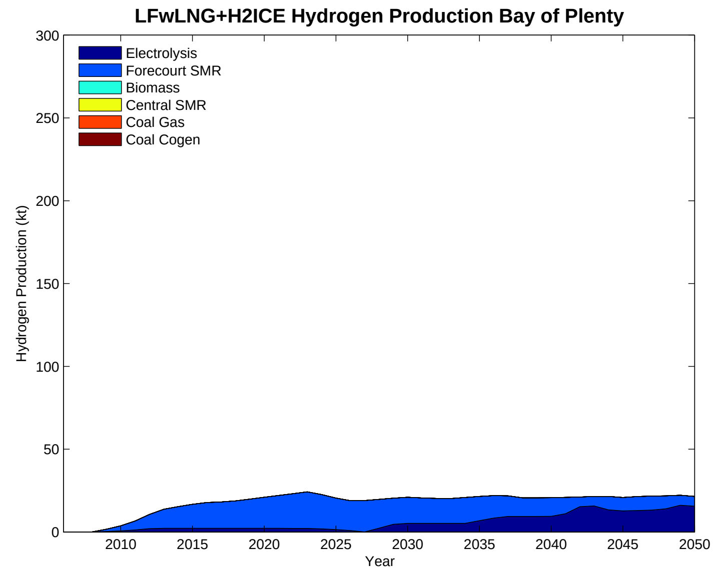


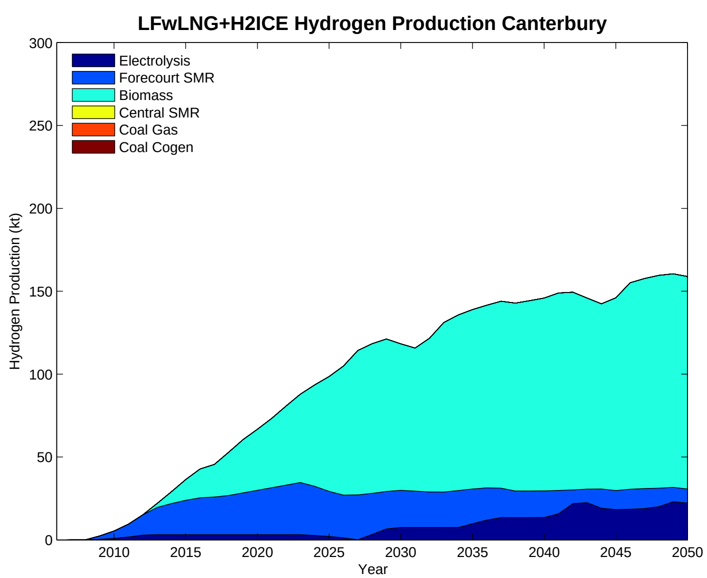


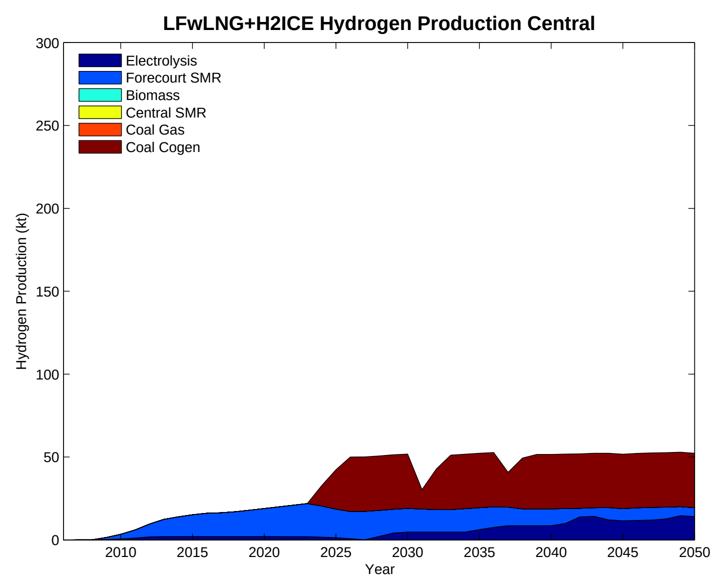


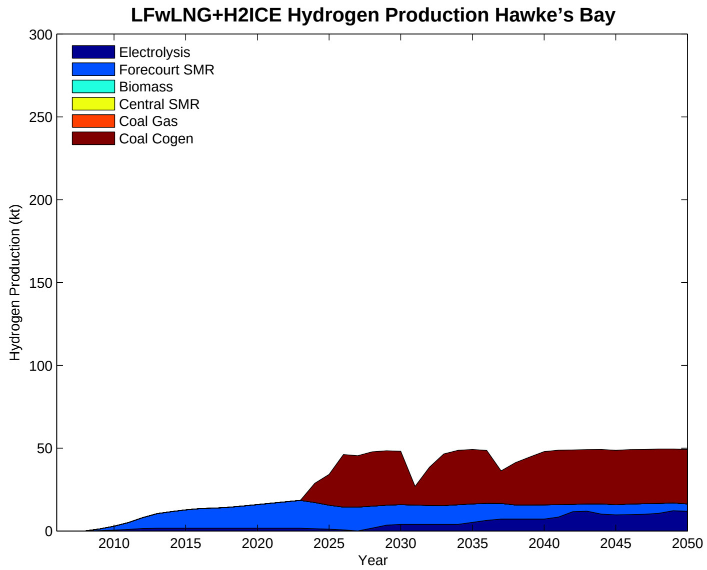
Regional Hydrogen Markets

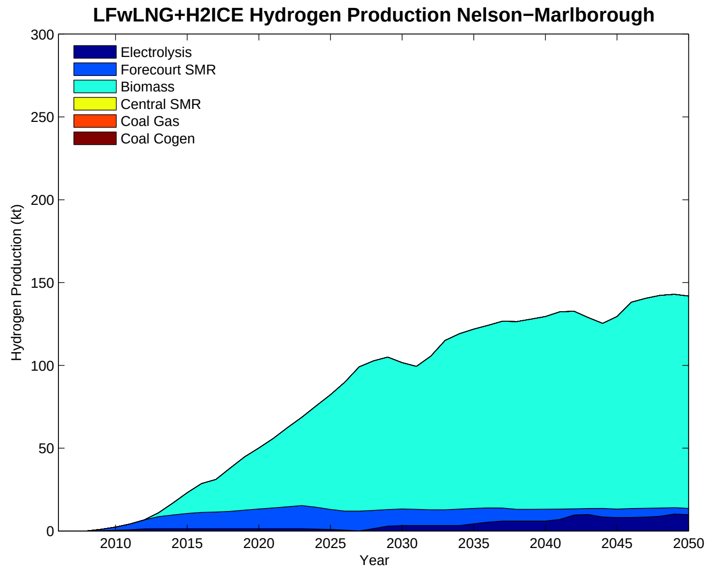


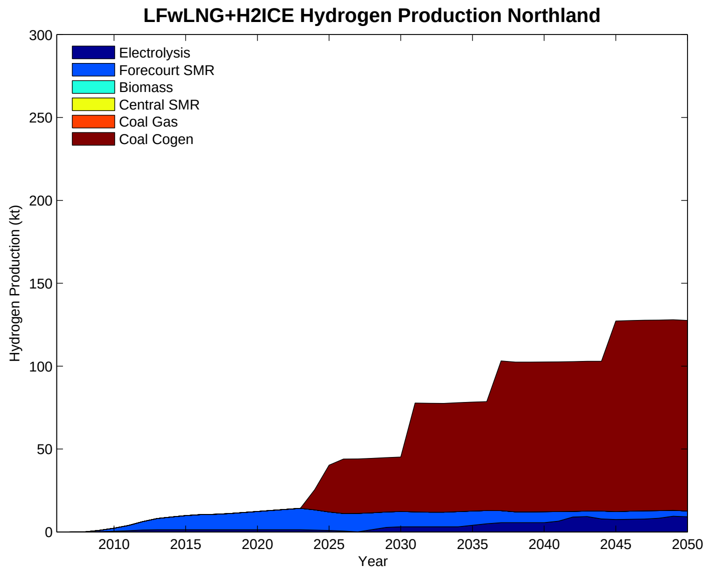







LFwLNG+H2ICE Hydrogen Production Hawke's Bay
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwLNG+H2ICE Hydrogen Production Nelson−Marlborough
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwLNG+H2ICE Hydrogen Production Northland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
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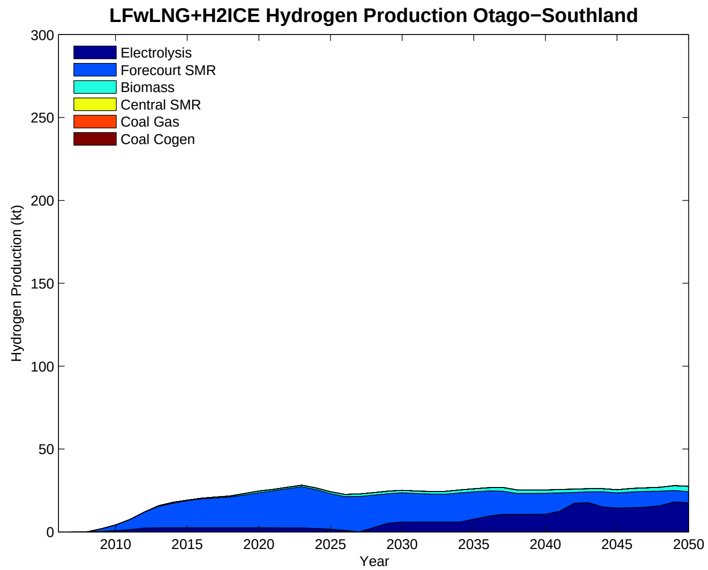
2045
2050


LFwLNG+H2ICE Hydrogen Production Otago−Southland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
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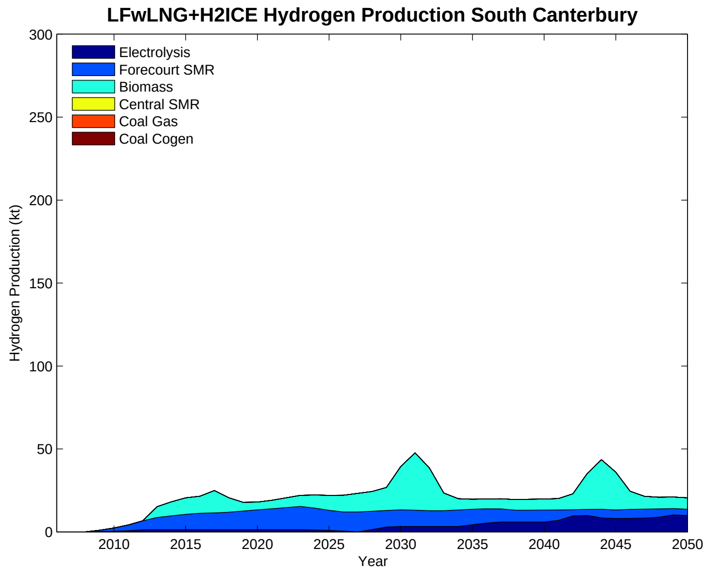
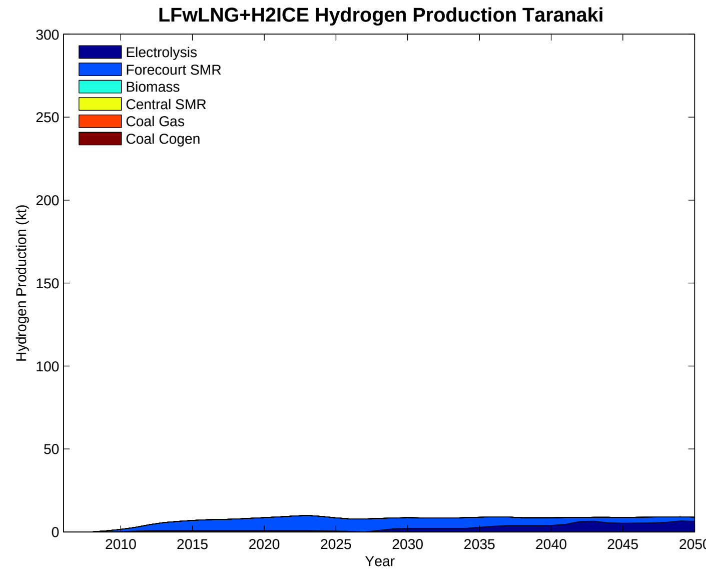
2040
2045
2050


LFwLNG+H2ICE Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


LFwLNG+H2ICE Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
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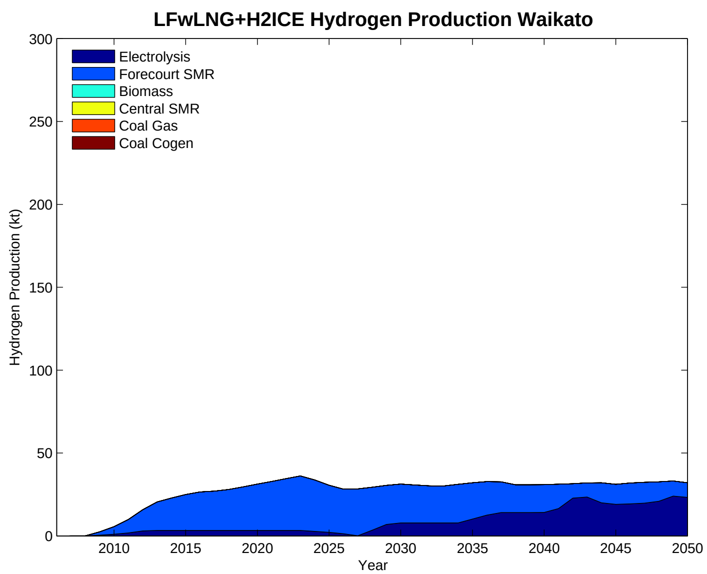
2050


LFwLNG+H2ICE Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
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300
2010
2015
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2025
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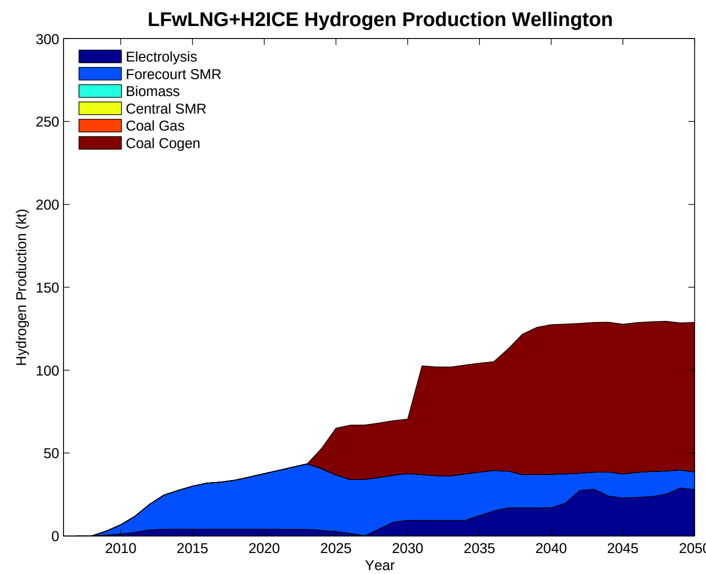
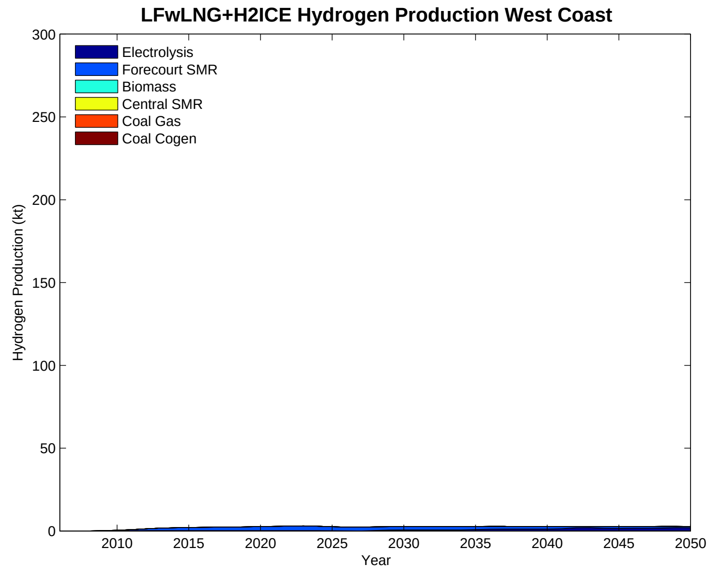
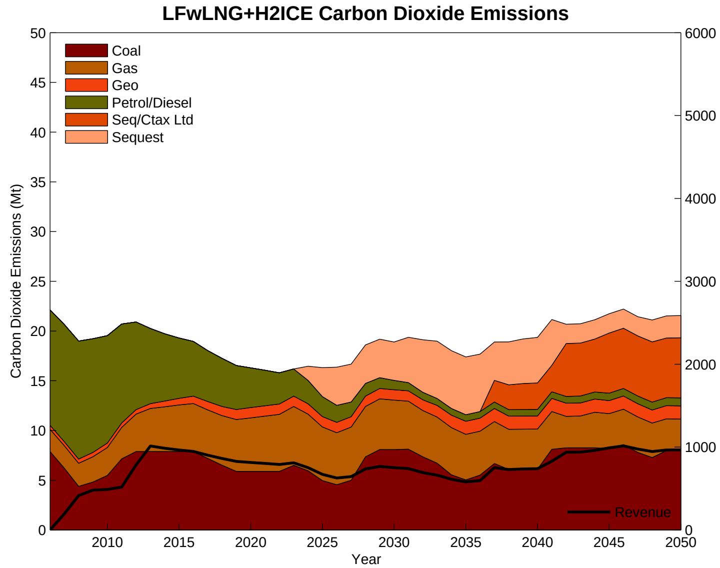
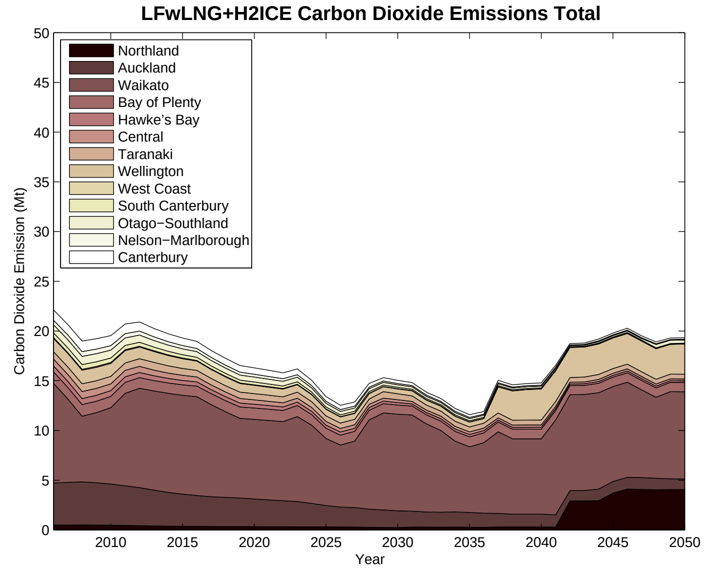
2040
2045
2050

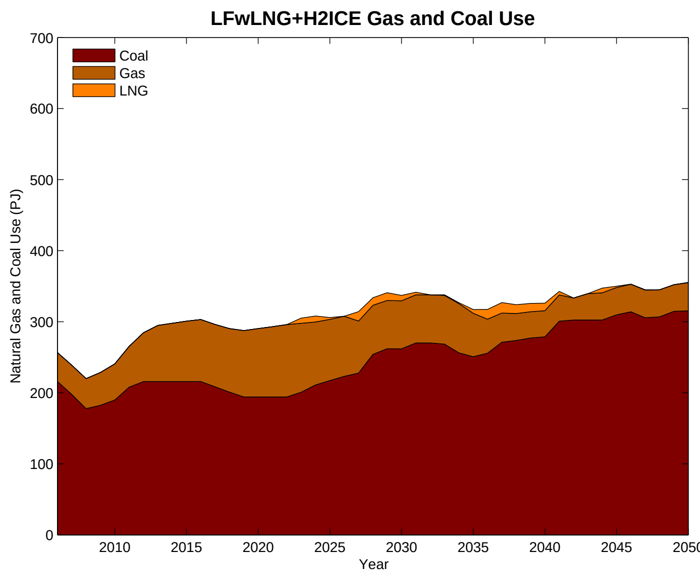

LFwLNG+H2ICE Hydrogen Production Wellington
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

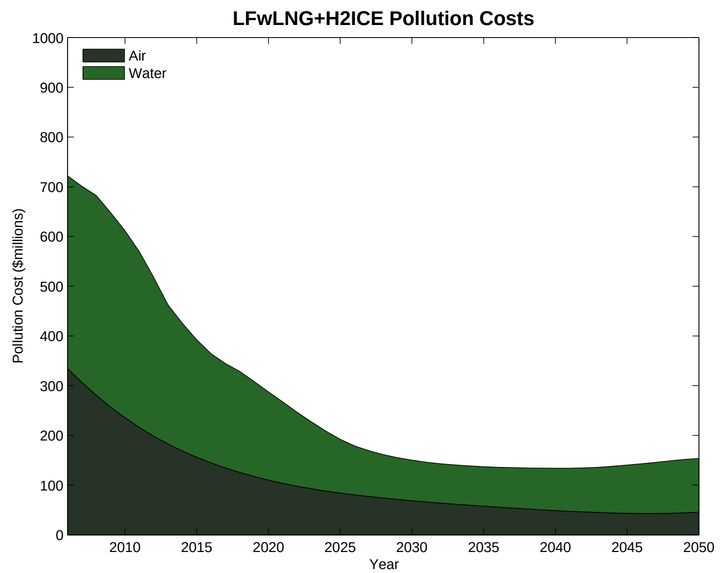

LFwLNG+H2ICE Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
300
250
200
150
100
50
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

Carbon Emissions - Energy Consumption and Pollution

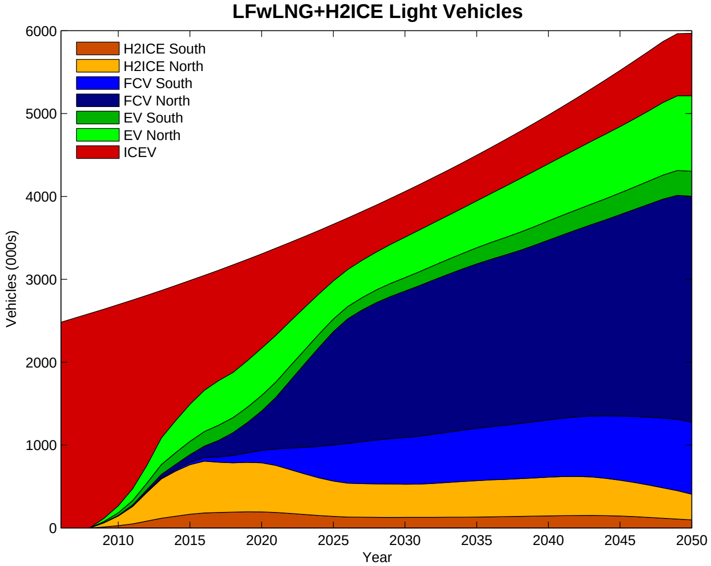


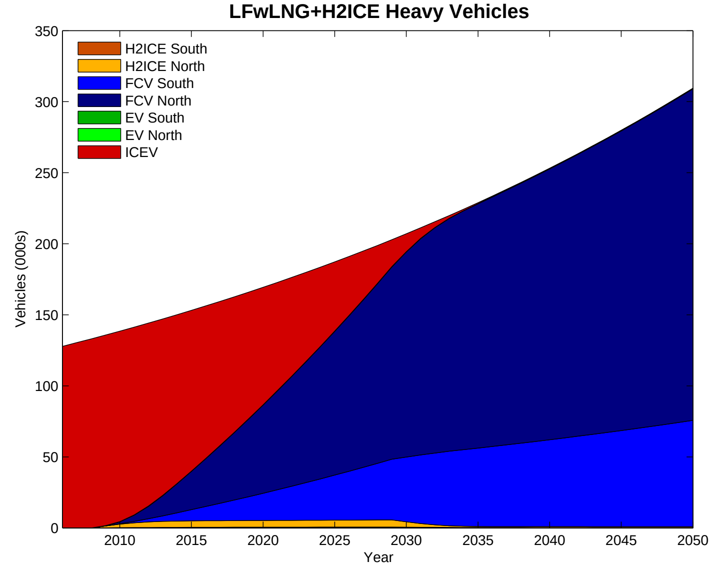


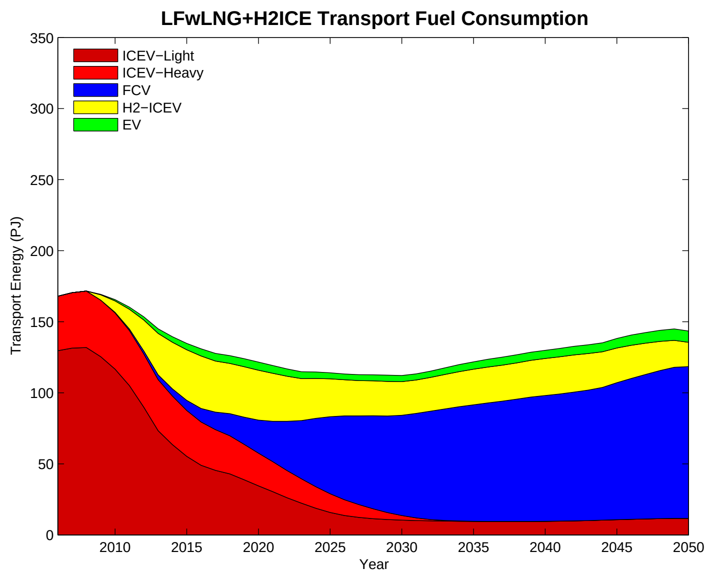




Transportation Sector





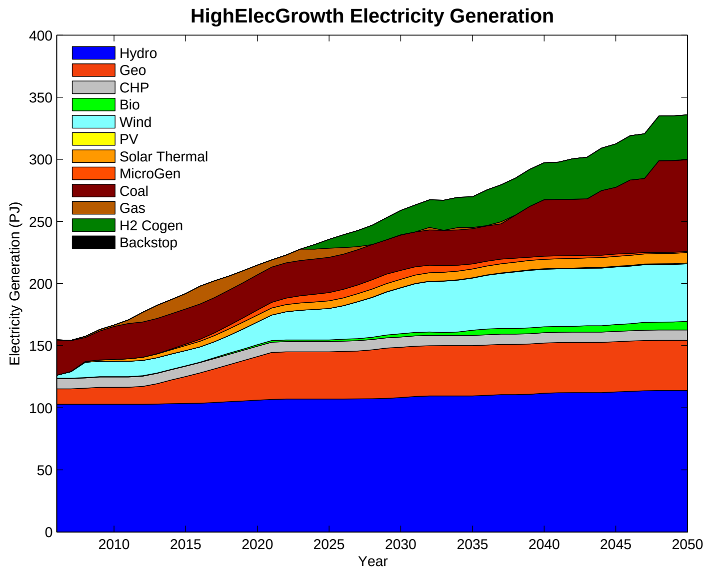


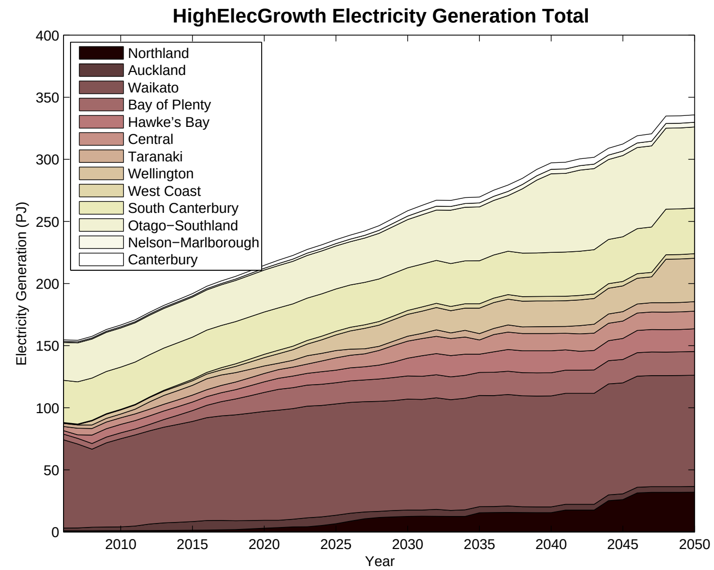
31 Scenario: High Growth in Electricity Demand

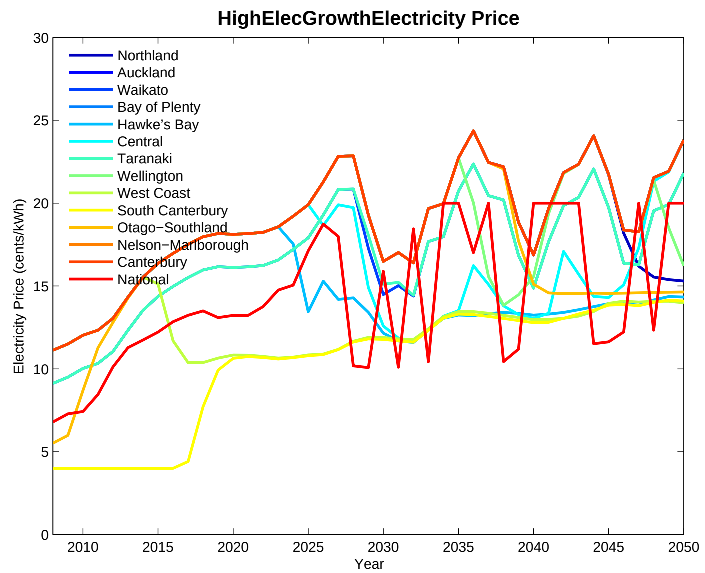
Key results for this scenario are:

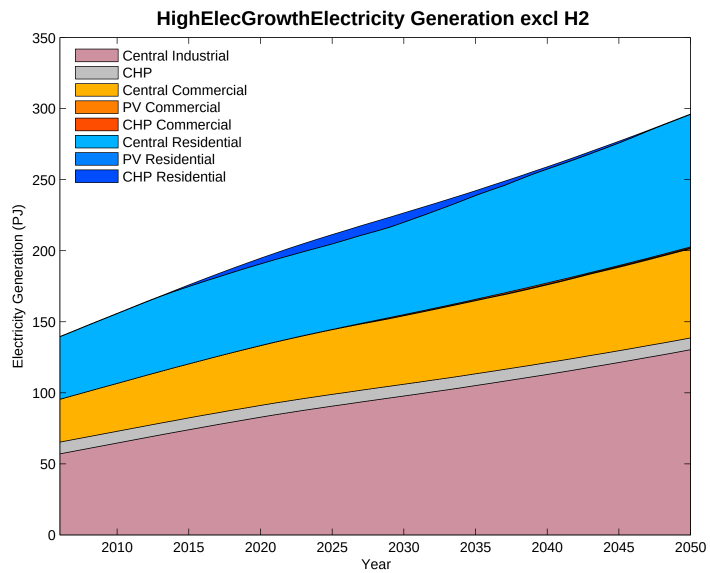
- National wholesale electricity price rises steadily to 18.7 c/kWh in 2026 due the impact of both the carbon tax and the high rate of electricity growth. After 2026 the electricity price cycles between 10 c/kWh and 20 c/kWh driven by high demand in the non-transport sector and the demand of producing hydrogen by electrolysis.
- CO_2 emissions in 2050 are 23% above 2006 levels with 21% of total emissions being sequestered. A further 24% of emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 79% in 2025 and 67% in 2050.
- Hydrogen generation in 2050 consists of 20% electrolysis, 18% forecourt SMR, 7% biomass gasification, and 55% coal cogeneration.
- Primary fossil fuel energy use increases by 99% between 2006 and 2050.
- 65% of the light vehicle fleet switches to HFCVs by 2050 with 21% switching to EVs. EVs and HFCVs begin to enter the market in significant numbers after 2012 and 2020 respectively, when growth is rapid due to the reducing capital cost of fuel cells and increasing oil price.
- The heavy vehicle fleet is entirely HFCVs by 2033.
- Air and water pollution costs reduce from $722 million in 2006 to $154 million in 2050 .

The National Electricity Market

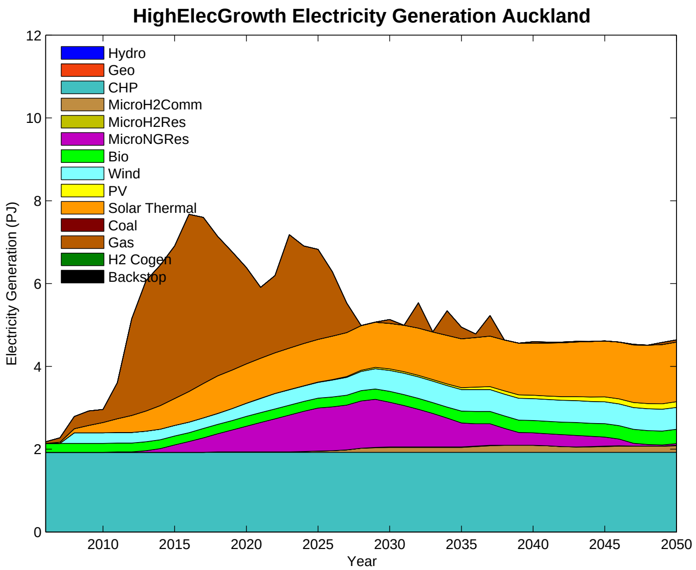


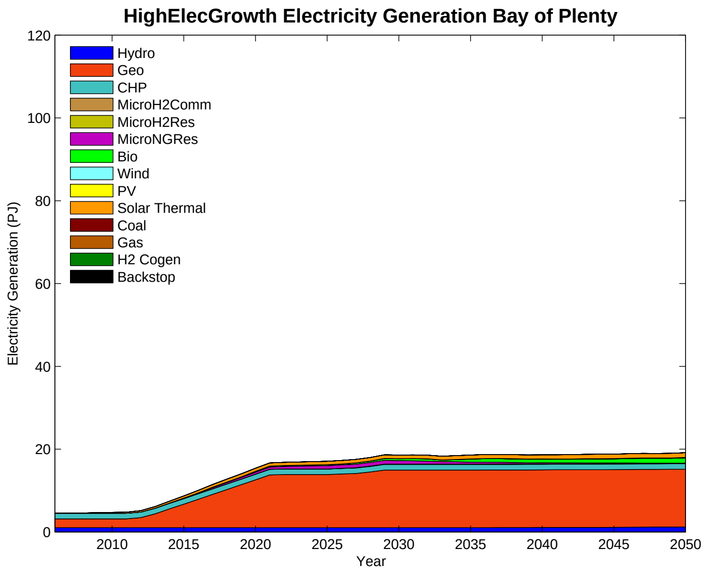


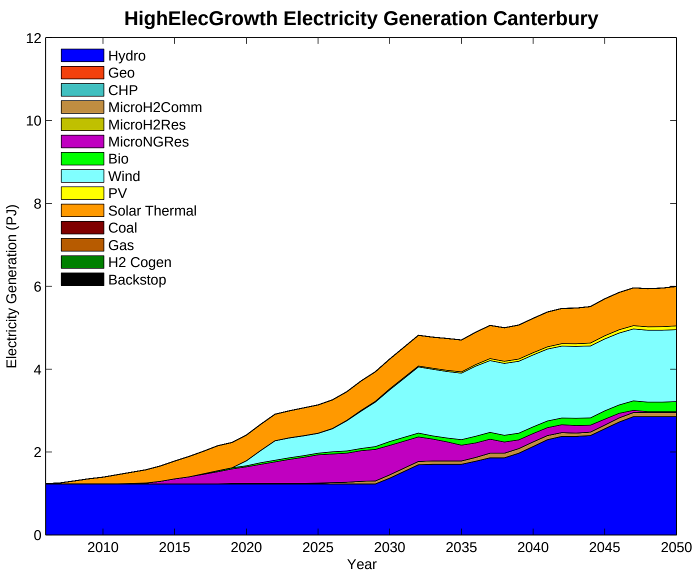


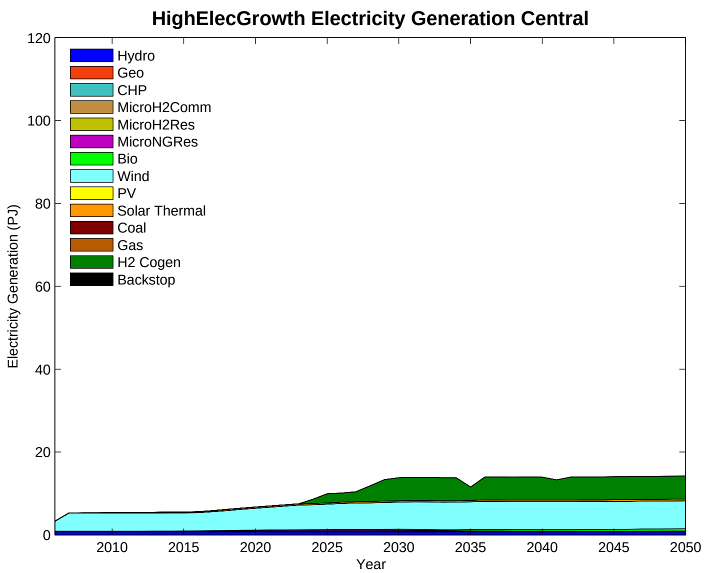


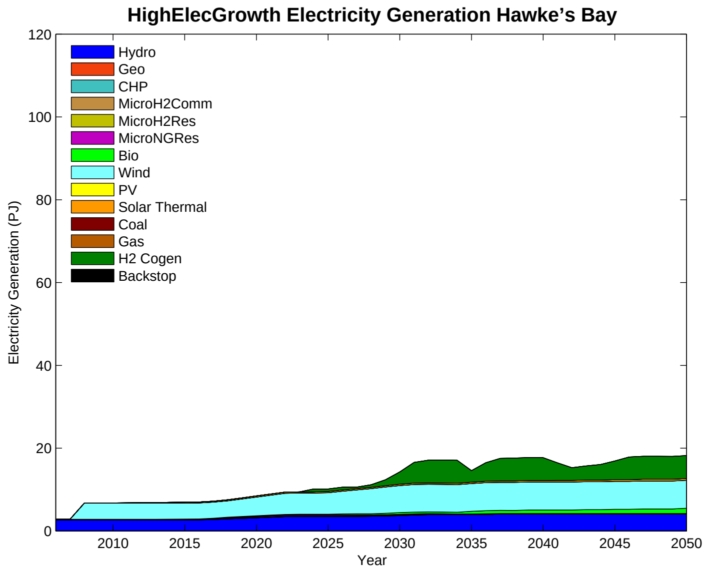
Regional Electricity Markets

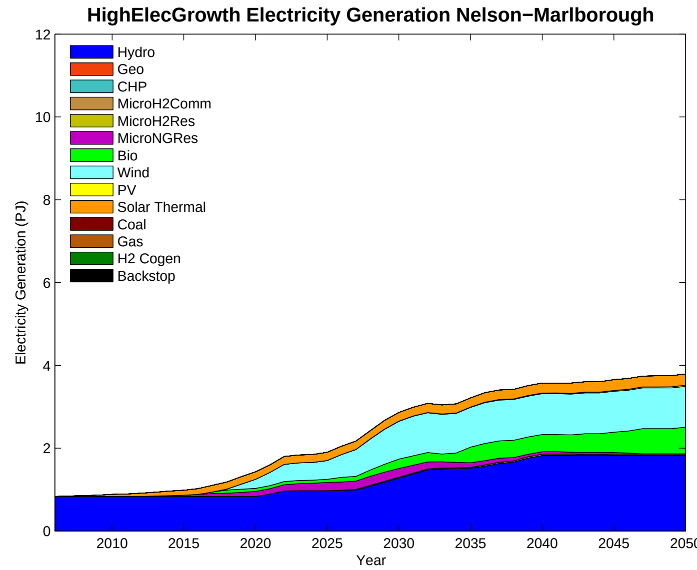


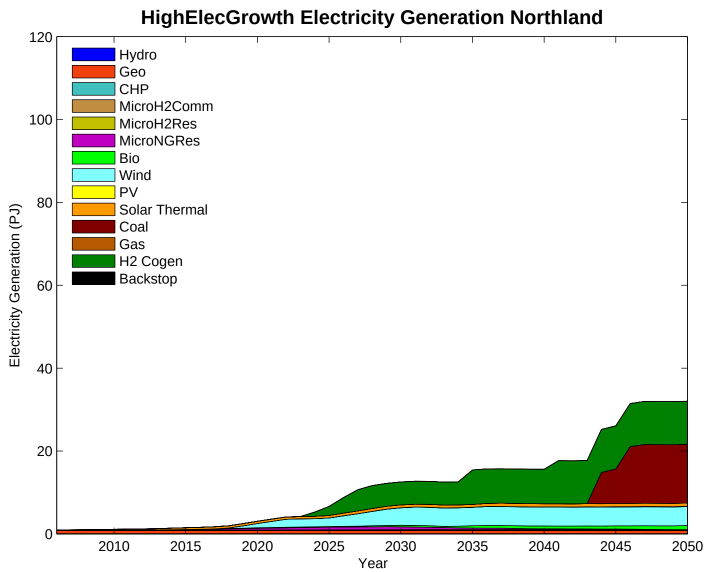


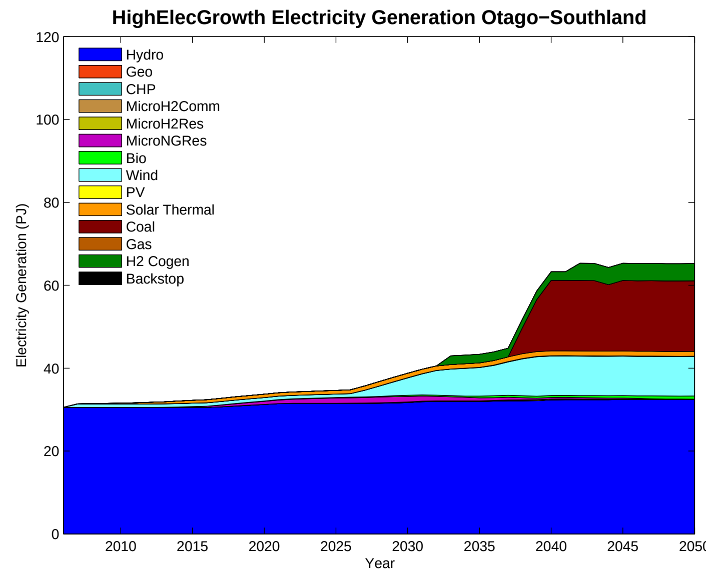




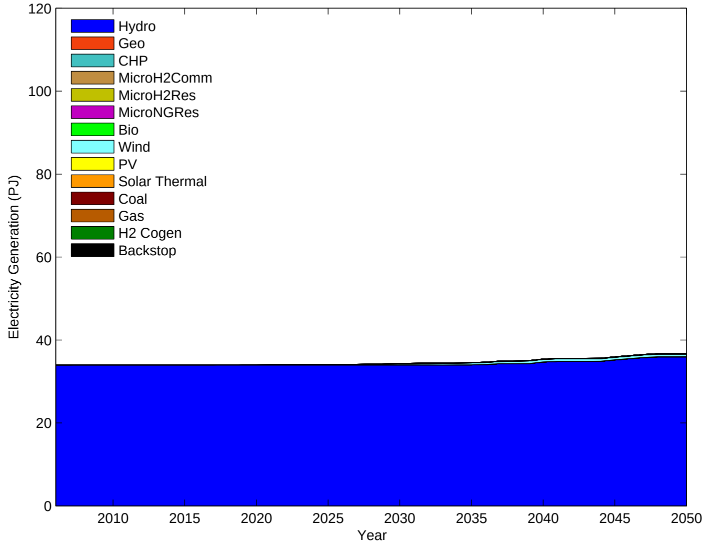

HighElecGrowth Electricity Generation Hawke's Bay
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


HighElecGrowth Electricity Generation Nelson−Marlborough
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

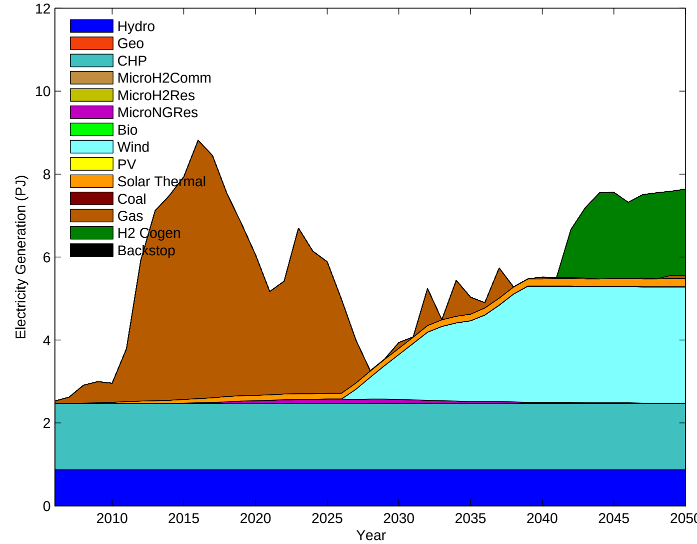

HighElecGrowth Electricity Generation Northland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


HighElecGrowth Electricity Generation Otago−Southland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

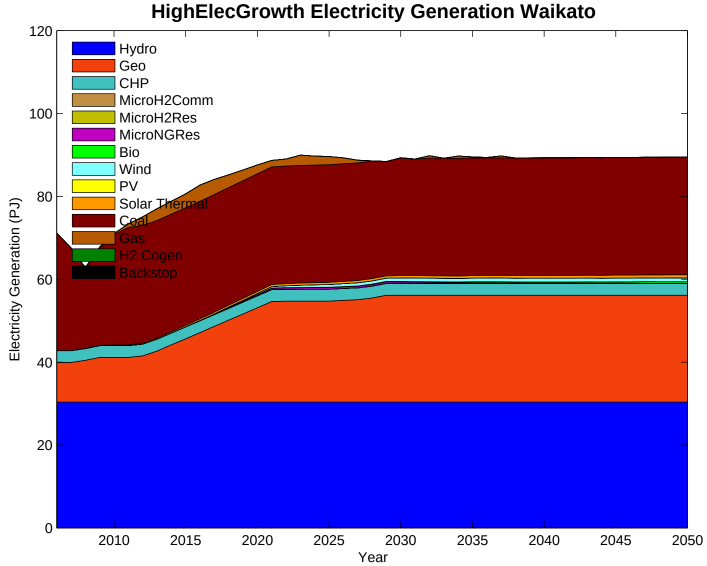
HighElecGrowth Electricity Generation South Canterbury



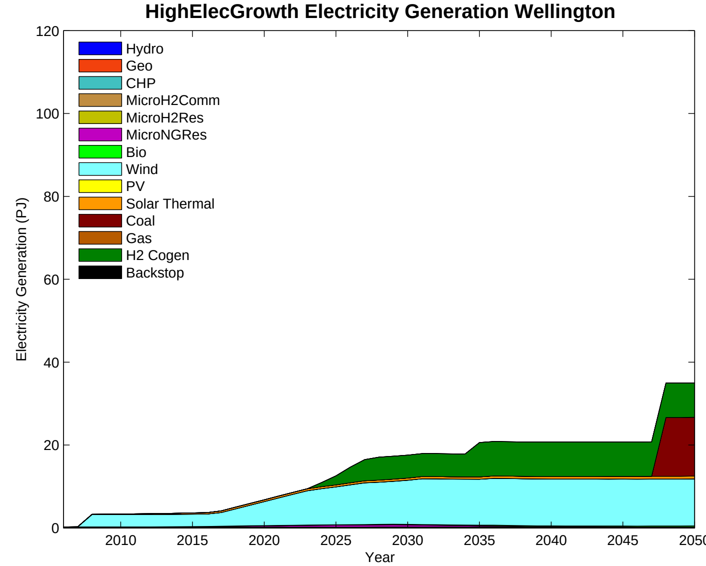
HighElecGrowth Electricity Generation Taranaki

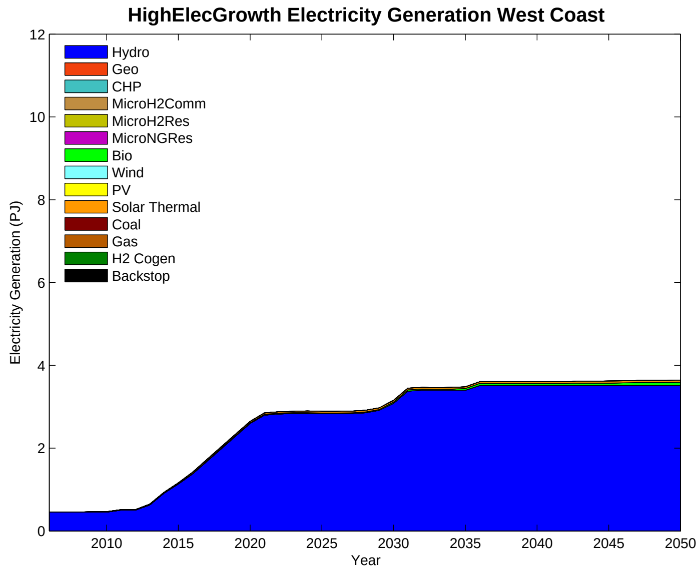


HighElecGrowth Electricity Generation Waikato

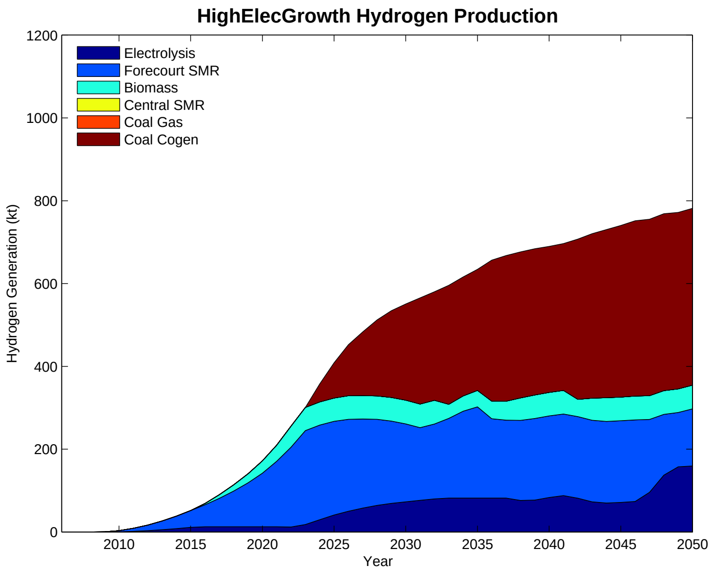


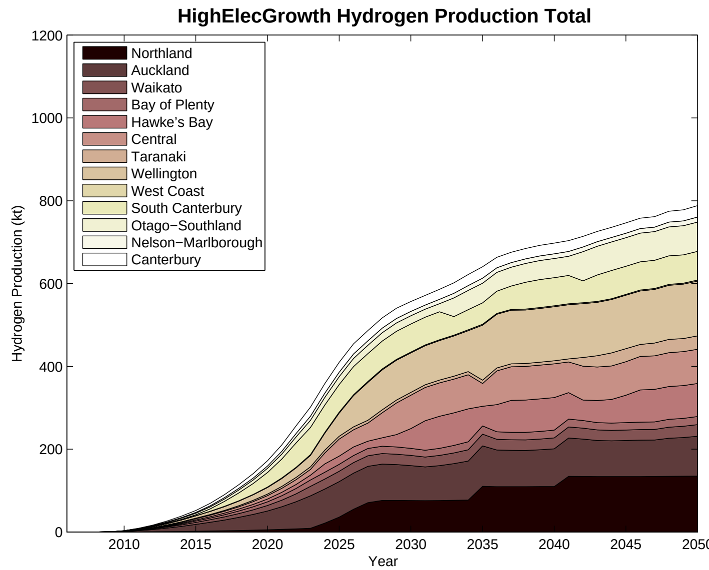
HighElecGrowth Electricity Generation Wellington

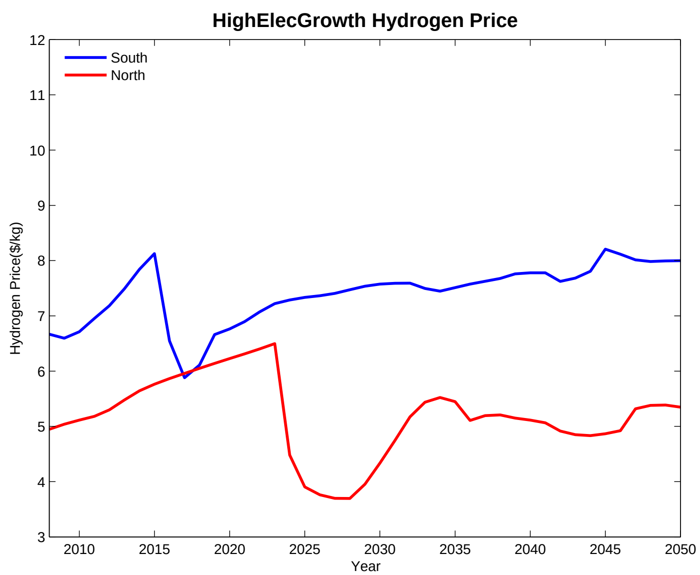



HighElecGrowth Electricity Generation West Coast
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050

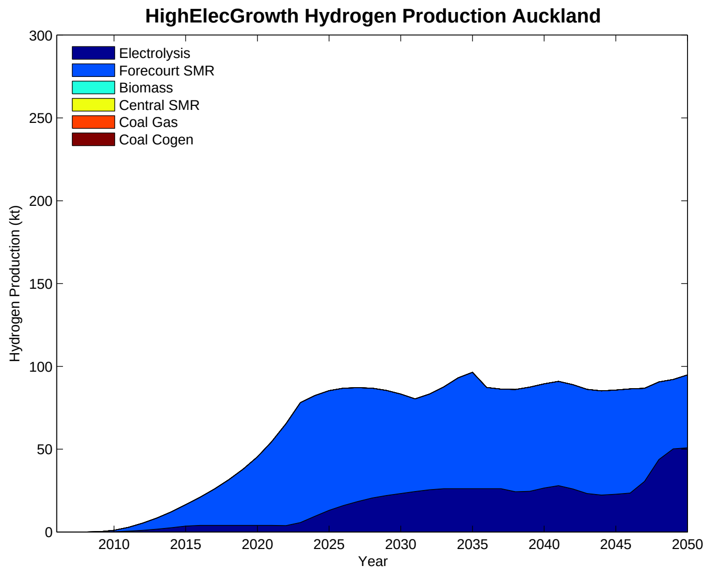
The National Hydrogen Market

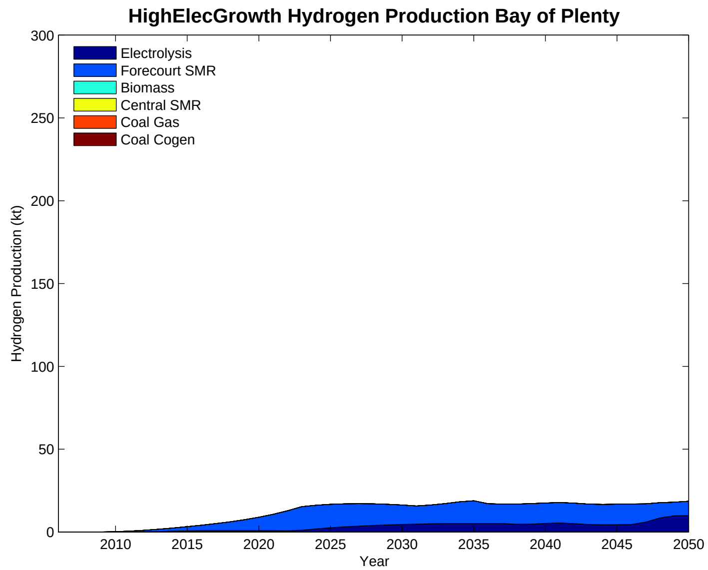


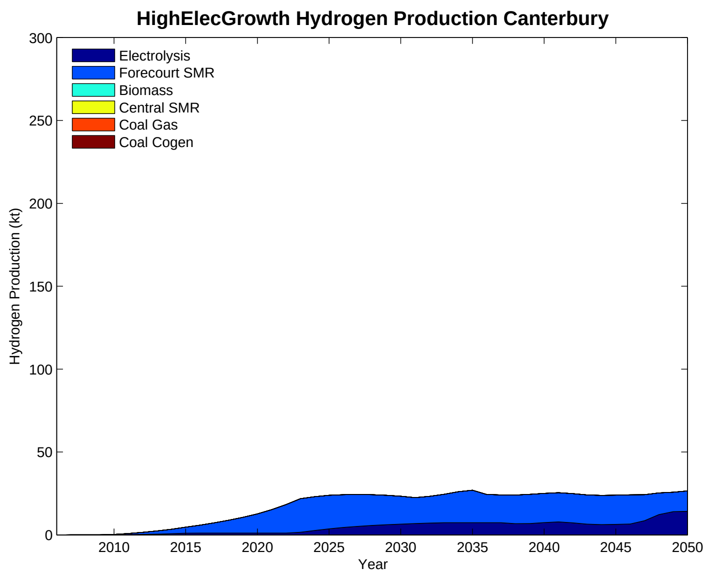


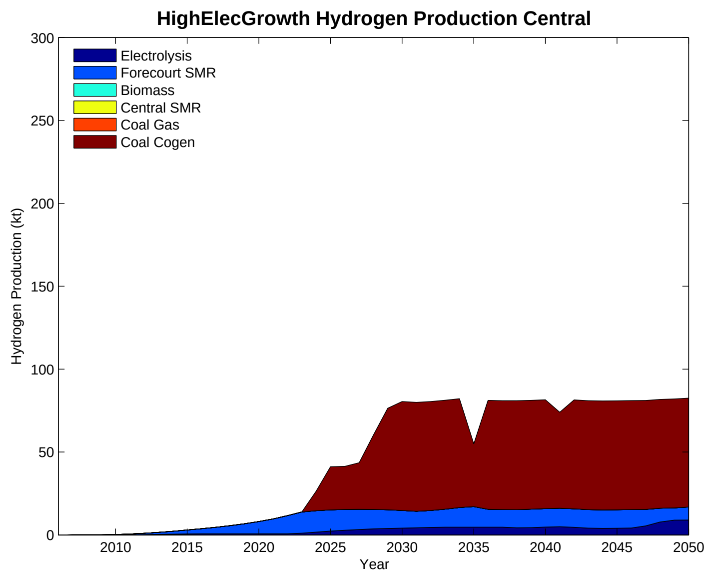


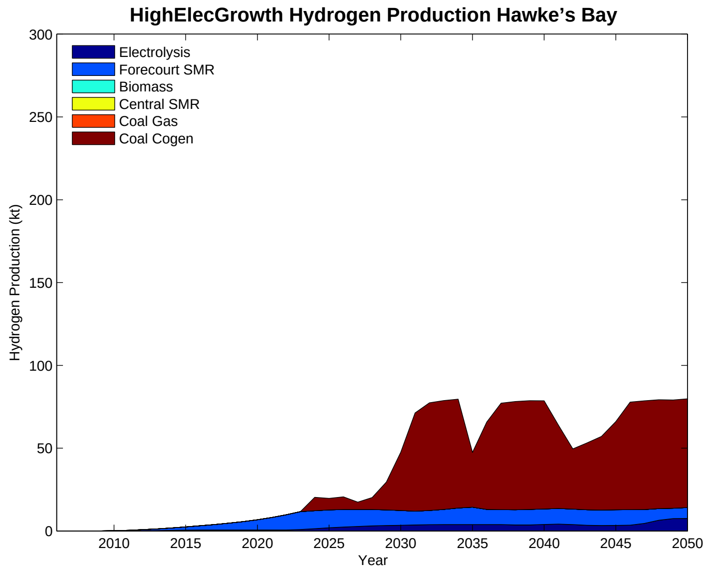
Regional Hydrogen Markets

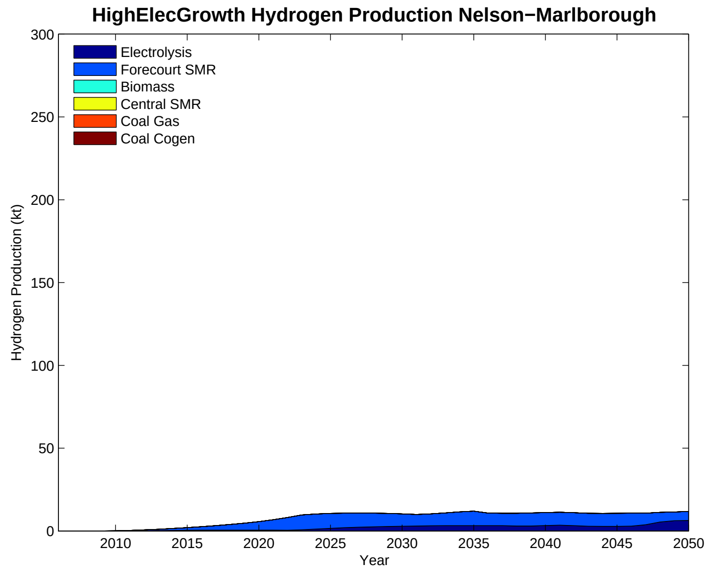


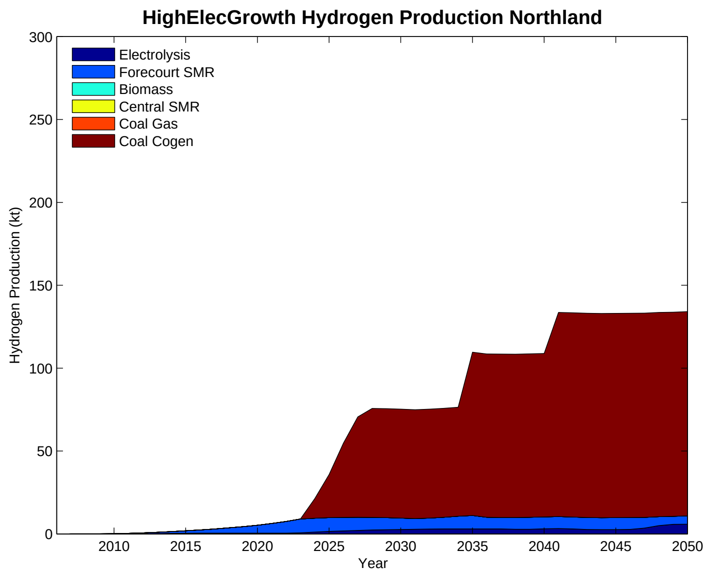


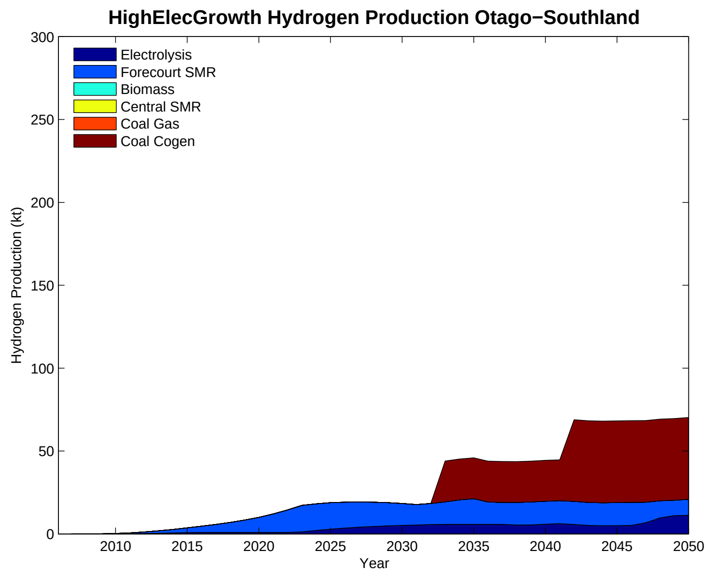


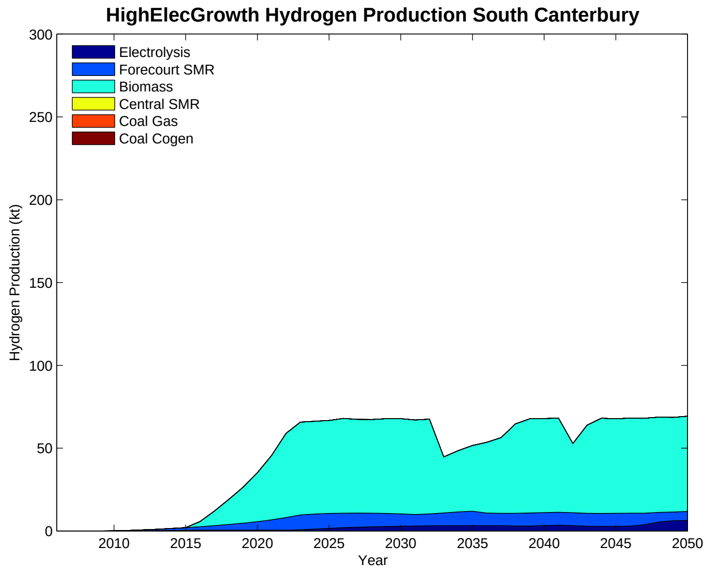


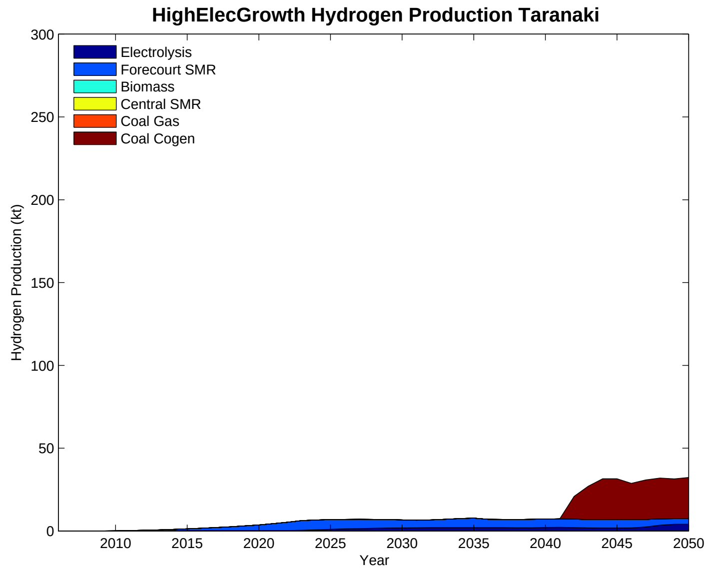

HighElecGrowth Hydrogen Production Hawke's Bay
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

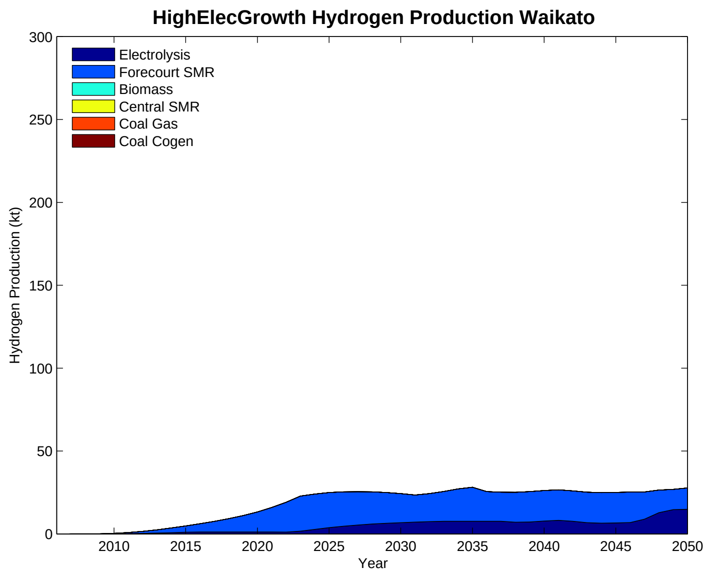

HighElecGrowth Hydrogen Production Nelson−Marlborough
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

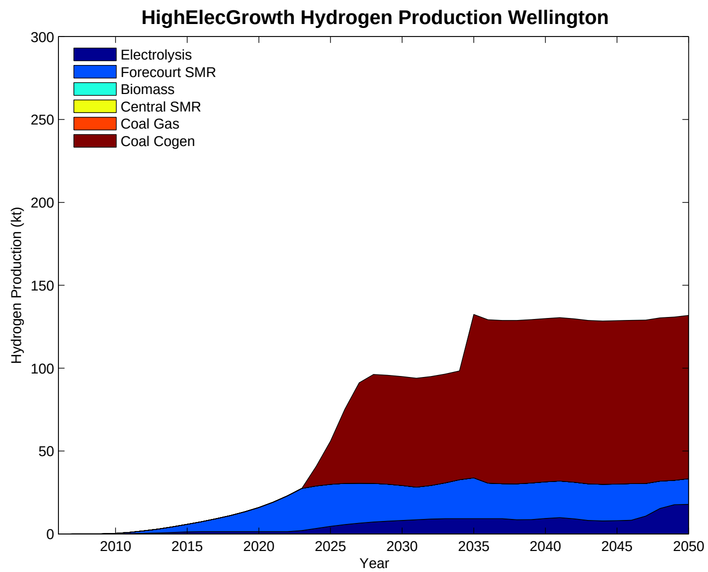

HighElecGrowth Hydrogen Production Northland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

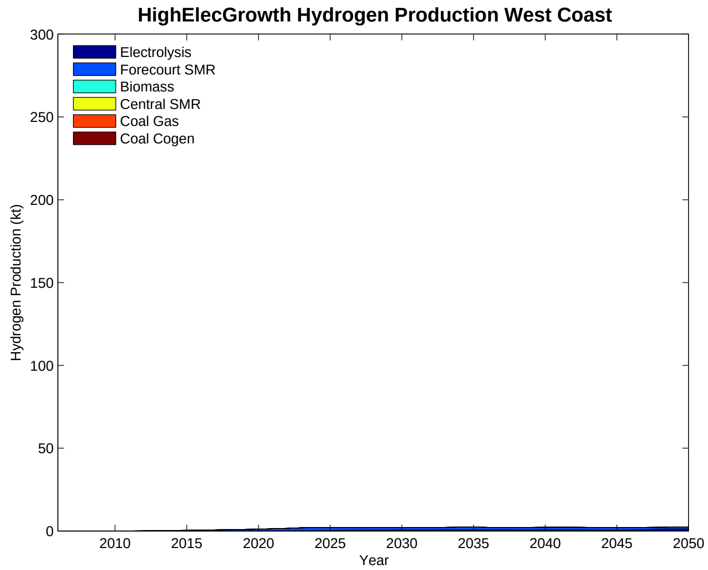

HighElecGrowth Hydrogen Production Otago−Southland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


HighElecGrowth Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

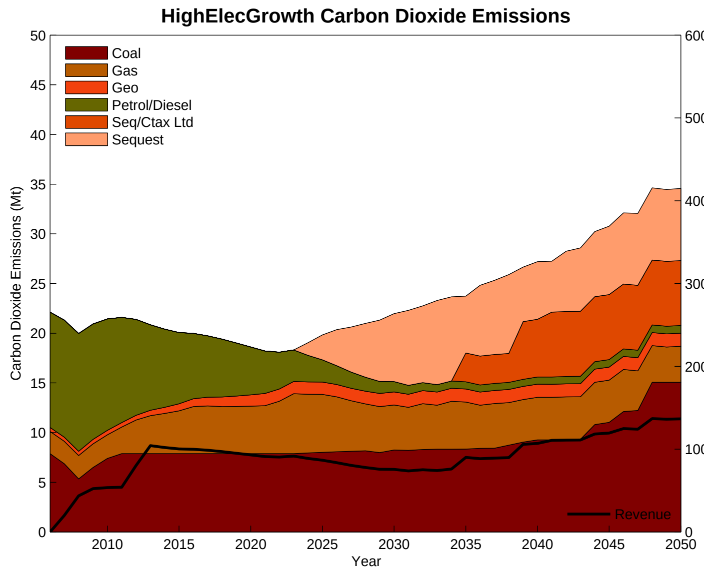

HighElecGrowth Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

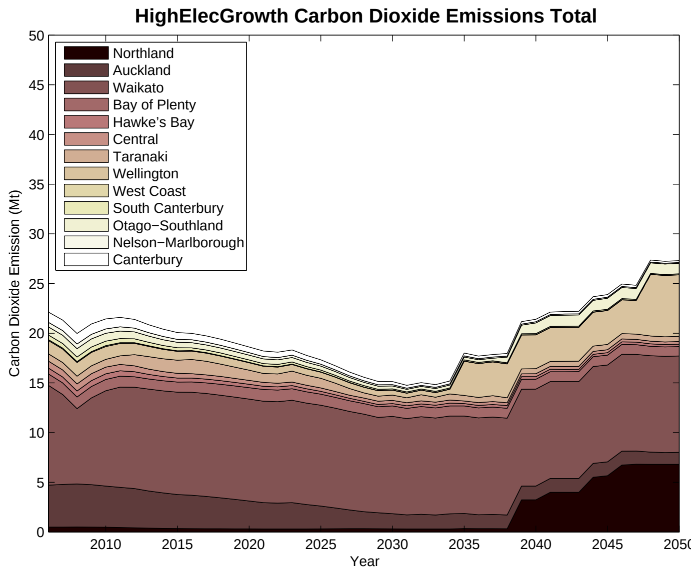

HighElecGrowth Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

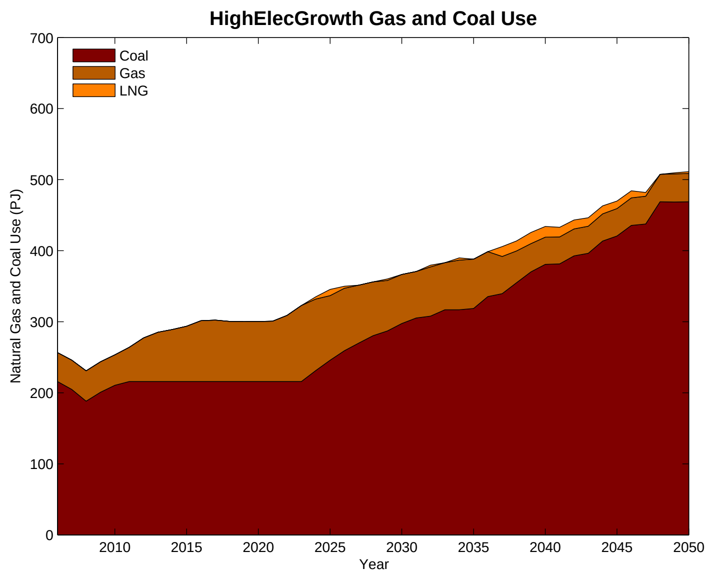

HighElecGrowth Hydrogen Production Wellington
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

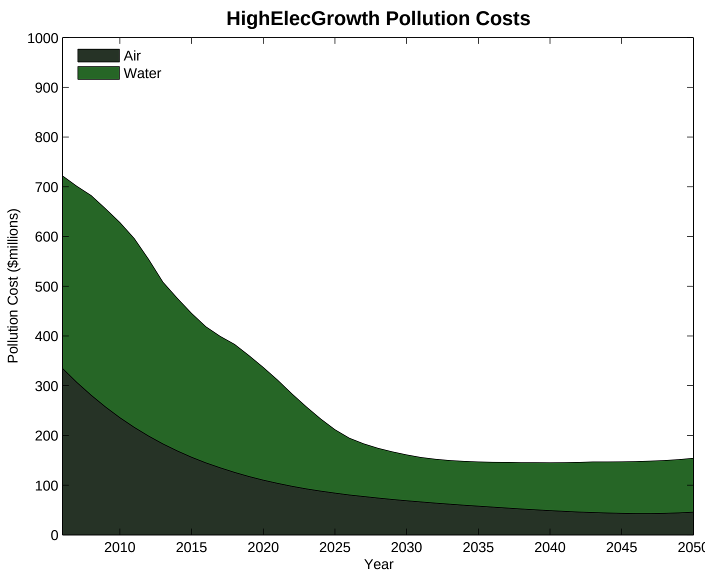

HighElecGrowth Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
300
250
200
150
100
50
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

Carbon Emissions - Energy Consumption and Pollution

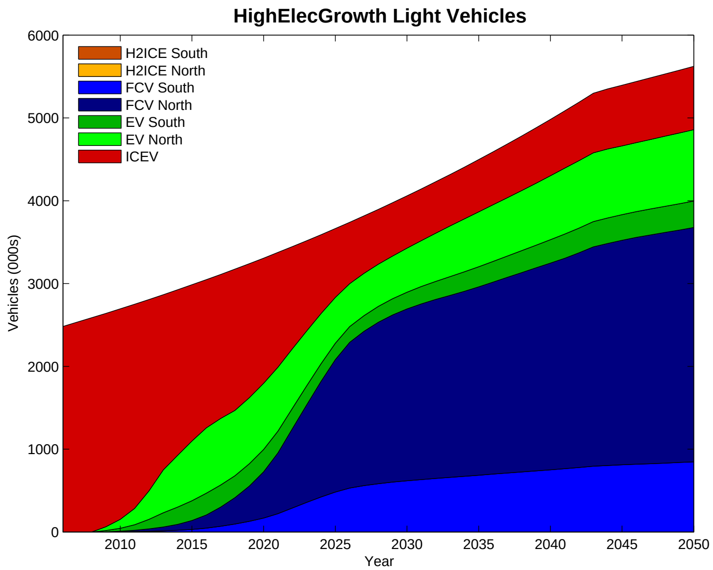


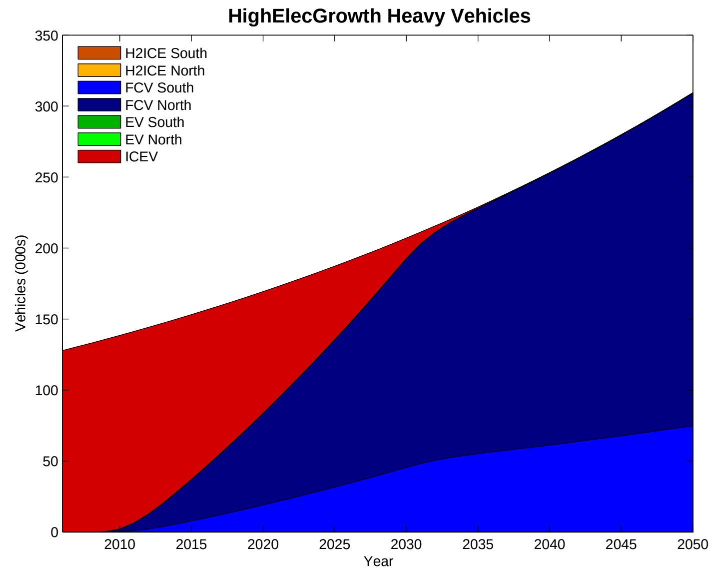


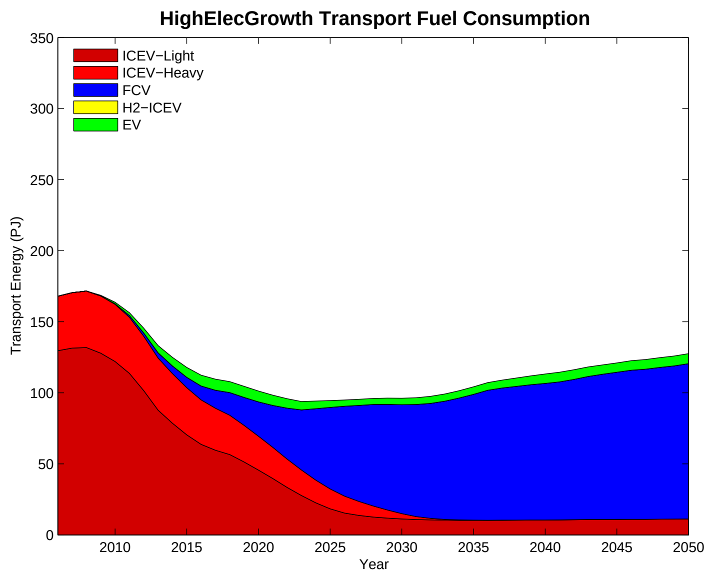




Transportation Sector





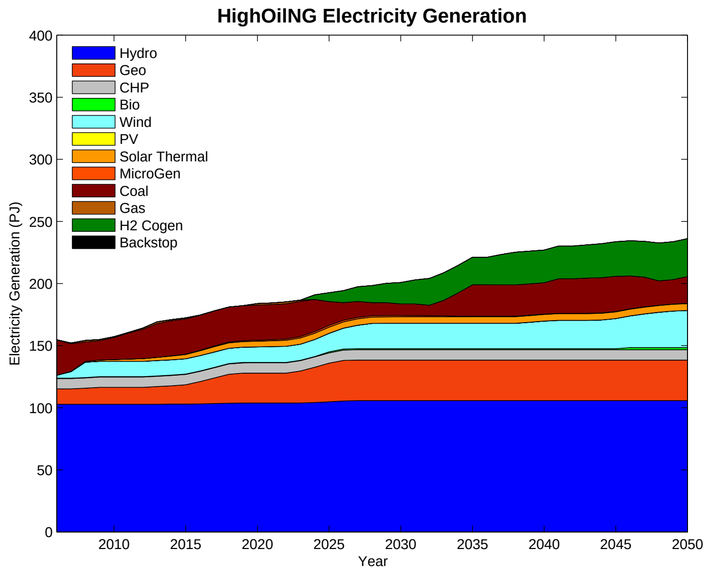


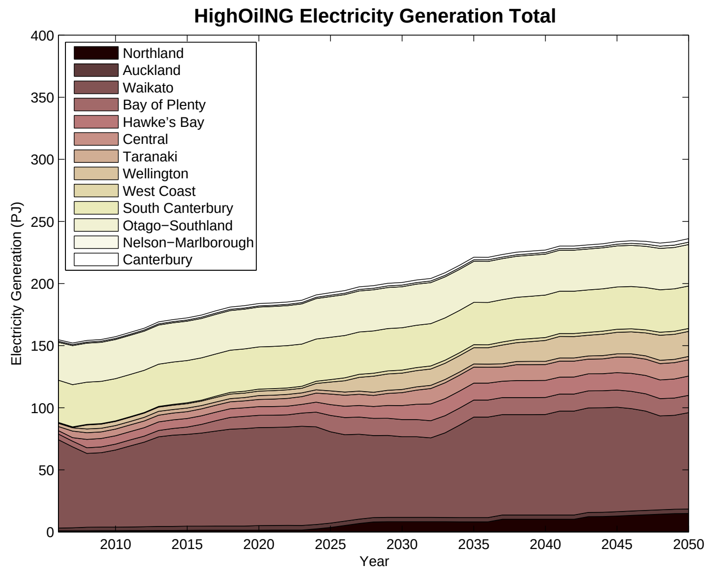
32 Scenario: High Oil Price.

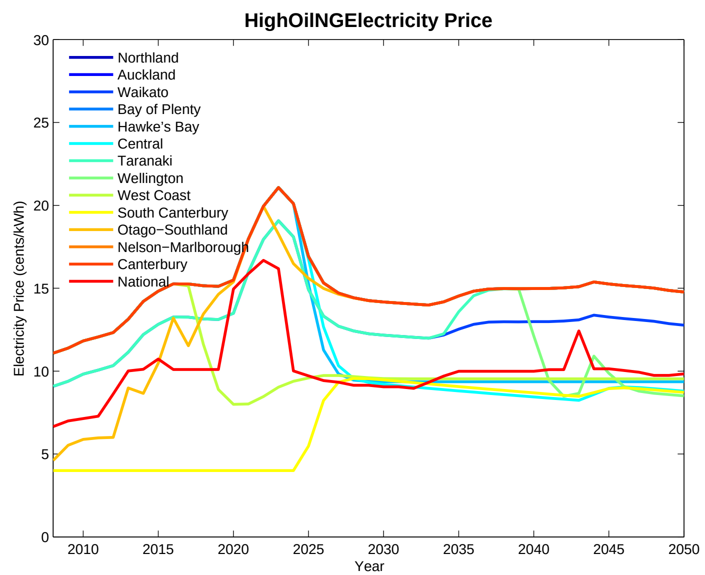
Key results for this scenario in which natural gas prices rise at the same rate as the oil price are:

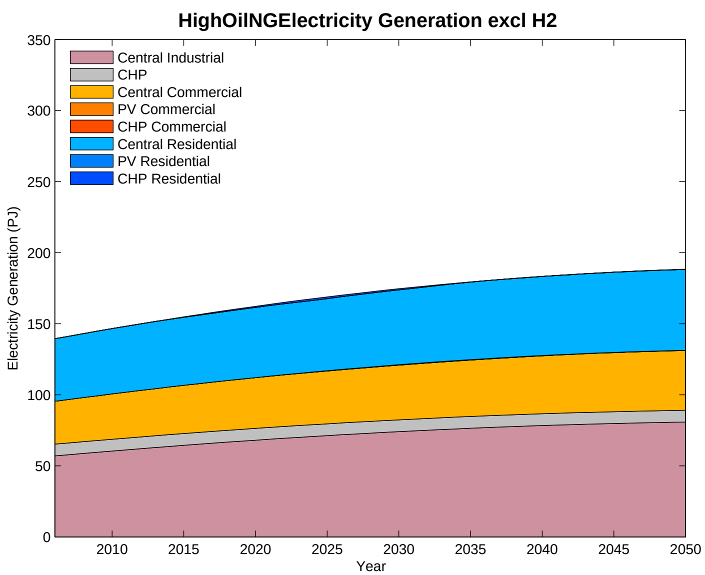
- National wholesale electricity price rises to 10.0 c/kWh in 2013 due the impact of the carbon tax. After 2020 it averages 10.6 c/kWh to 2050 with a peak of 16.6 c/kWh in 2022 due to the electricity demand from the rapidly growing electric vehicle fleet.
- CO_2 emissions in 2050 are 18% below 2006 levels with 18% of total emissions being sequestered. A further 37% of emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 86% in 2025 and 78% in 2050.
- Hydrogen generation in 2050 consists of 12% electrolysis, 11% forecourt SMR, 29% biomass gasification, and 48% coal cogeneration.
- Primary fossil fuel energy use increases by 42% between 2006 and 2050.
- 64% of the light vehicle fleet switches to HFCVs by 2050 with 22% switching to EVs. EVs and HFCVs begin to enter the market in significant numbers after 2012 and 2020 respectively, when growth is rapid due to the reducing capital cost of fuel cells and increasing oil price.
- The heavy vehicle fleet is entirely HFCVs by 2033.
- Air and water pollution costs reduce from $722 million in 2006 to $153 million in 2050.

The National Electricity Market

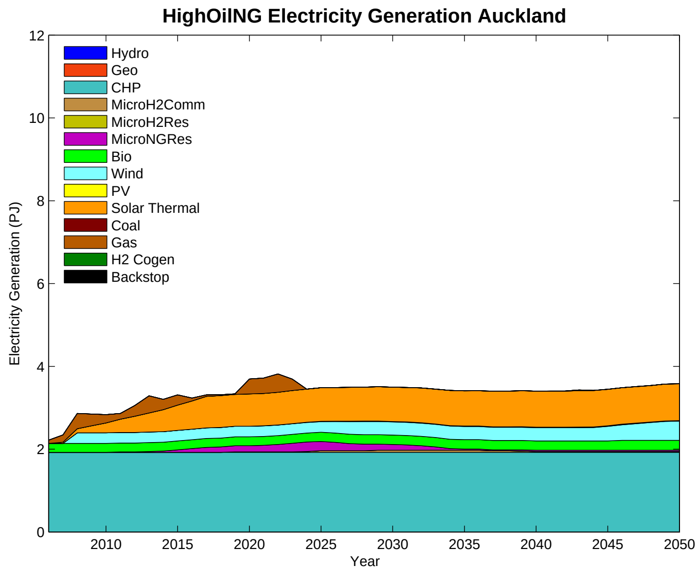


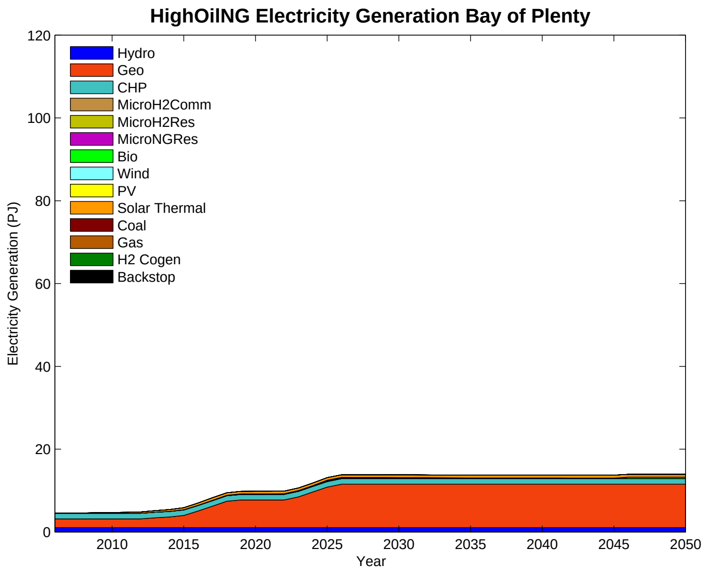


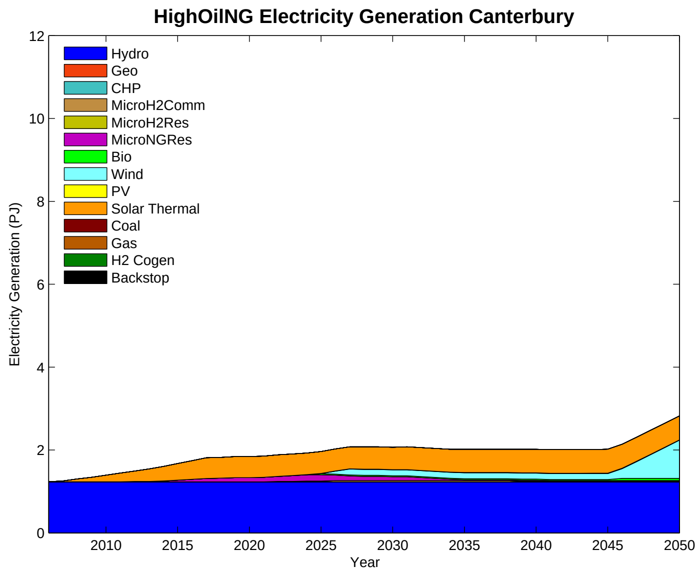


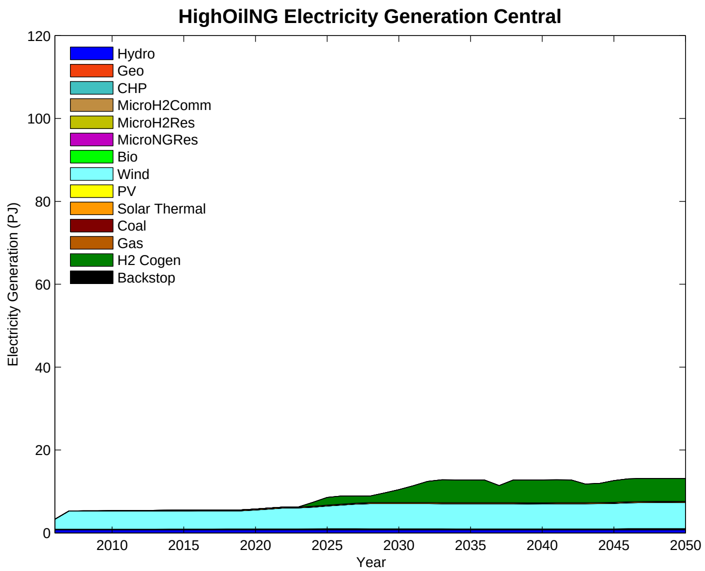


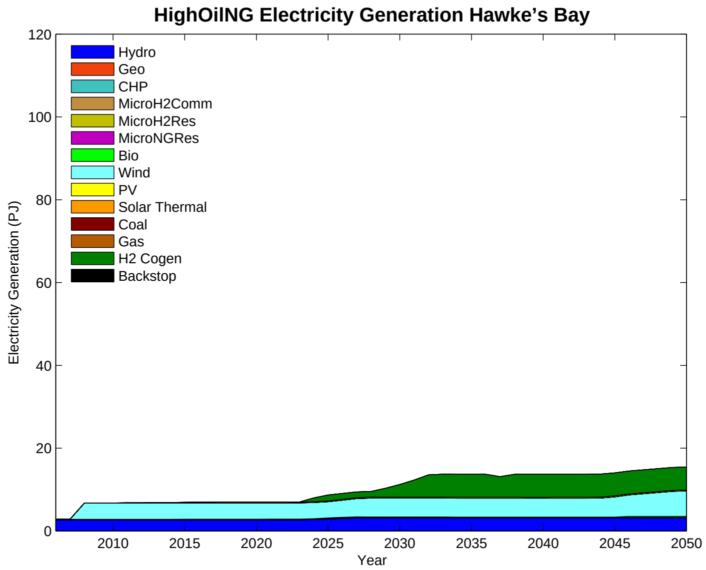
Regional Electricity Markets

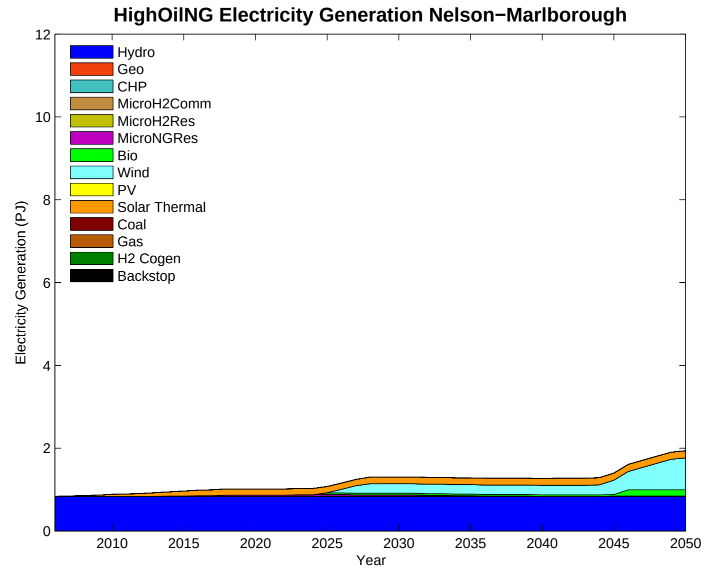


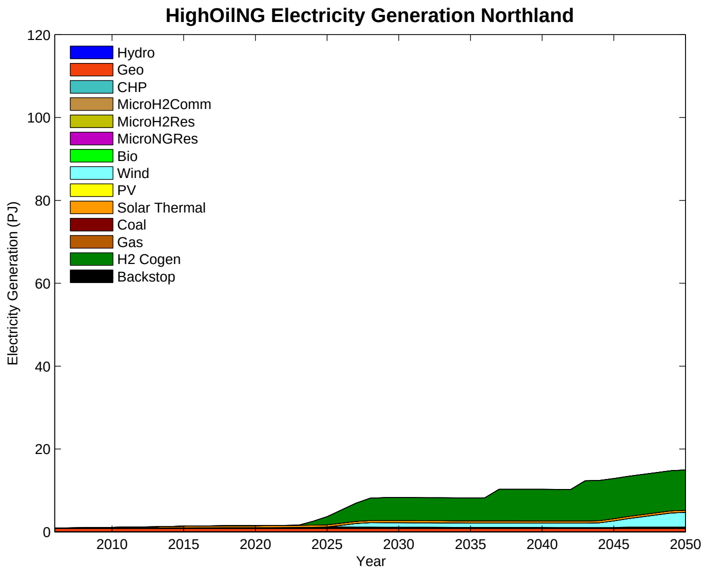


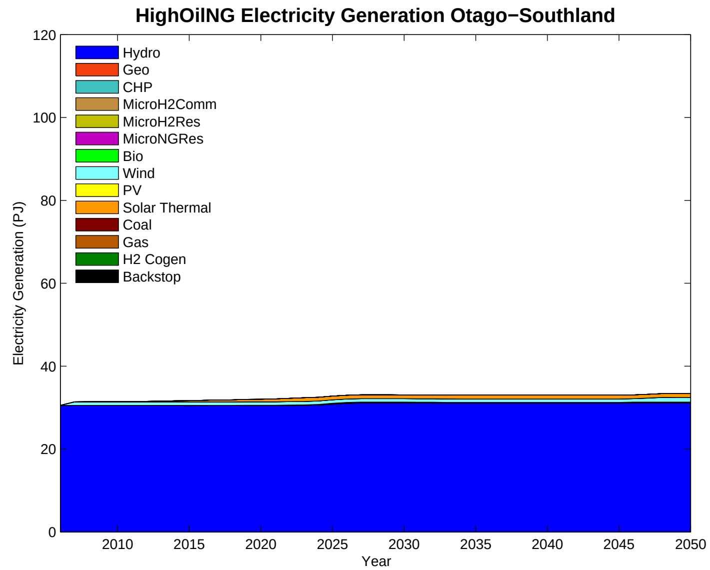


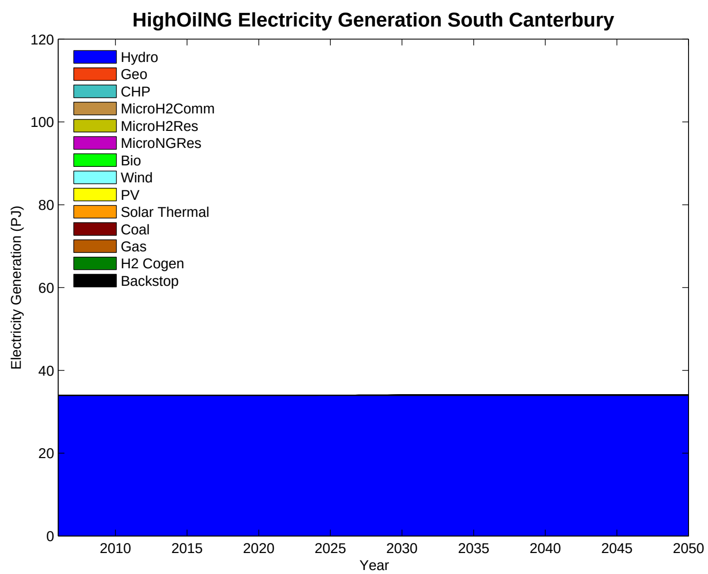


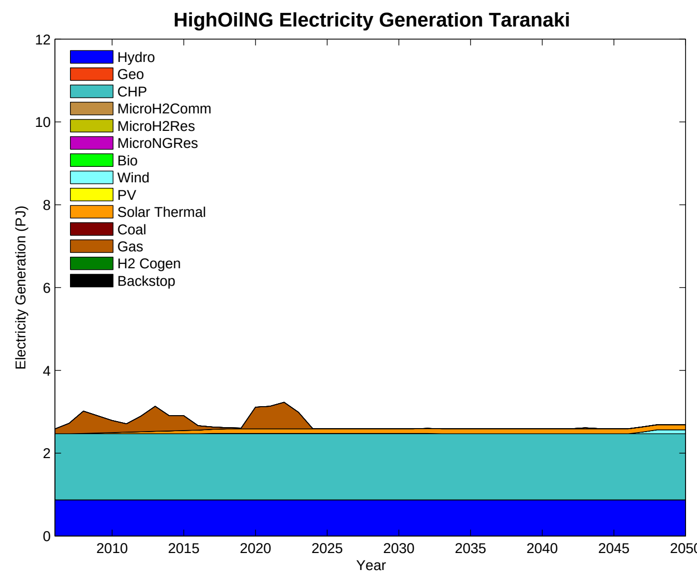

HighOilNG Electricity Generation Hawke's Bay
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

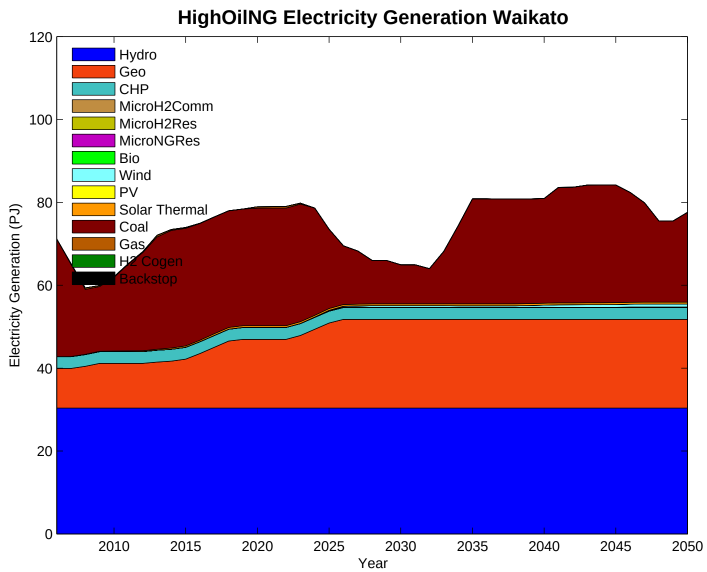

HighOilNG Electricity Generation Nelson−Marlborough
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

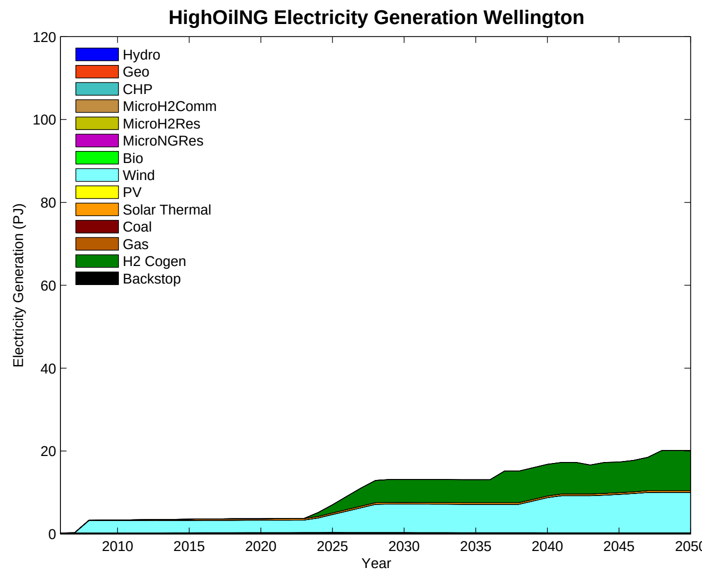

HighOilNG Electricity Generation Northland
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

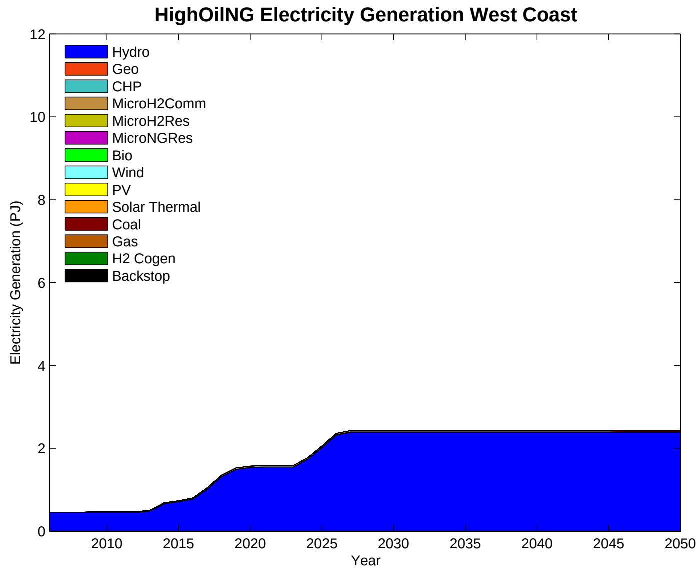

HighOilNG Electricity Generation Otago−Southland
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


HighOilNG Electricity Generation South Canterbury
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

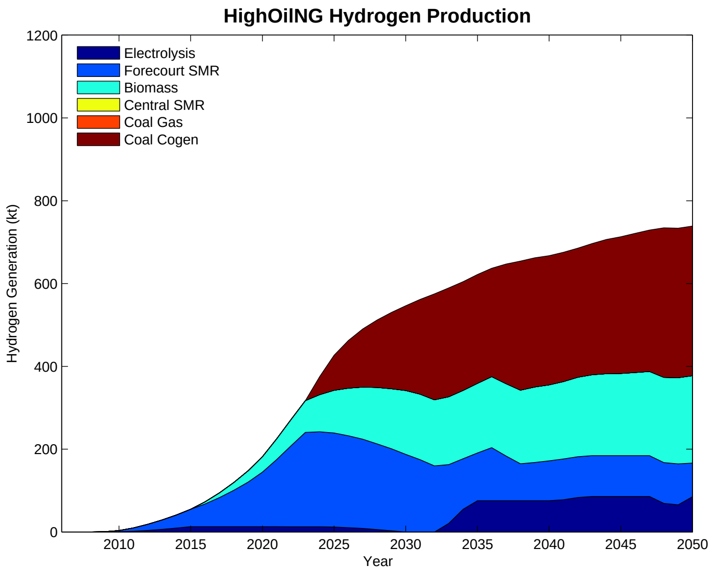

HighOilNG Electricity Generation Taranaki
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

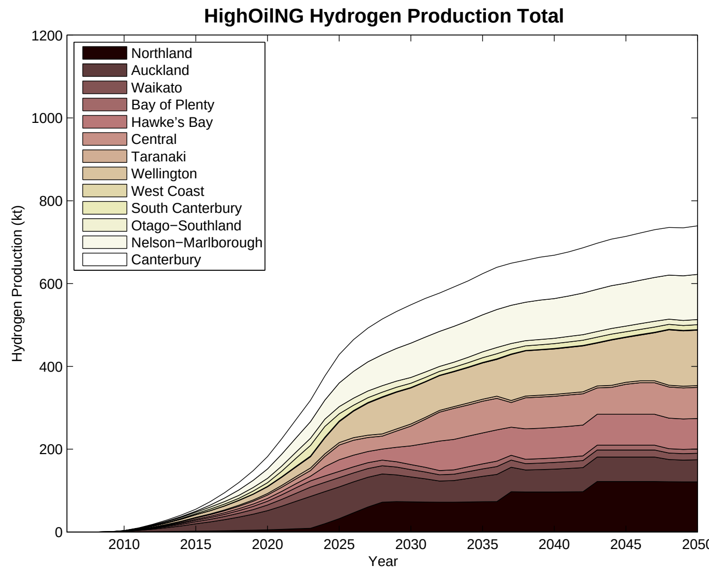

HighOilNG Electricity Generation Waikato
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

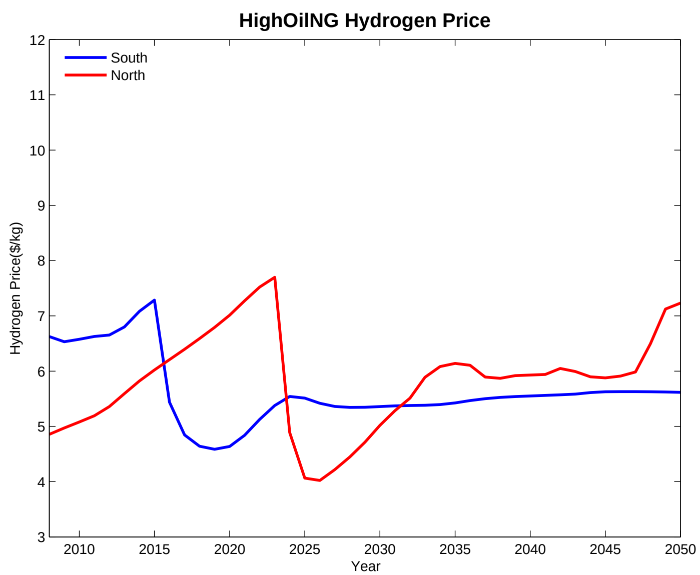

HighOilNG Electricity Generation Wellington
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


HighOilNG Electricity Generation West Coast
Electricity Generation (PJ)
Year
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

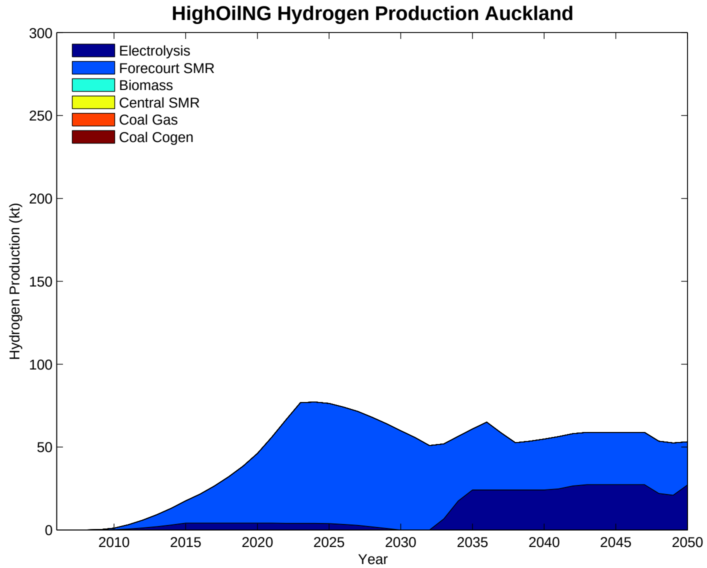
The National Hydrogen Market

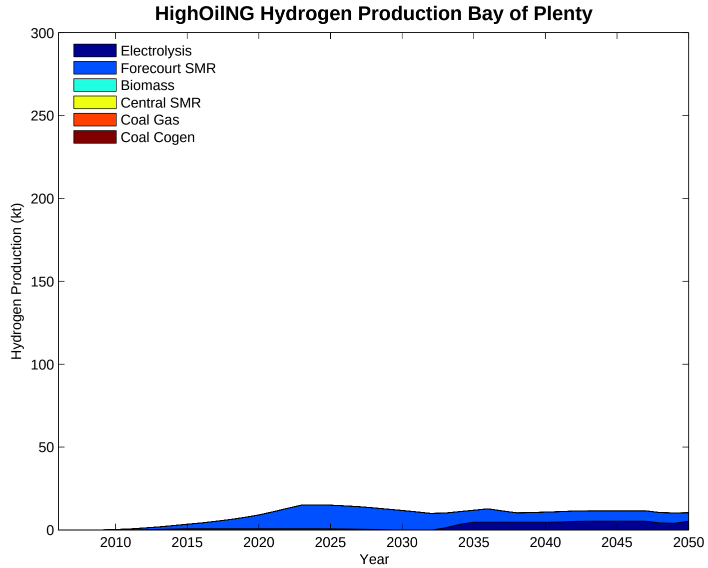


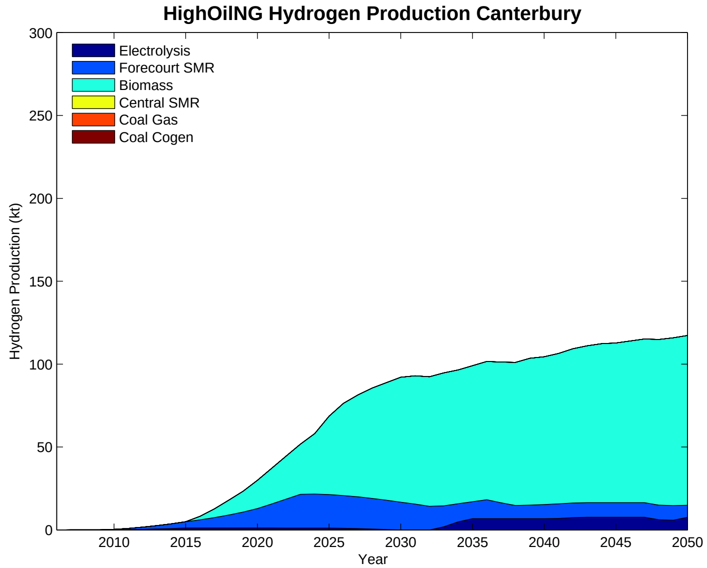


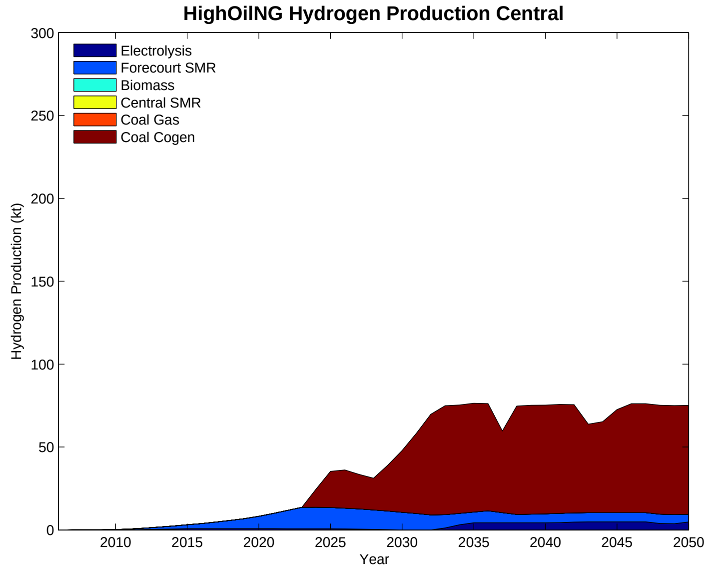


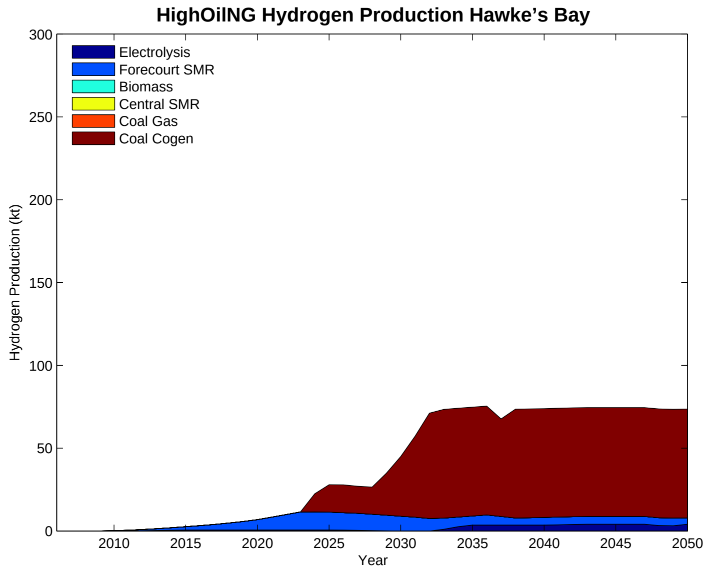
Regional Hydrogen Markets

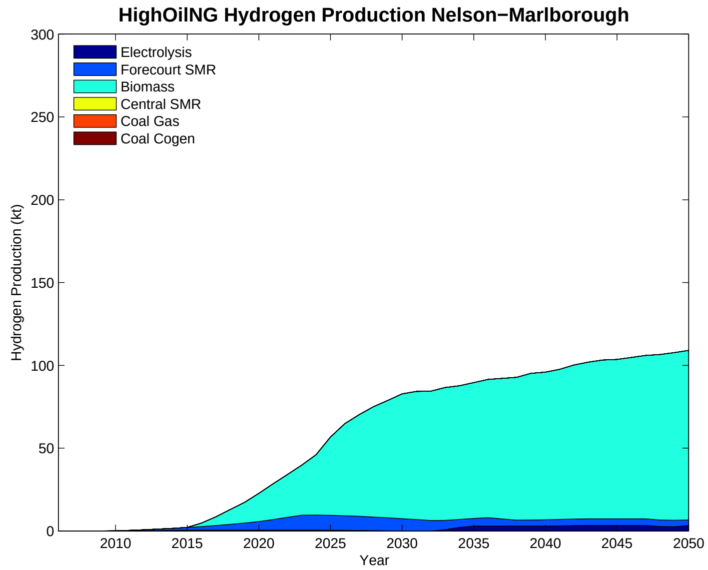


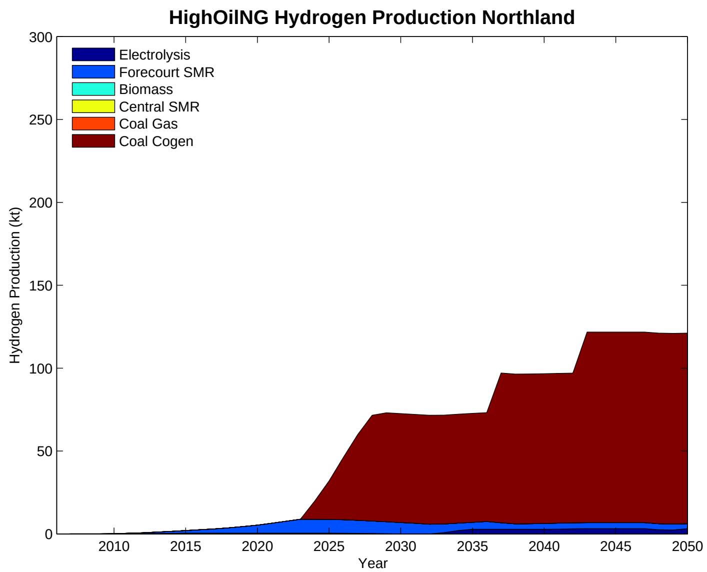


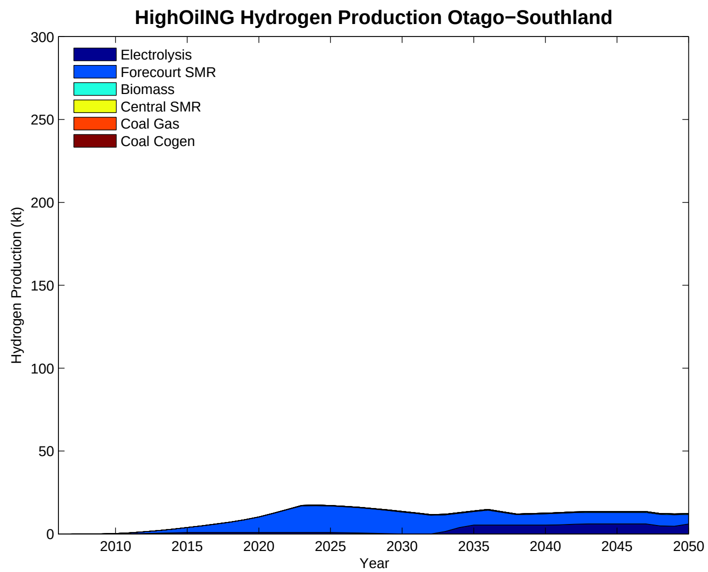


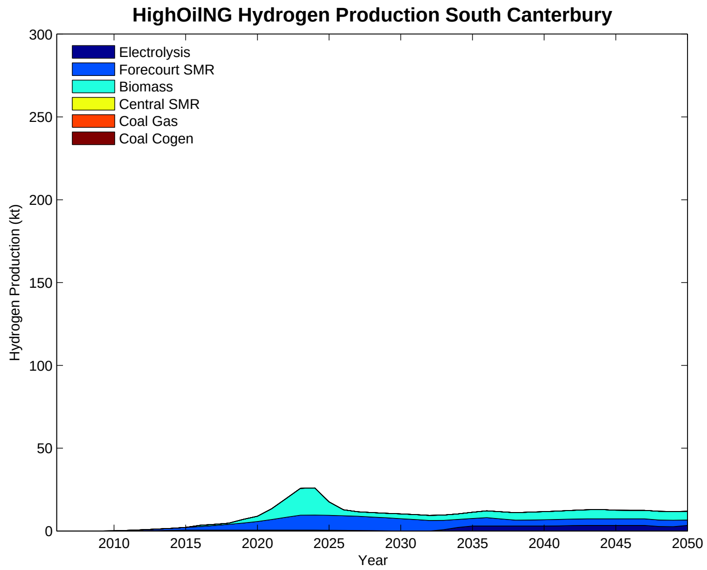


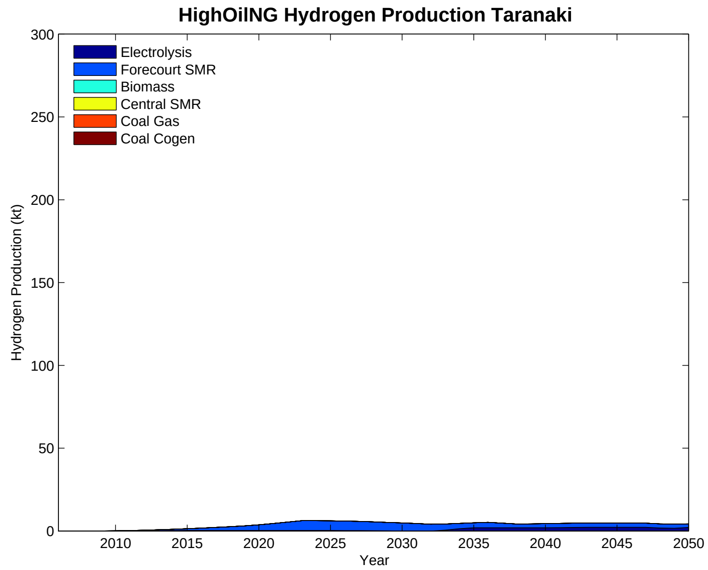

HighOilNG Hydrogen Production Hawke's Bay
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

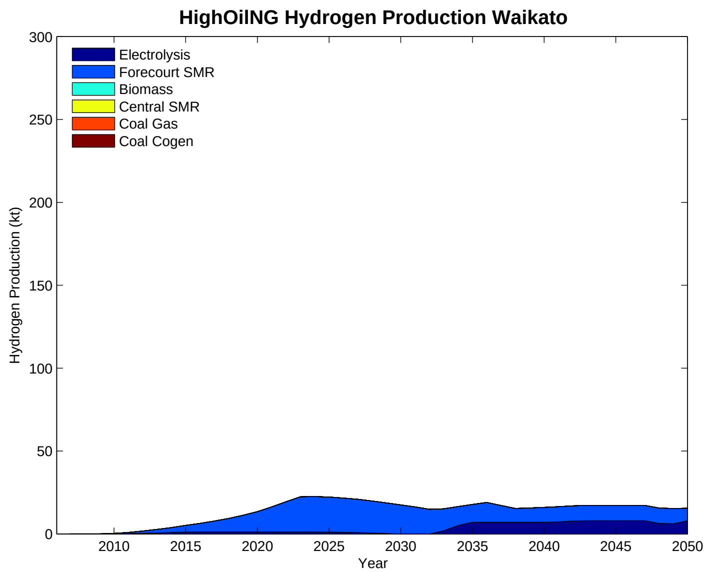

HighOilNG Hydrogen Production Nelson−Marlborough
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

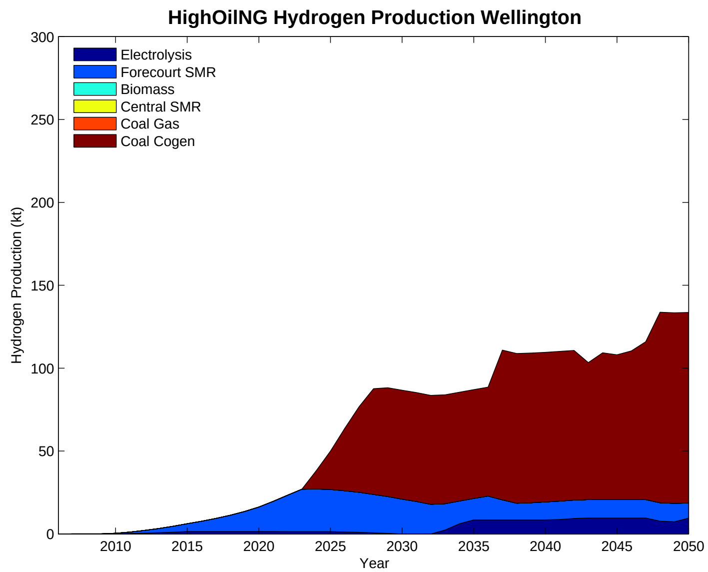

HighOilNG Hydrogen Production Northland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

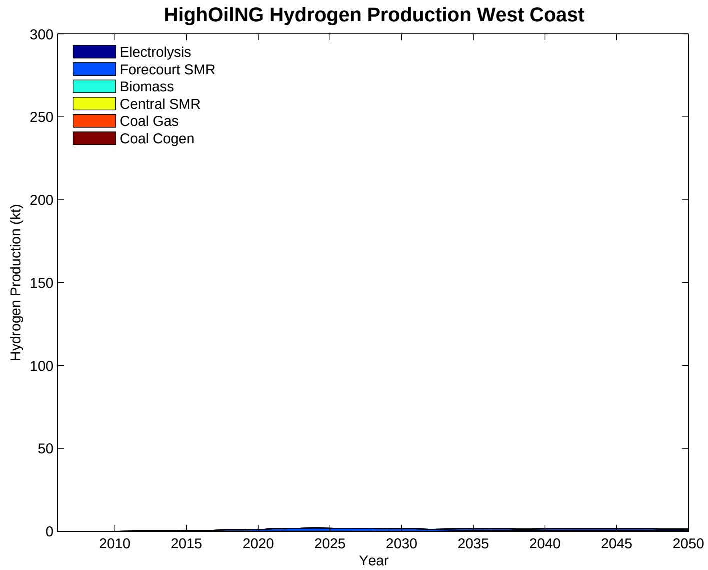

HighOilNG Hydrogen Production Otago−Southland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


HighOilNG Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

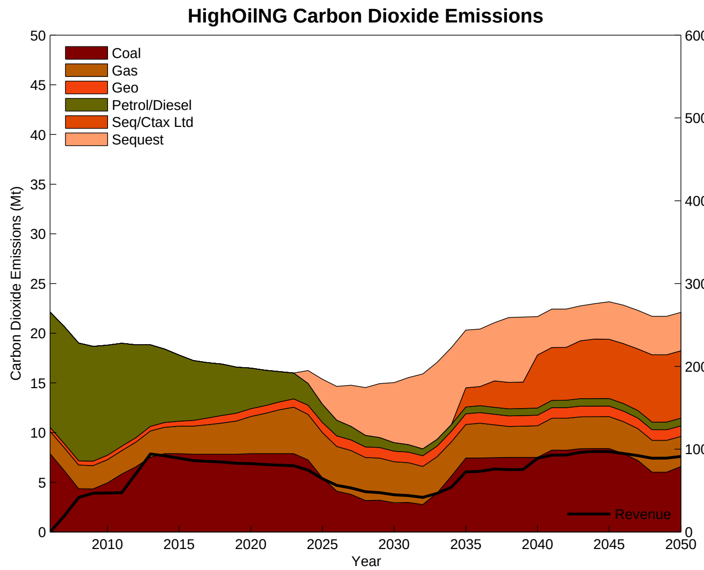

HighOilNG Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

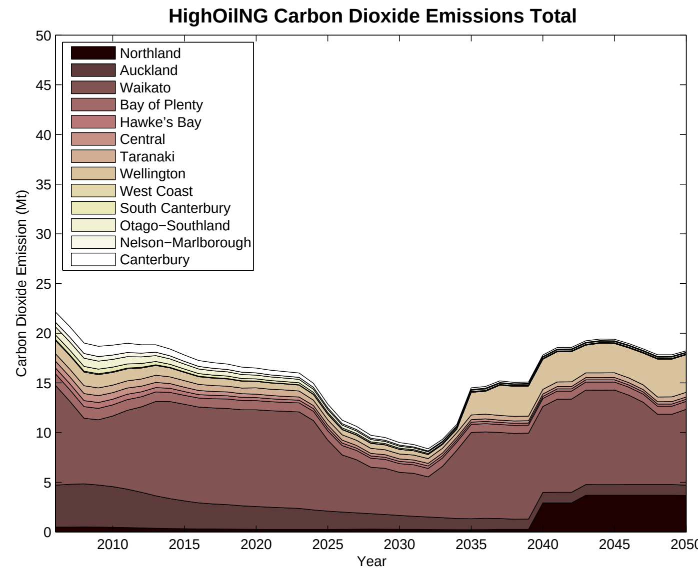

HighOilNG Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

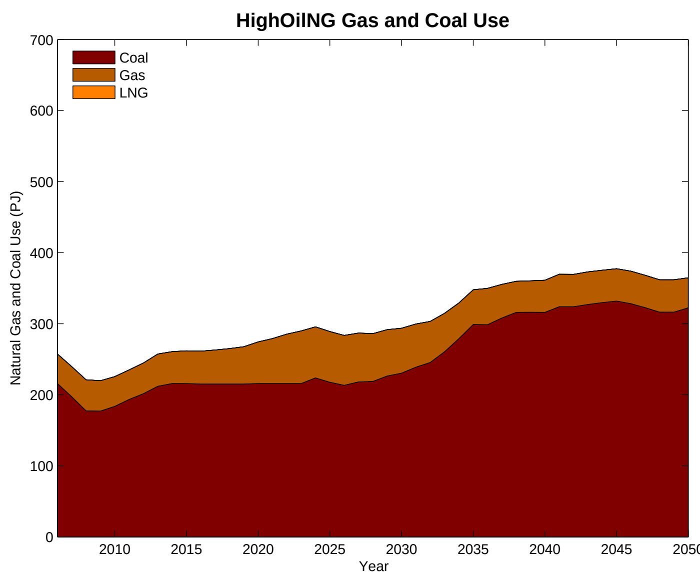

HighOilNG Hydrogen Production Wellington
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

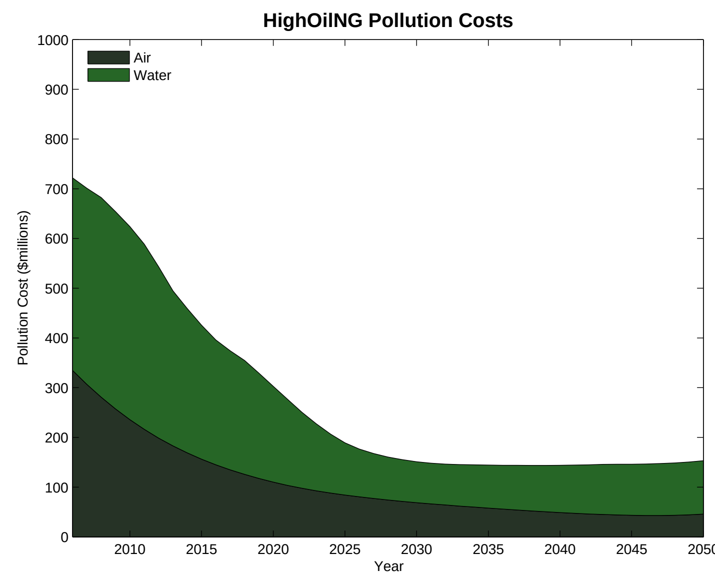

HighOilNG Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
300
250
200
150
100
50
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

Carbon Emissions - Energy Consumption and Pollution

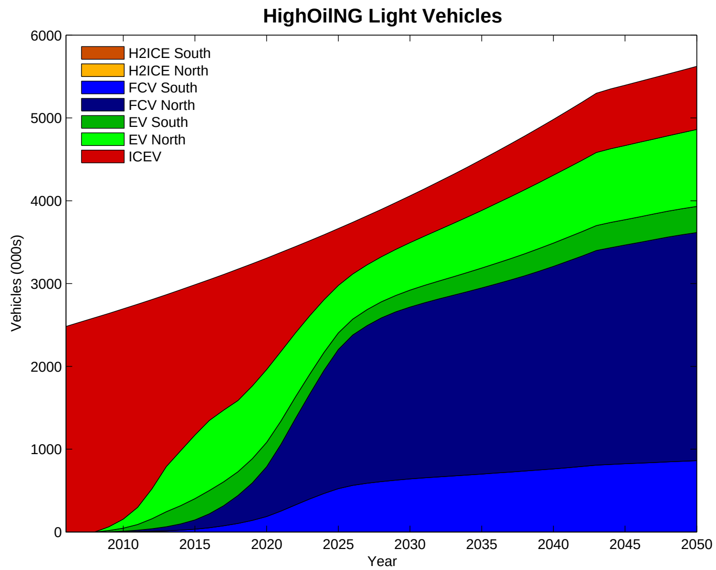


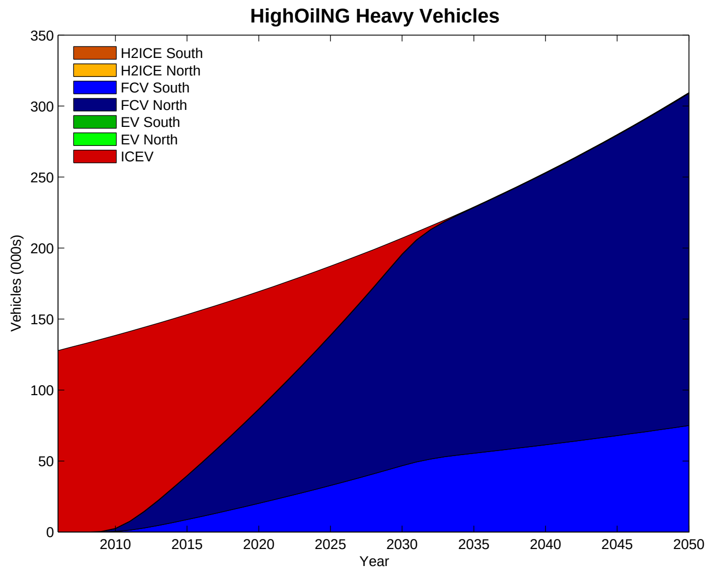


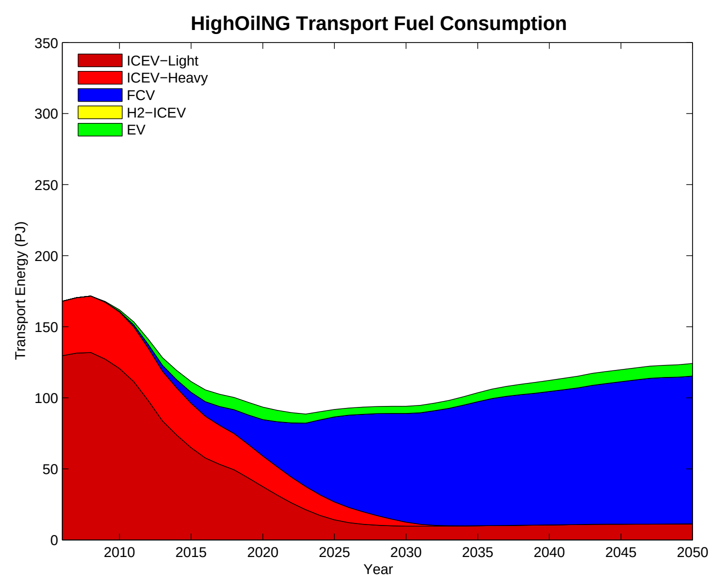




Transportation Sector





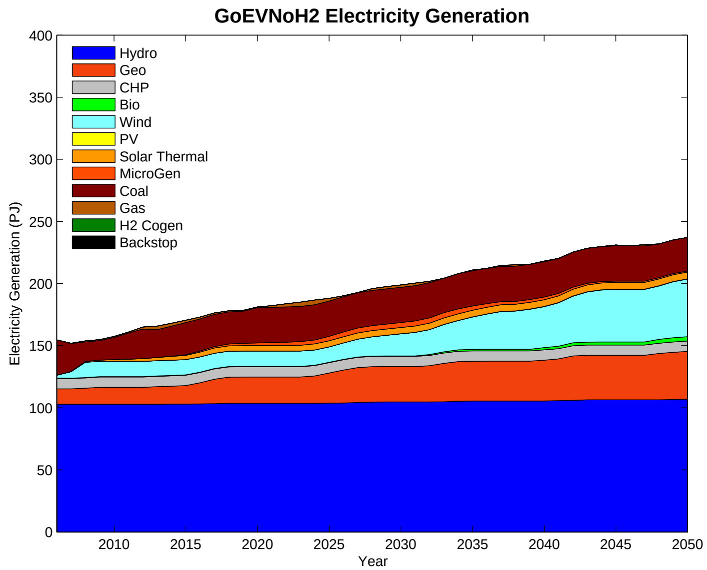


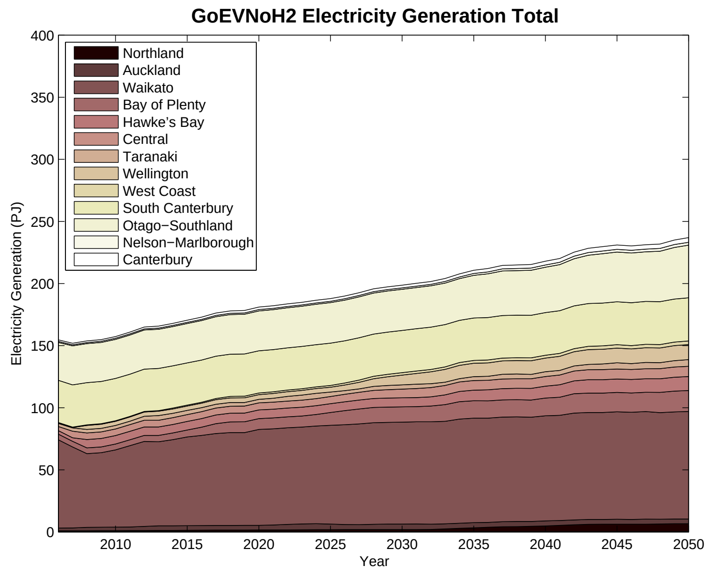
33 Scenario: No Hydrogen Production

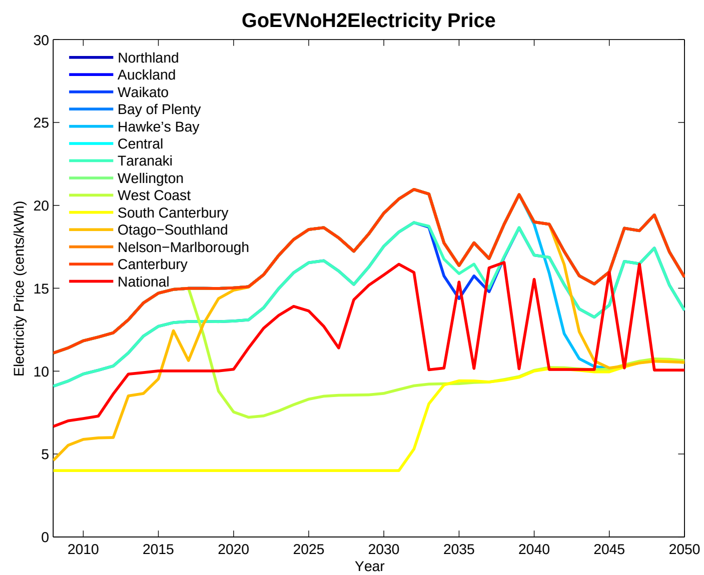
Key results for this scenario are:

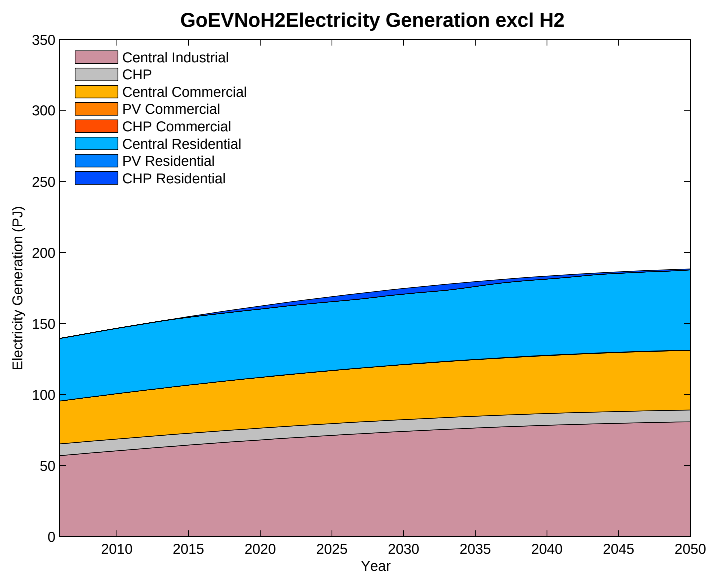
- National wholesale electricity price rises to 16.4 c/kWh in 2031 due the impact of the carbon tax and increasing demand from electric vehicles. After 2020 it averages 12.7 c/kWh to 2050.
- CO_2 emissions in 2050 are 40% below 2006 levels with no emissions being sequestered. No emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 82% in 2025 and 88% in 2050.
- Primary fossil fuel energy use decreases by 7% between 2006 and 2050.
- 68% of the light vehicle fleet switches to EVs by 2050. EVs begin to enter the market in significant numbers after 2012.
- The heavy vehicle fleet is entirely HFCVs by 2033.
- Air and water pollution costs reduce from $722 million in 2006 to $289 million in 2050.

The National Electricity Market

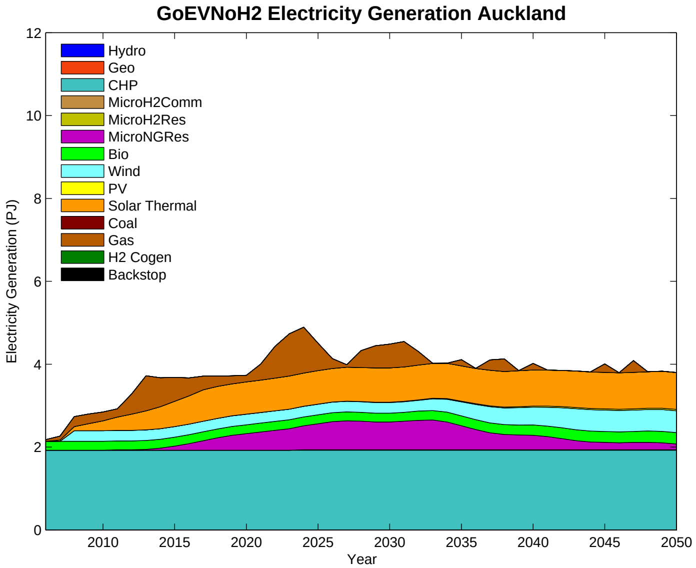


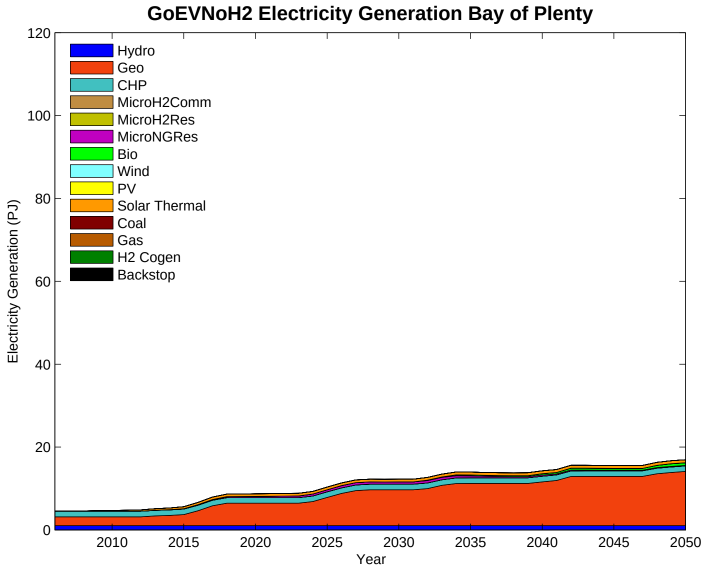


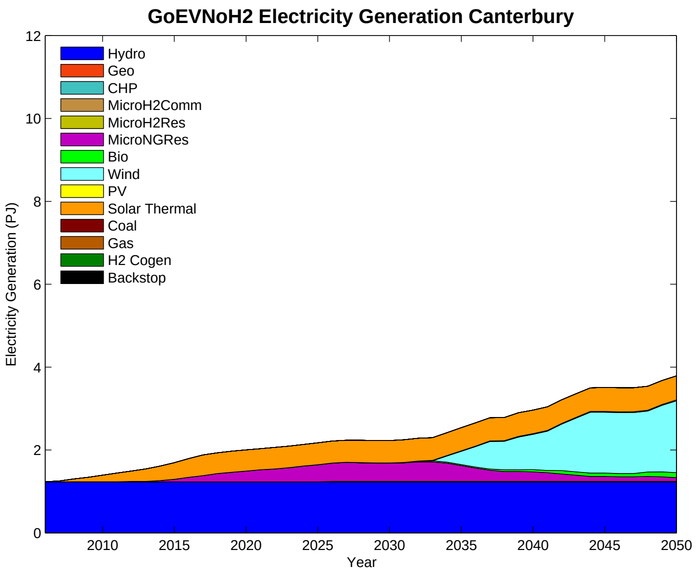


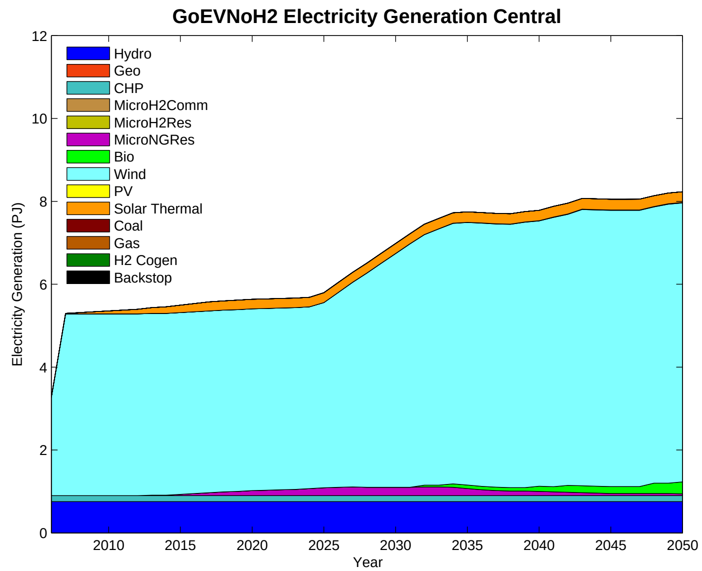


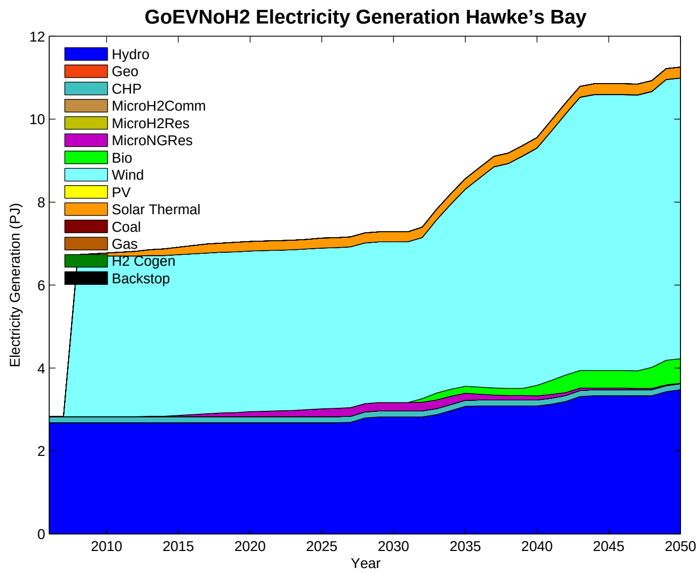
Regional Electricity Markets

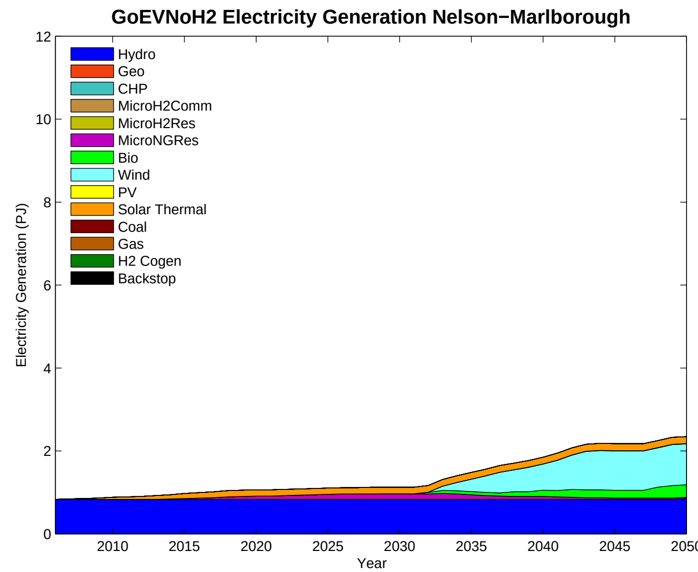


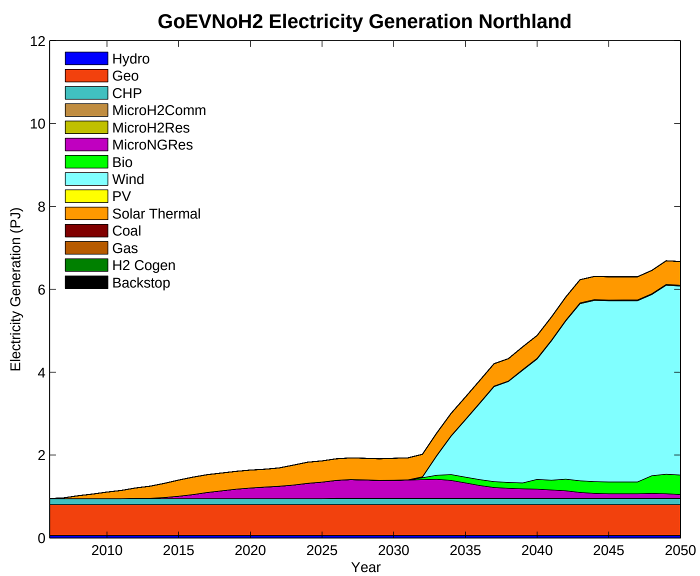







GoEVNoH2 Electricity Generation Hawke's Bay
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year


GoEVNoH2 Electricity Generation Nelson−Marlborough
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year


GoEVNoH2 Electricity Generation Northland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
2
4
6
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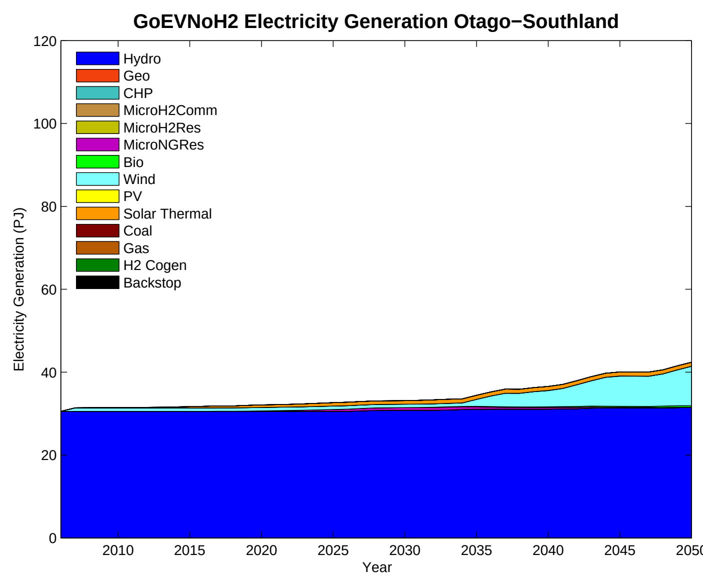
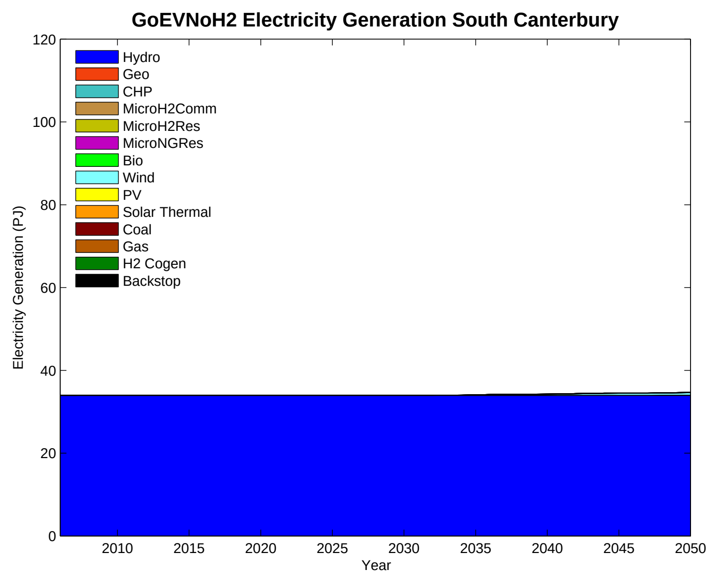
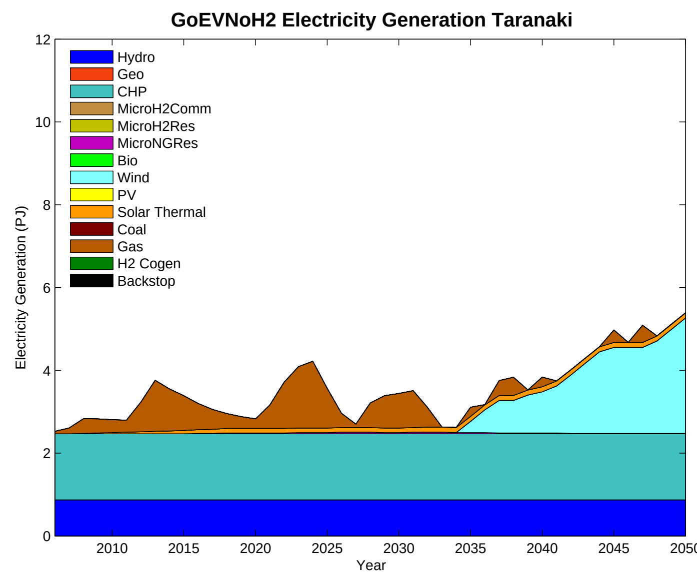
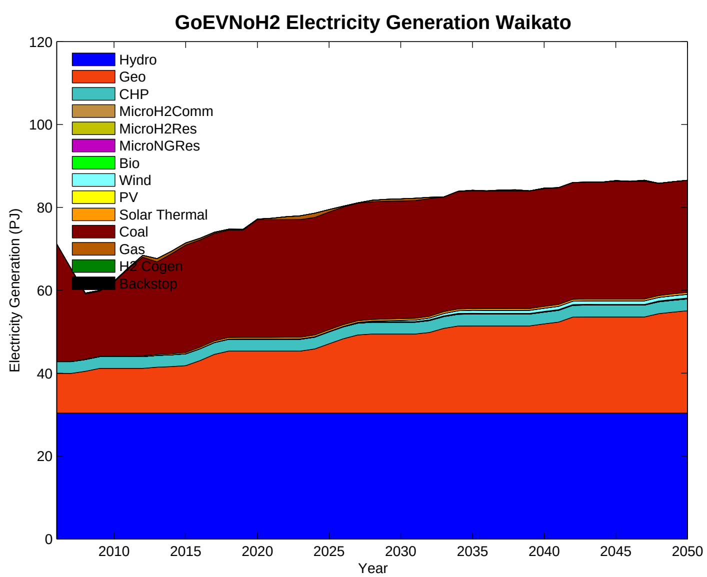
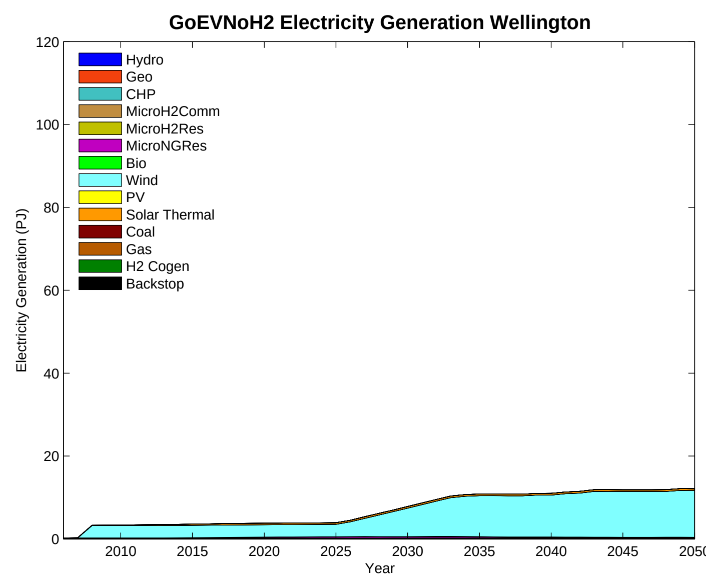
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

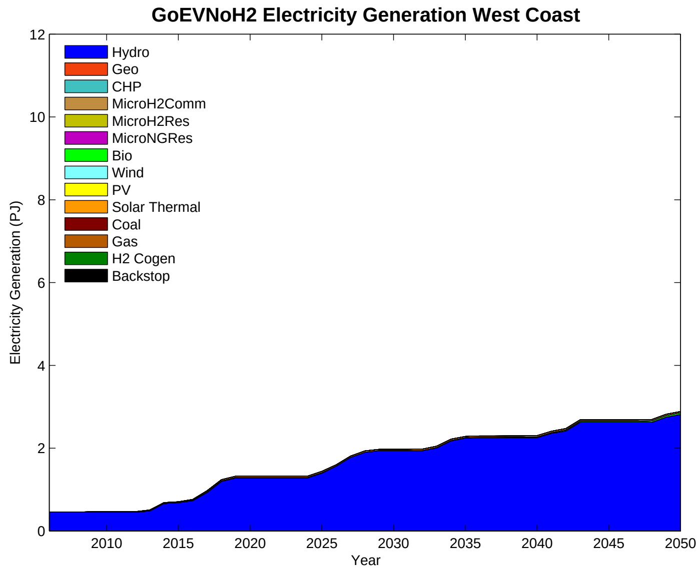

GoEVNoH2 Electricity Generation Otago−Southland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
20
40
60
80
100
120
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year


GoEVNoH2 Electricity Generation South Canterbury
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


GoEVNoH2 Electricity Generation Taranaki
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


GoEVNoH2 Electricity Generation Waikato
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


GoEVNoH2 Electricity Generation Wellington
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


GoEVNoH2 Electricity Generation West Coast
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
2
4
6
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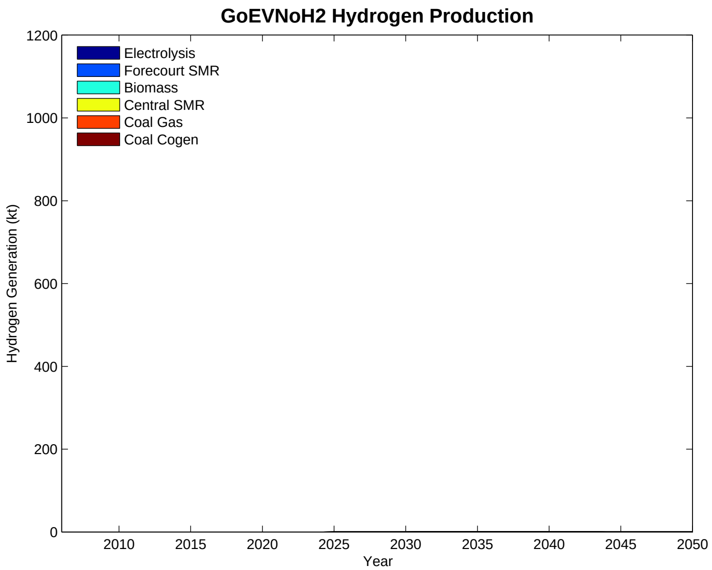
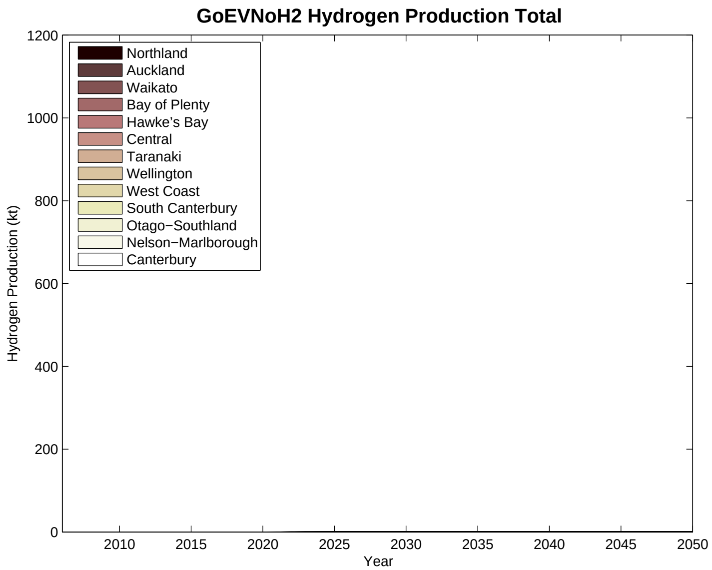
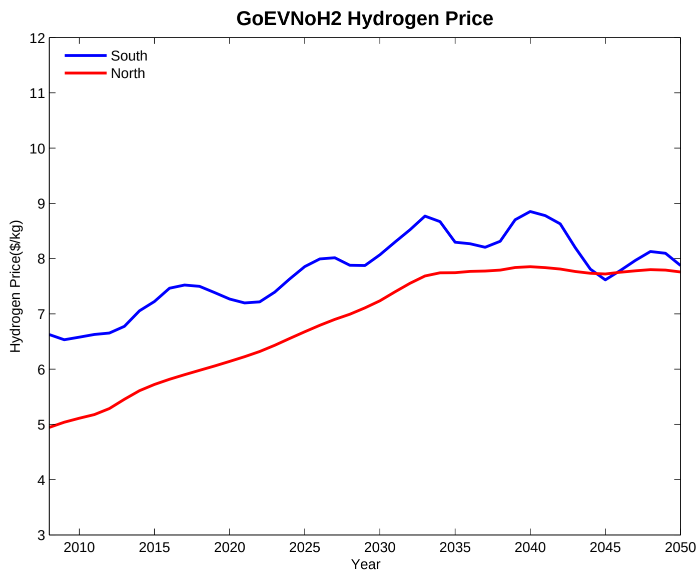
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

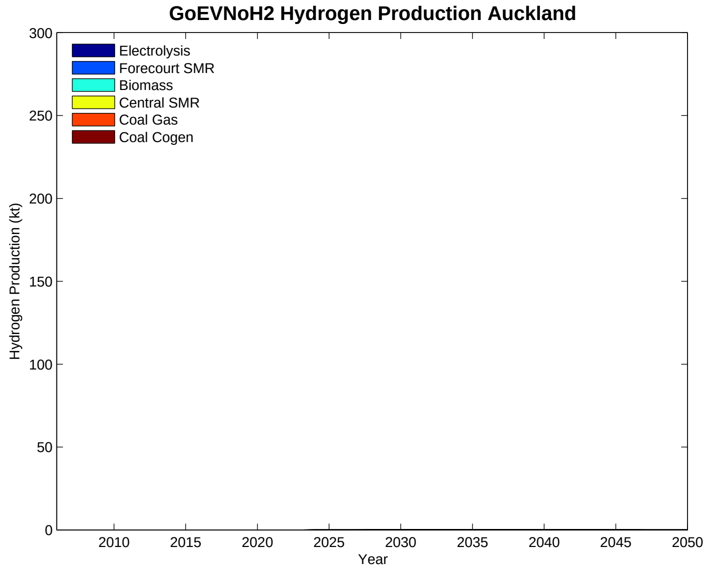
The National Hydrogen Market

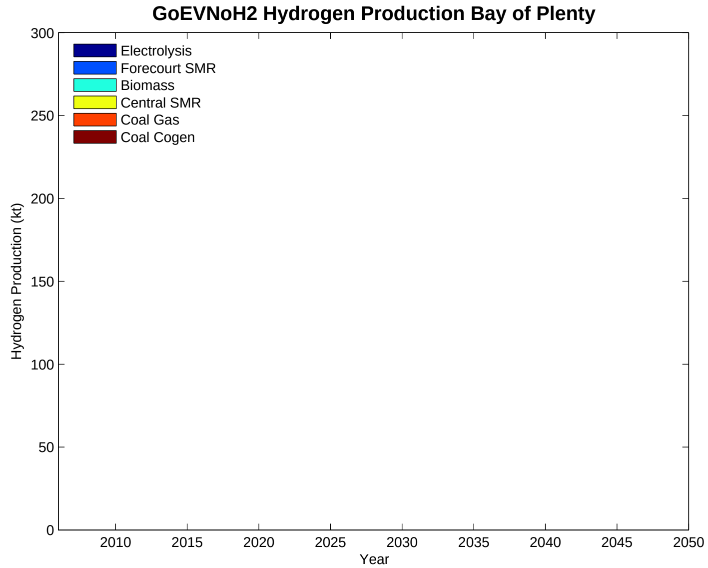


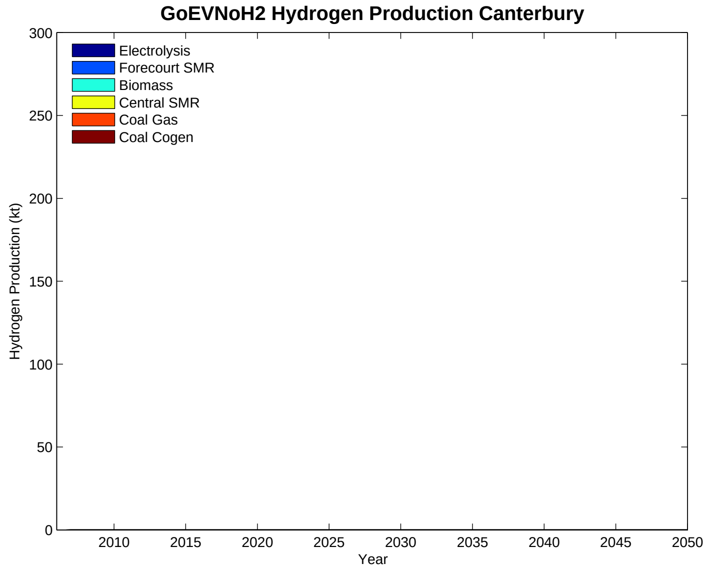


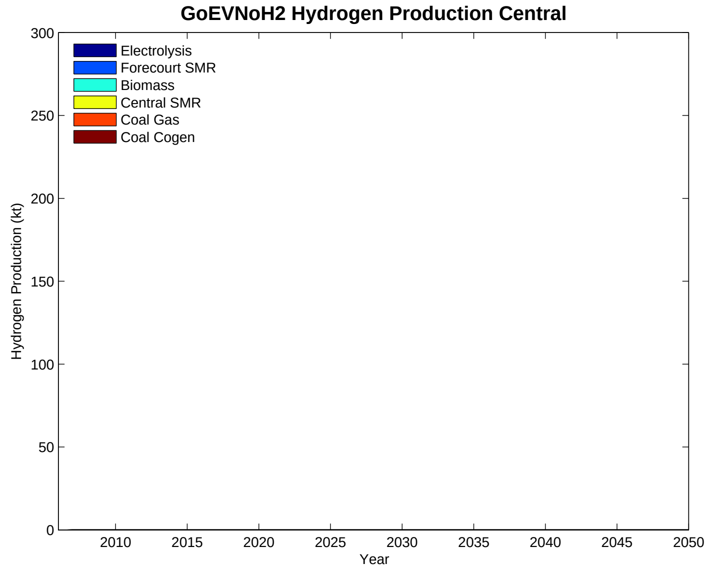


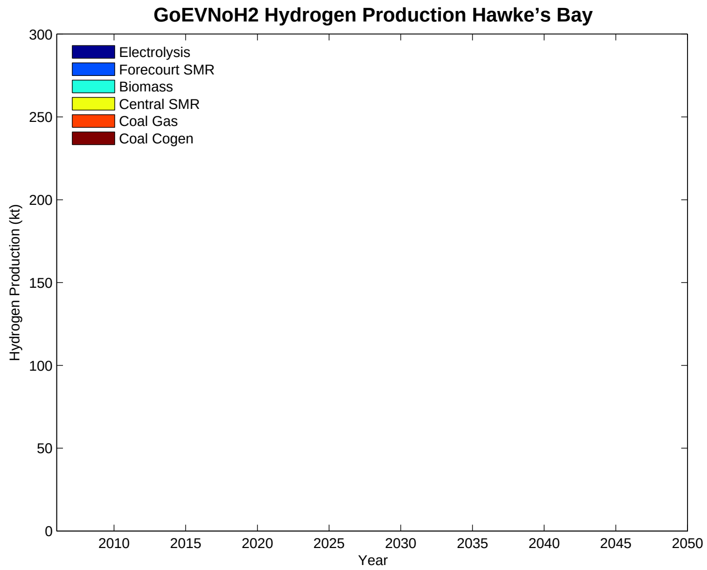
Regional Hydrogen Markets

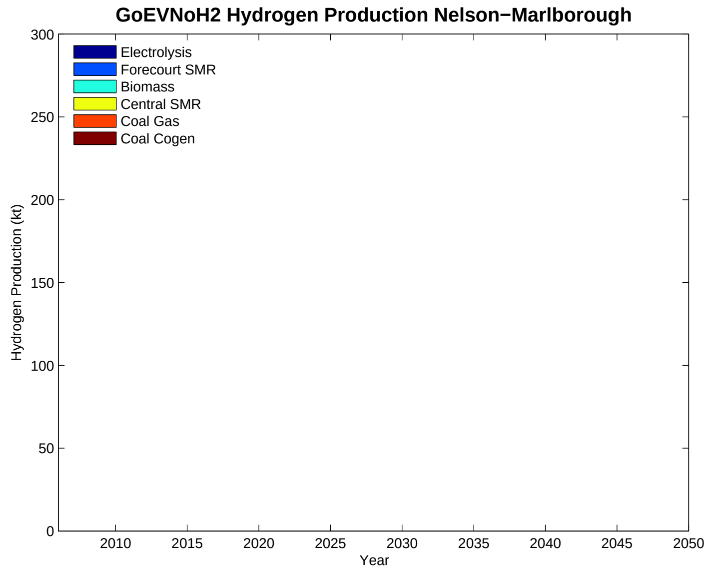


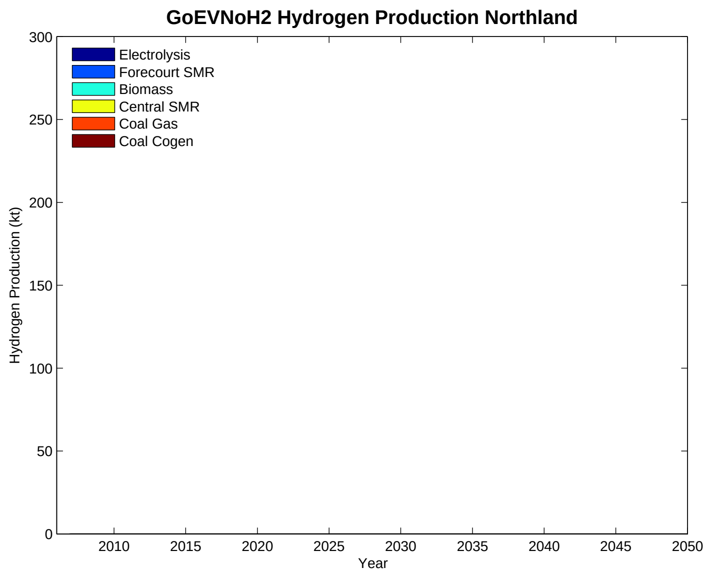


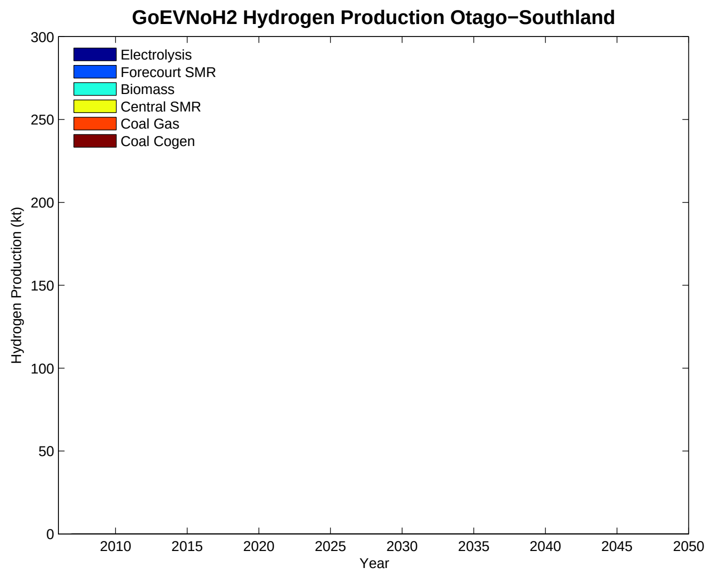





GoEVNoH2 Hydrogen Production Hawke’s Bay
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


GoEVNoH2 Hydrogen Production Nelson−Marlborough
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


GoEVNoH2 Hydrogen Production Northland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year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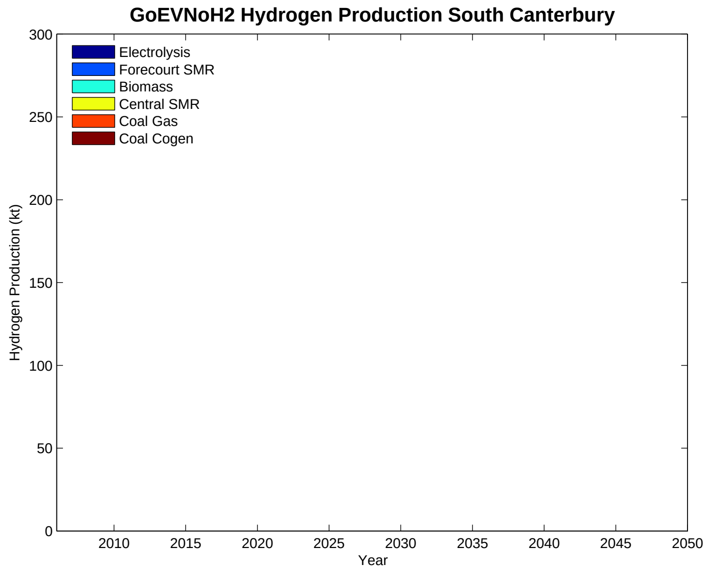
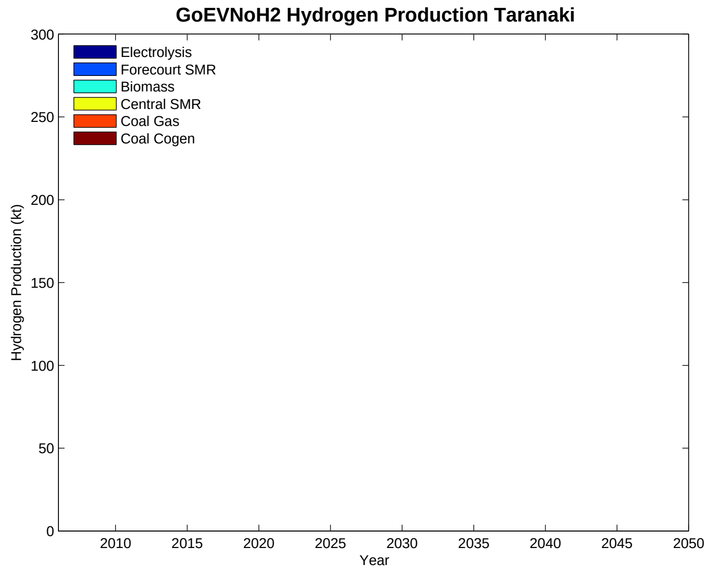
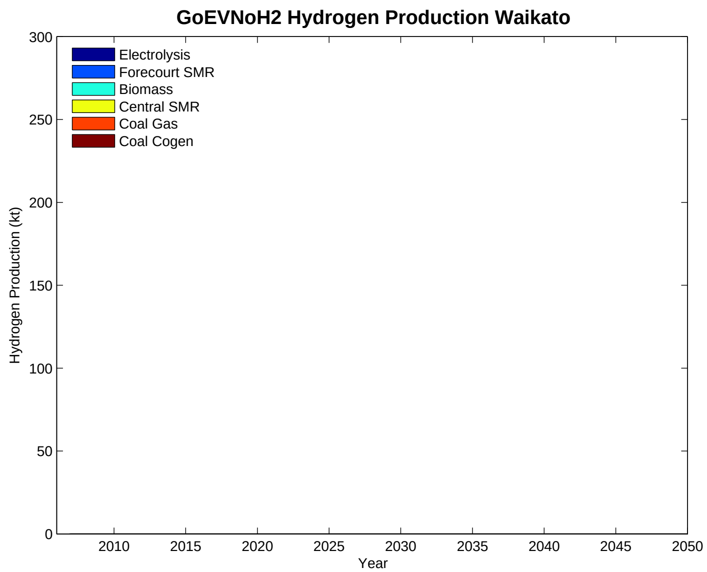
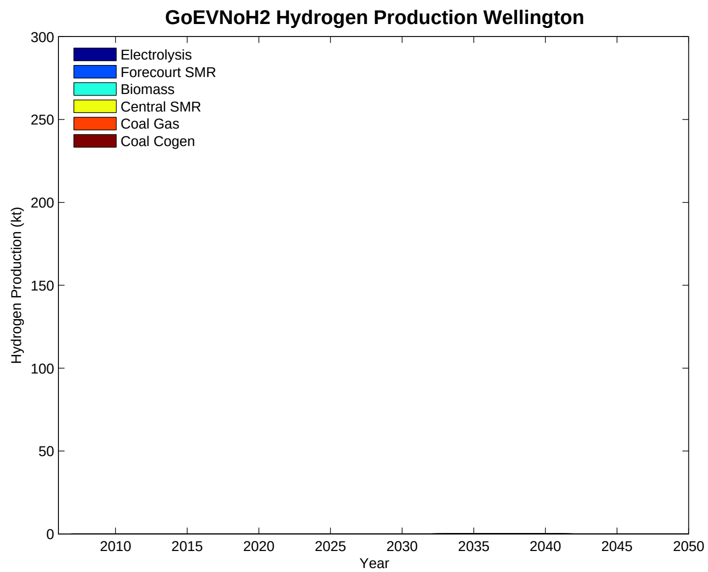
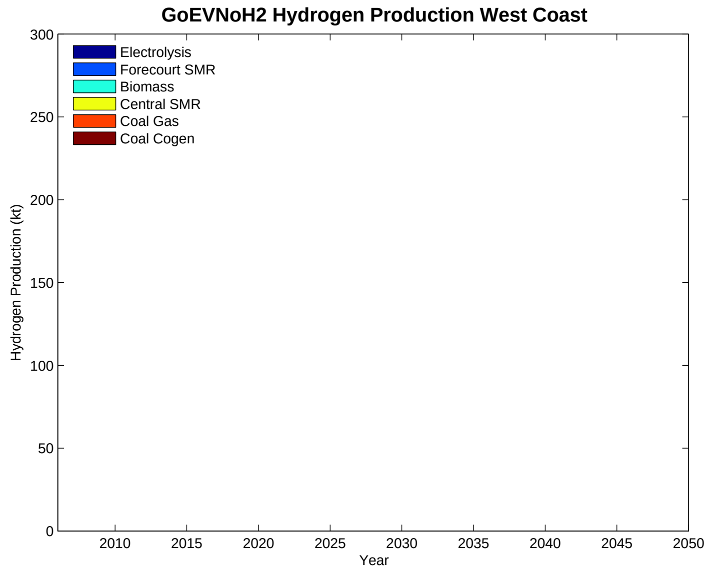
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


GoEVNoH2 Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

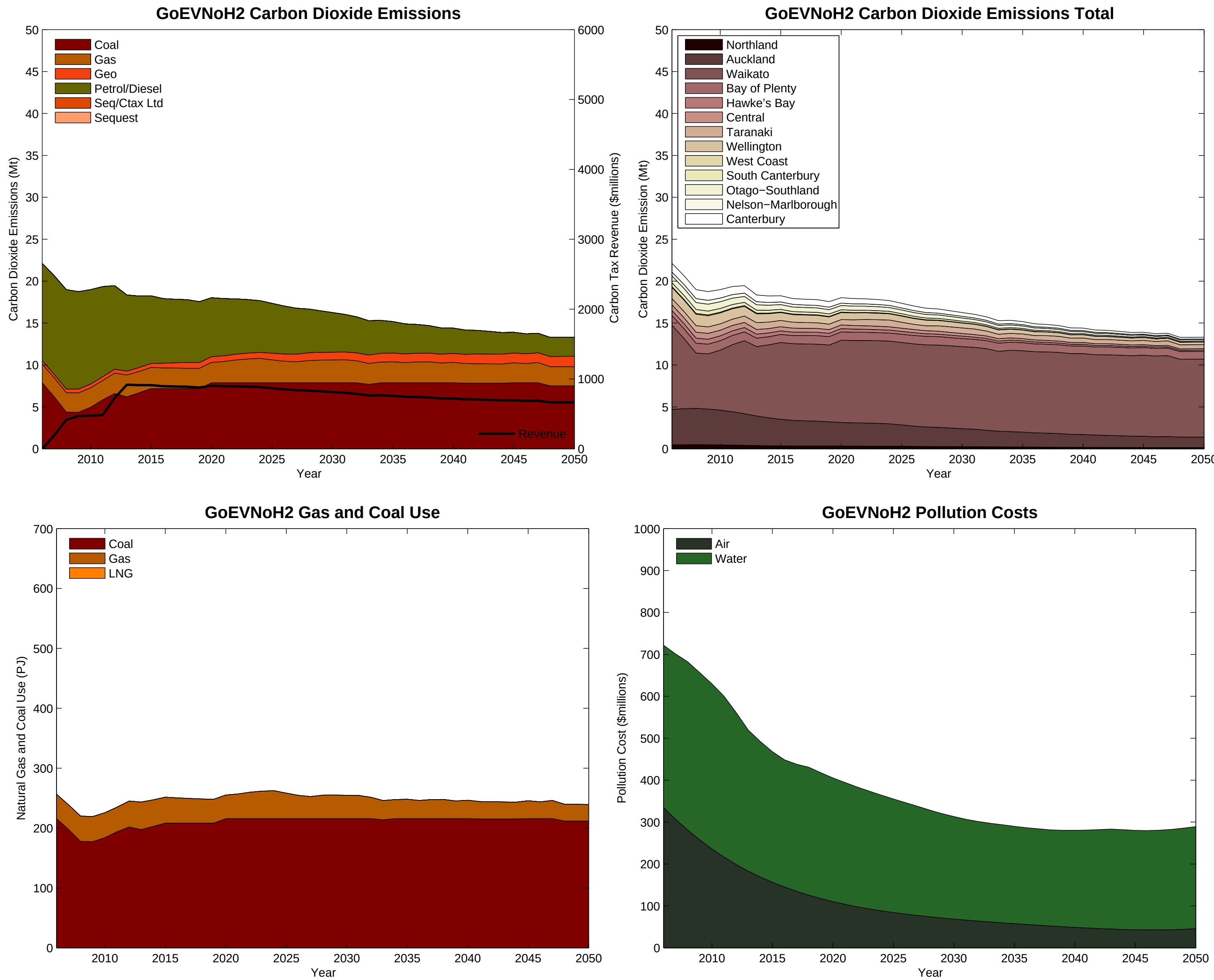

GoEVNoH2 Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050


GoEVNoH2 Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

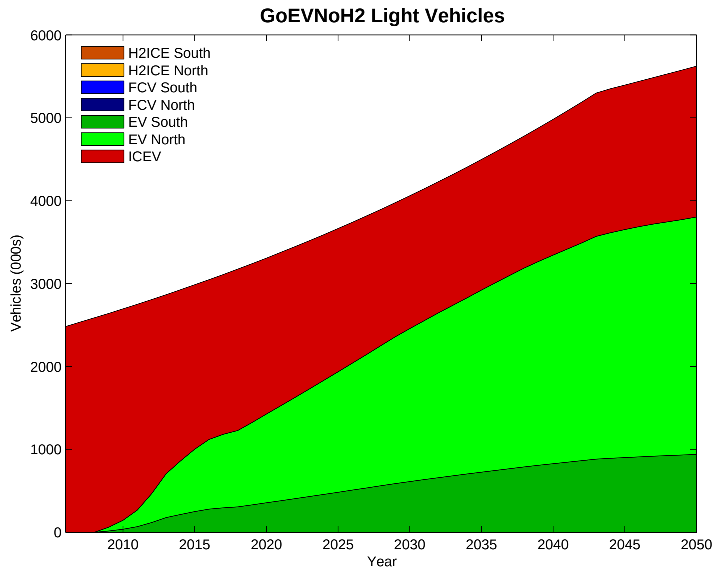

GoEVNoH2 Hydrogen Production Wellington
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050

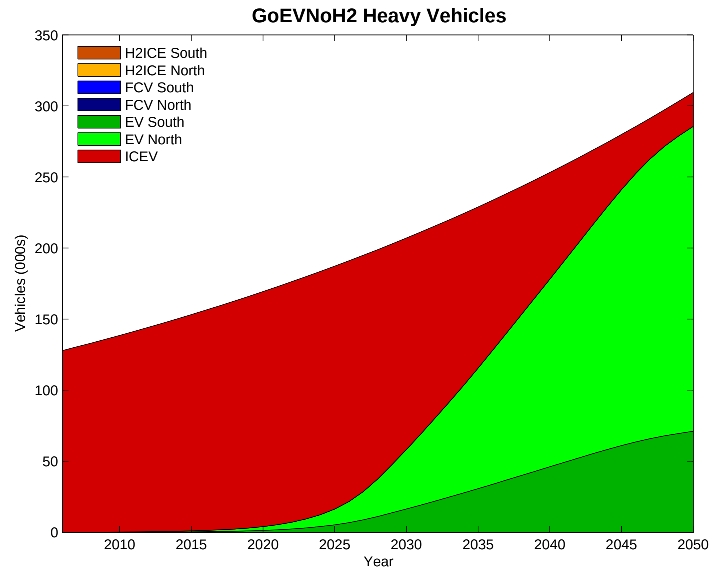

GoEVNoH2 Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
0
50
100
150
200
250
300
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

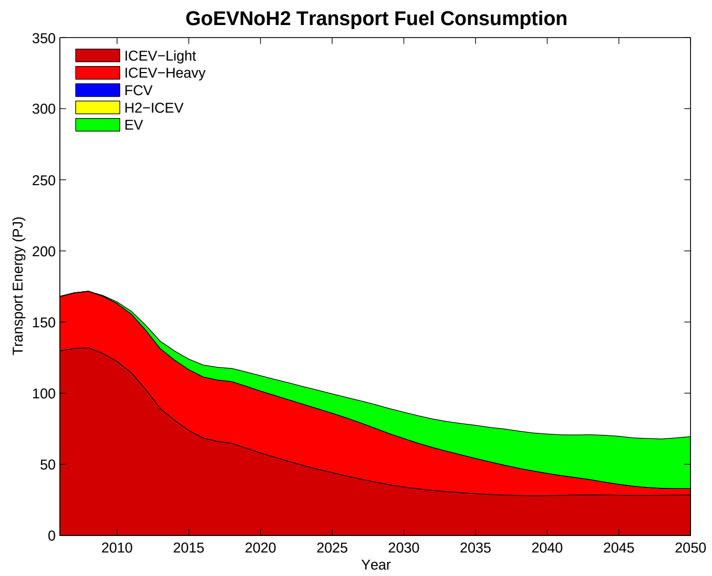
Carbon Emissions - Energy Consumption and Pollution



Transportation Sector





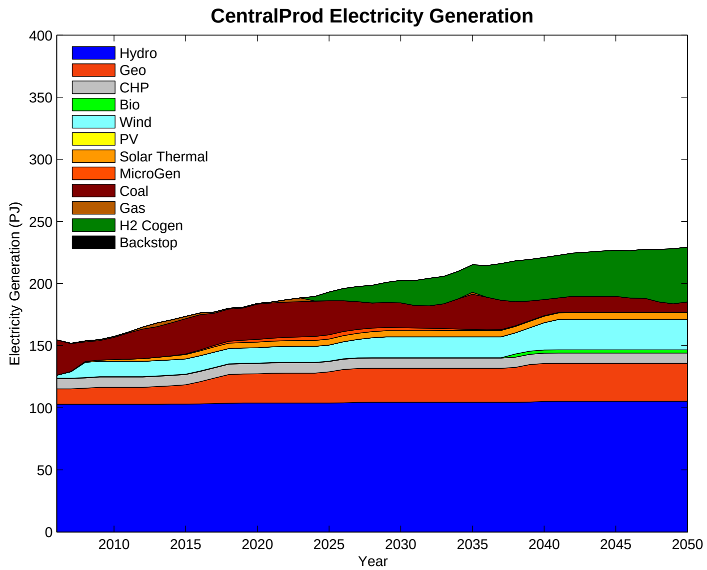


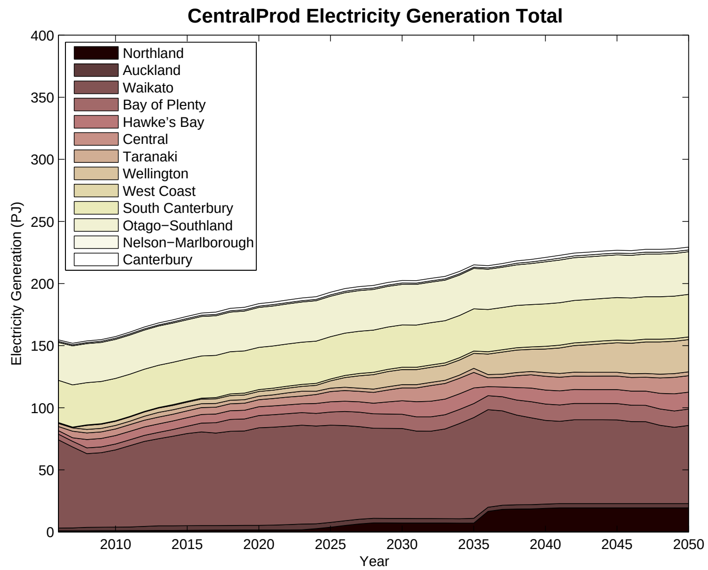
34 Scenario: Subsidised central production

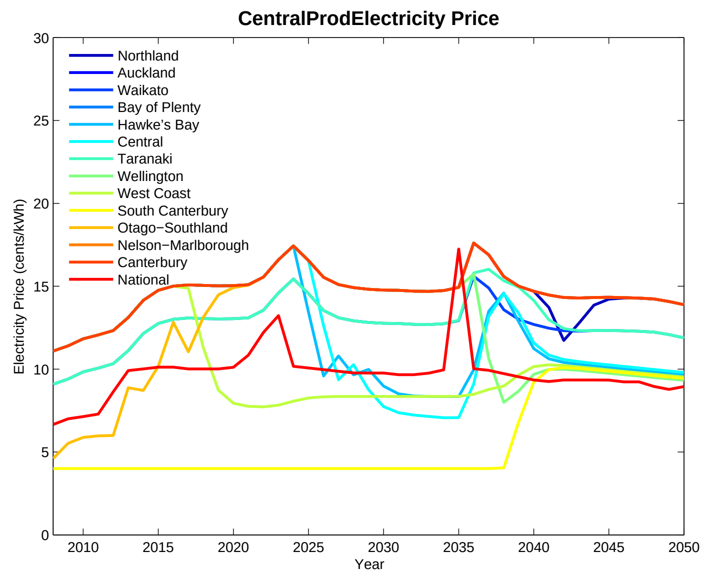
Key results for this scenario are:

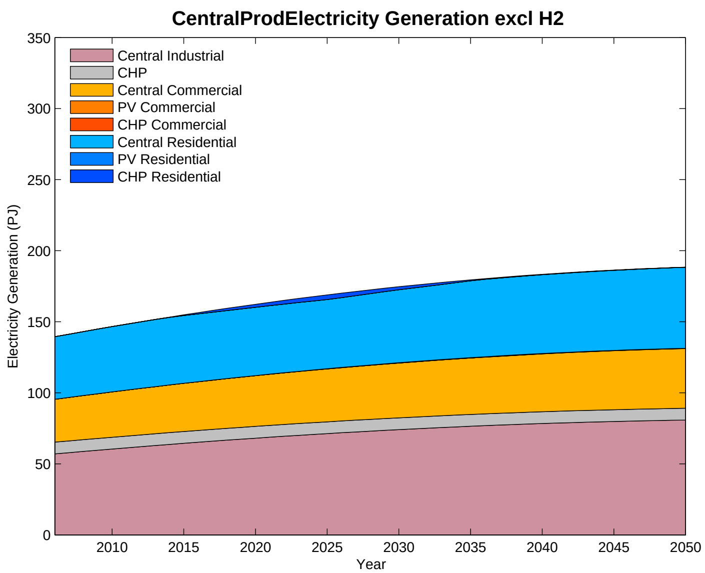
- National wholesale electricity price rises to 9.9 c/kWh in 2013 due the impact of the carbon tax. The price remains at this level to 2032 and then slowly declines to 8.7 c/kWh in 2050 due to the maintenance of excess capacity in the system. A brief peak of 17.2 c/kWh occurs in 2035 due to the electricity demand of producing hydrogen by electrolysis. The average electricity price after 2020 is 10.1 c/kWh.
- CO_2 emissions in 2050 are 15% below 2006 levels with 17% of total emissions being sequestered. A further 62% of emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 80% in 2025 and 77% in 2050.
- Hydrogen generation in 2050 consists of 6% electrolysis, 27% biomass gasification, and 67% coal cogeneration.
- Primary fossil fuel energy use increases by 44% between 2006 and 2050.
- 65% of the light vehicle fleet switches to HFCVs by 2050 with 22% switching to EVs. EVs and HFCVs begin to enter the market in significant numbers after 2012 and 2020 respectively, when growth is rapid due to the reducing capital cost of fuel cells and increasing oil price.
- The heavy vehicle fleet is entirely HFCVs by 2033.
- Air and water pollution costs reduce from $722 million in 2006 to $152 million in 2050.

The National Electricity Market

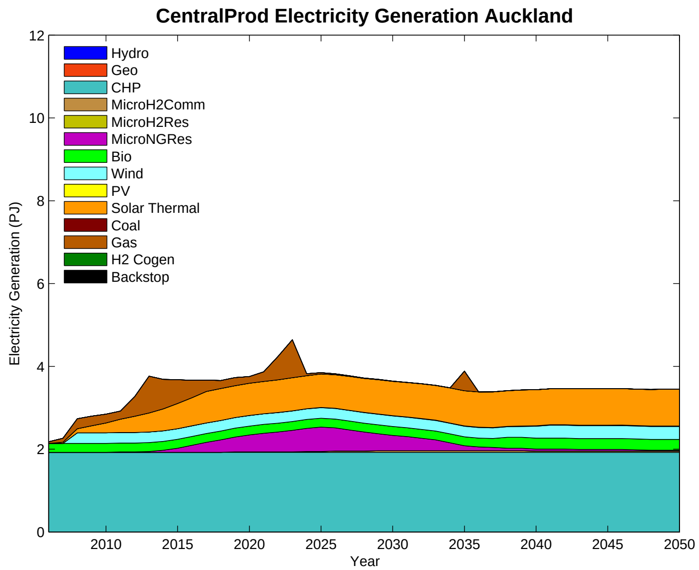


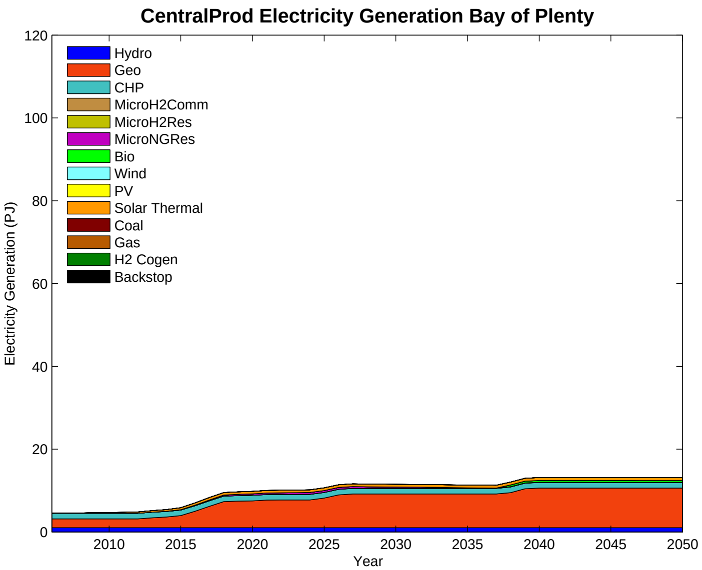


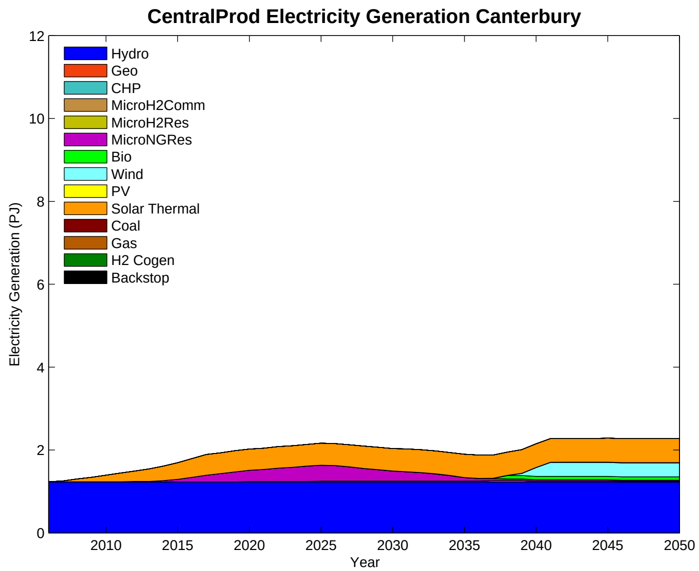


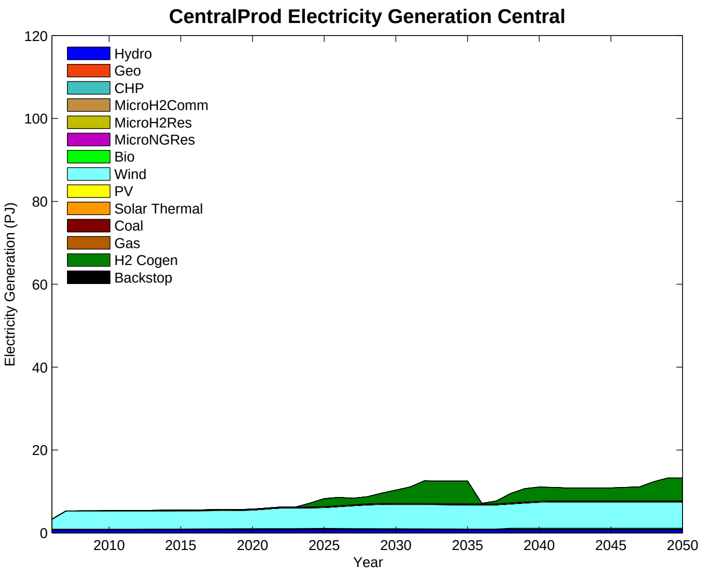


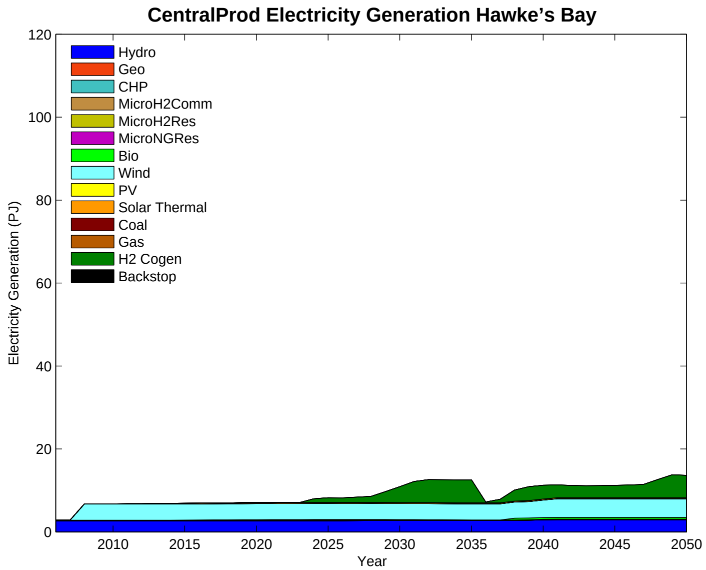
Regional Electricity Markets

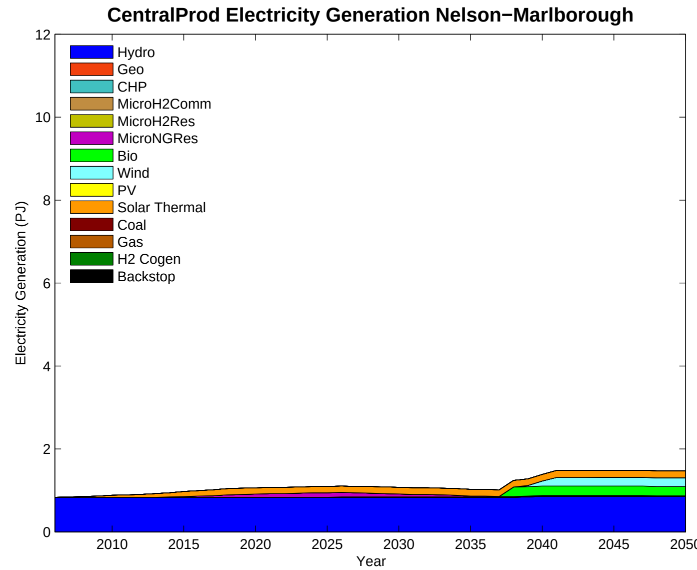


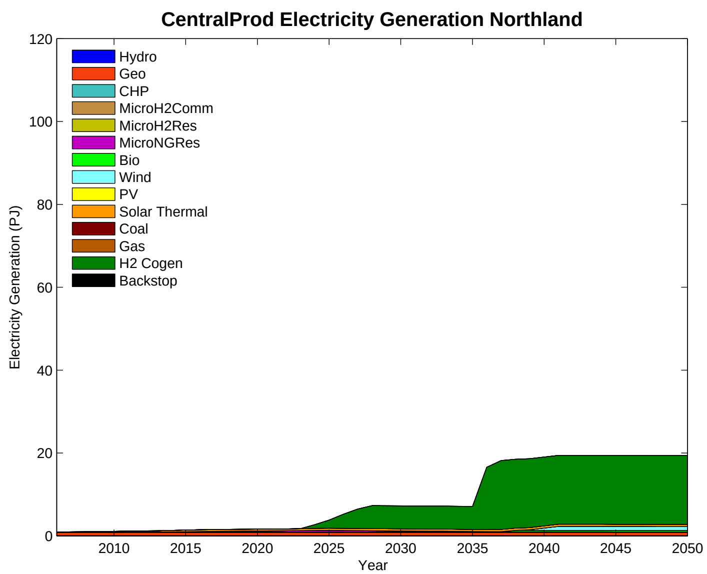


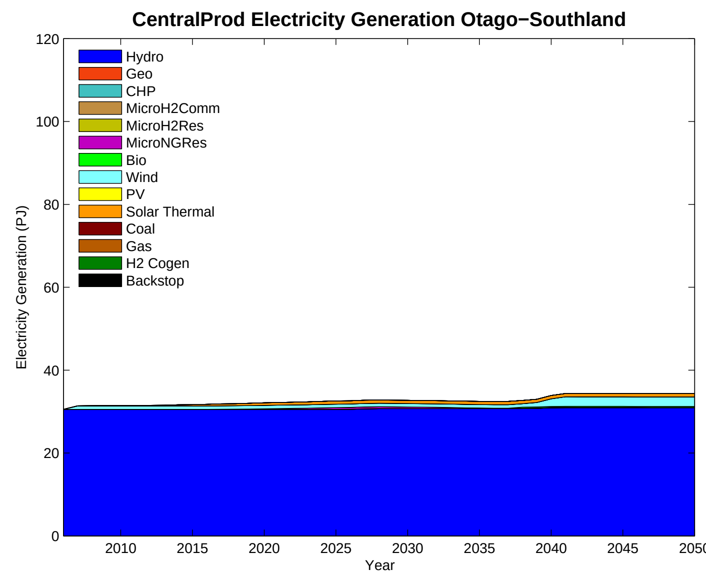


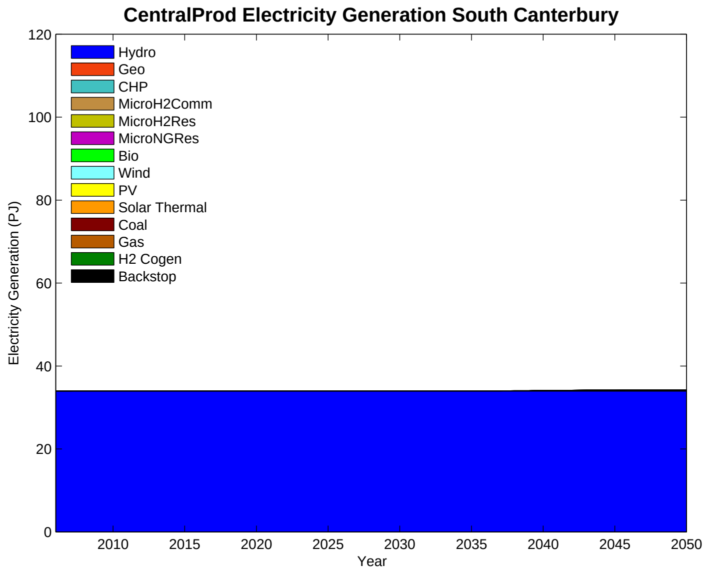


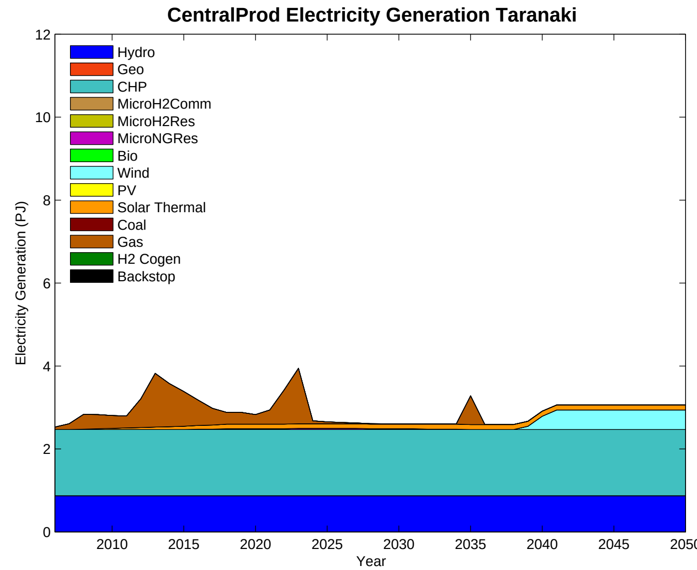

CentralProd Electricity Generation Hawke's Bay
Electricity Generation (PJ)
Year
0
20
40
60
80
100
120
2010
2015
2020
2025
2030
2035
2040
2045
2050
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

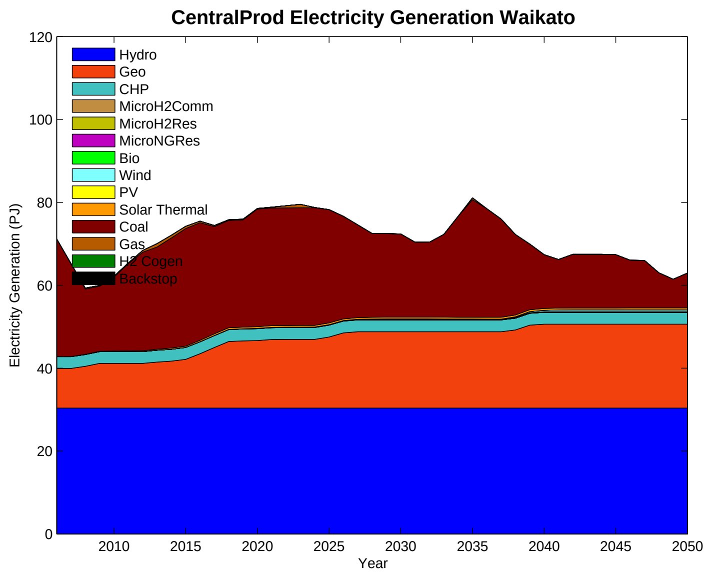

CentralProd Electricity Generation Nelson−Marlborough
Electricity Generation (PJ)
Year
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

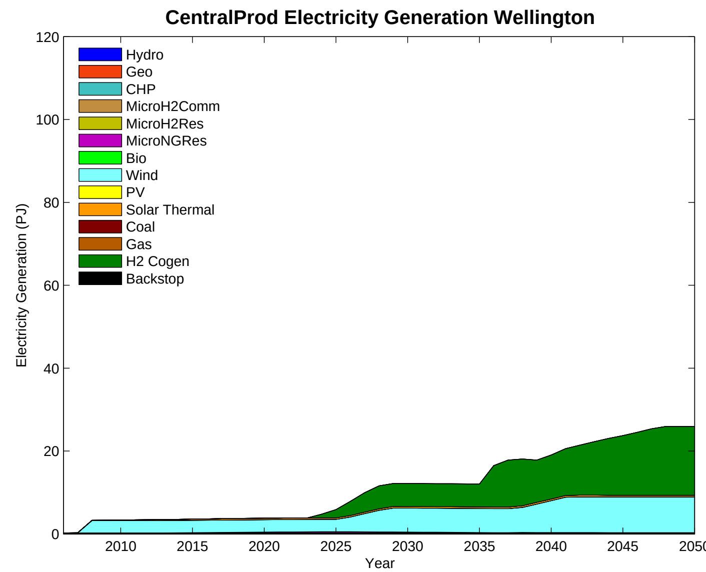

CentralProd Electricity Generation Northland
Electricity Generation (PJ)
Year
0
20
40
60
80
100
120
2010
2015
2020
2025
2030
2035
2040
2045
2050
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

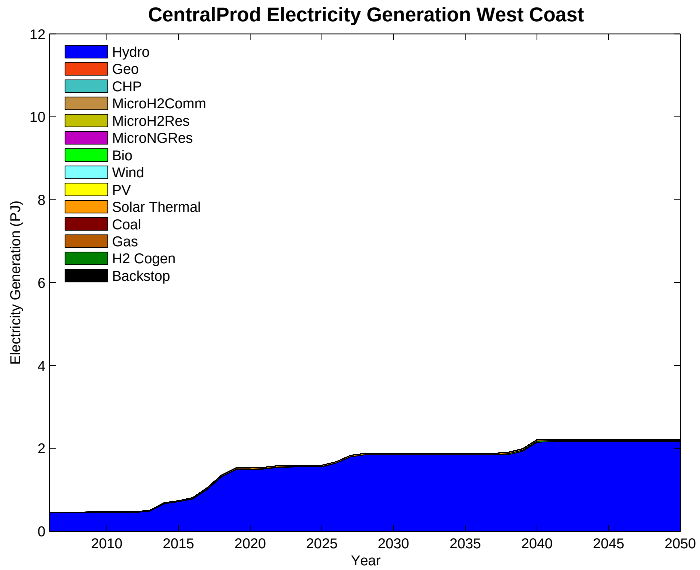

CentralProd Electricity Generation Otago−Southland
Electricity Generation (PJ)
Year
0
20
40
60
80
100
120
2010
2015
2020
2025
2030
2035
2040
2045
2050
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


CentralProd Electricity Generation South Canterbury
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year


CentralProd Electricity Generation Taranaki
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

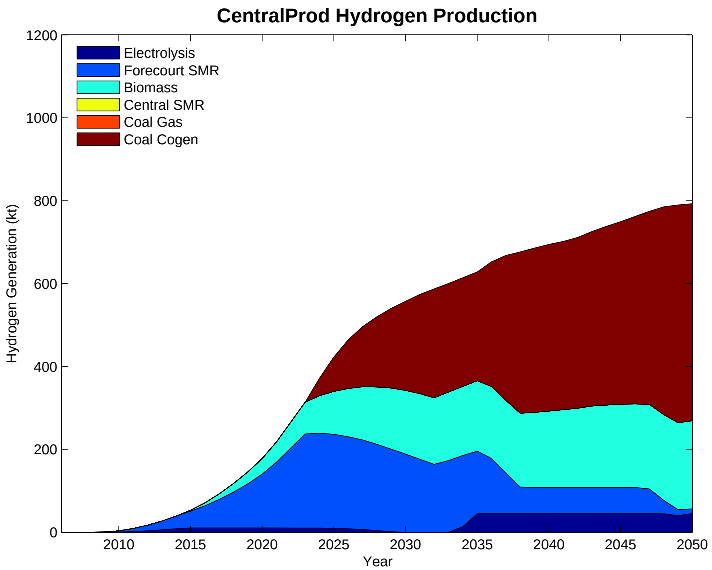

CentralProd Electricity Generation Waikato
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

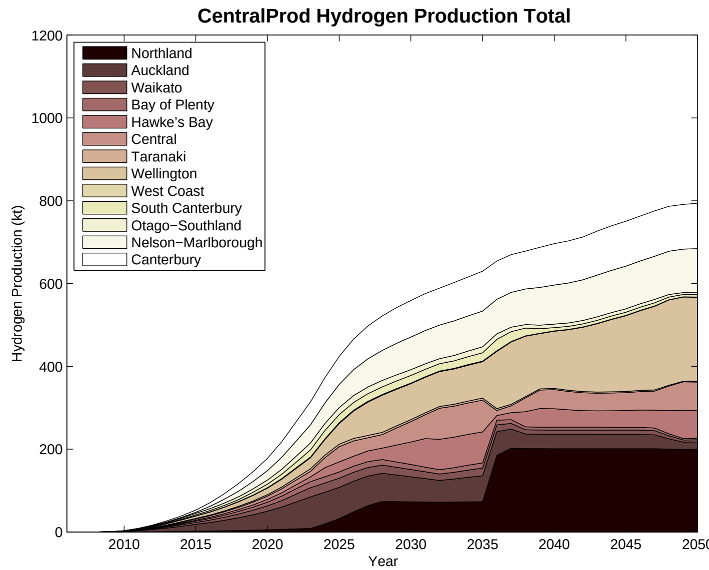

CentralProd Electricity Generation Wellington
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
Year

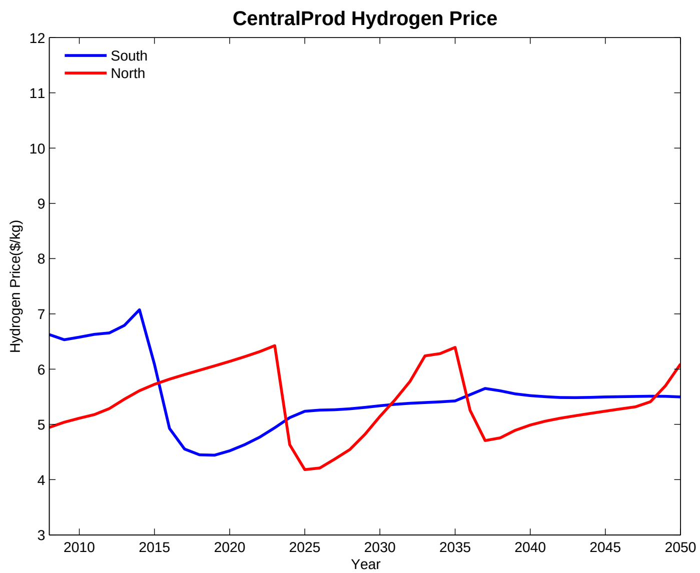


CentralProd Electricity Generation West Coast
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
2
4
6
8
10
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

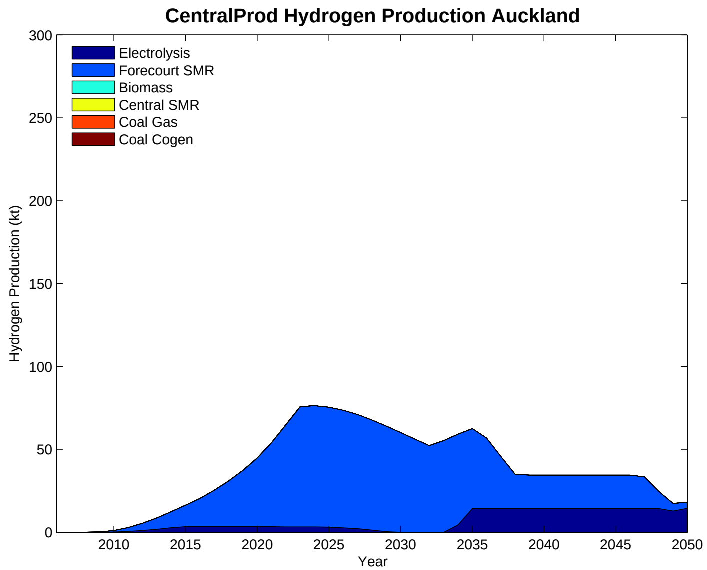
The National Hydrogen Market

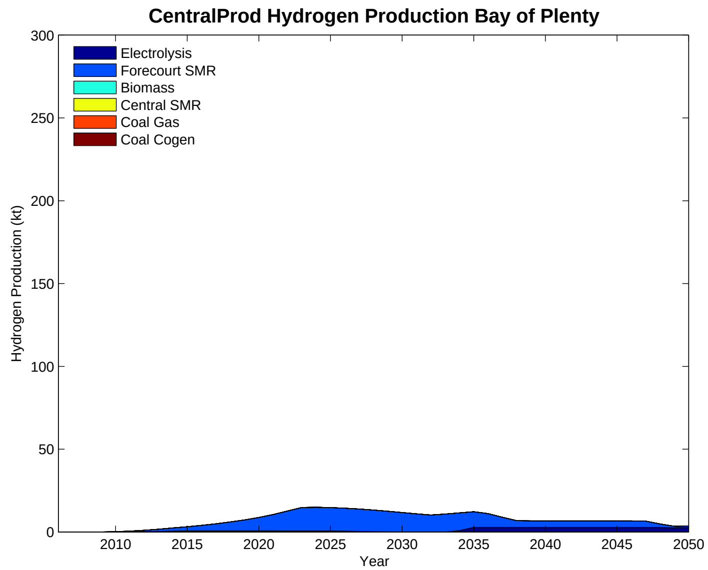


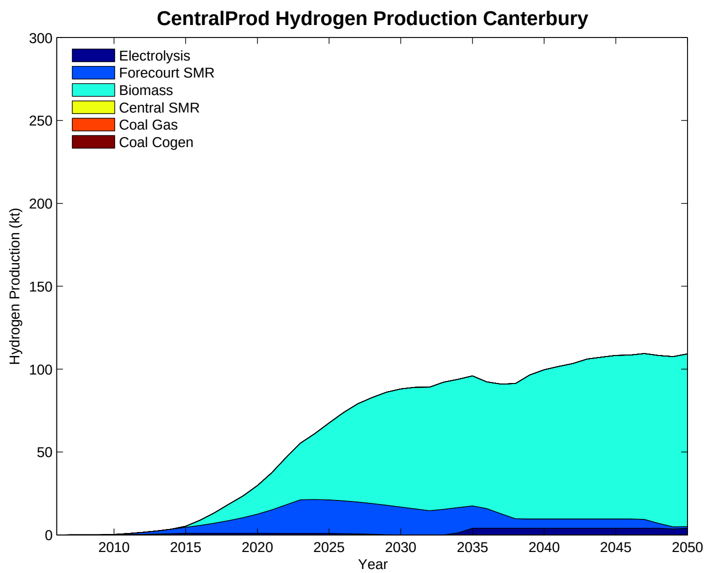


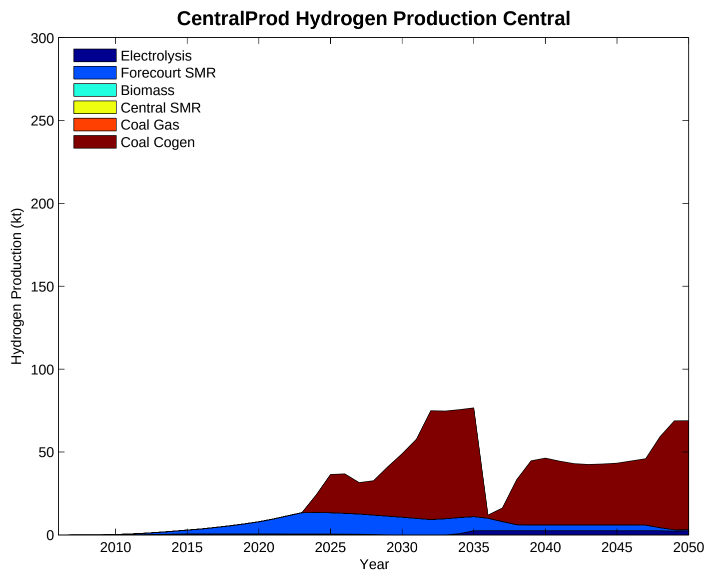


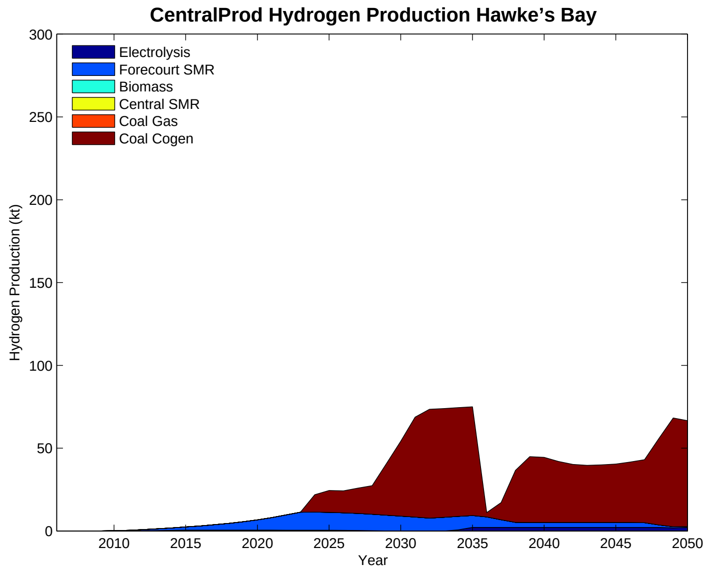
Regional Hydrogen Markets

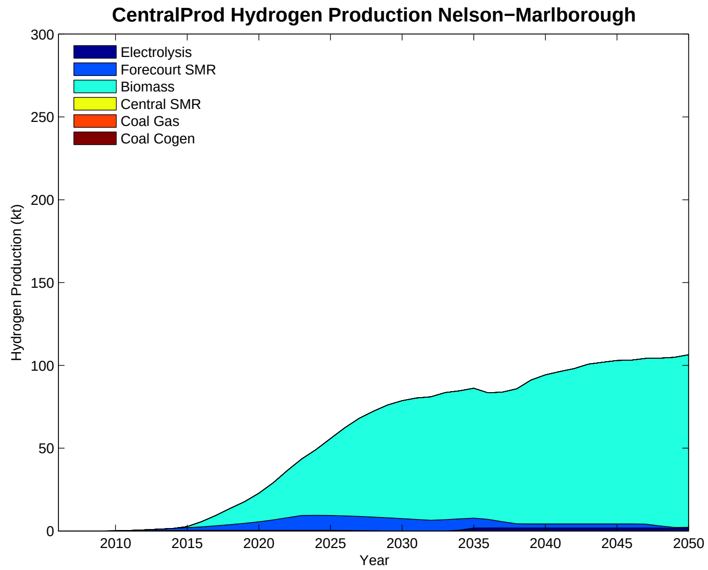


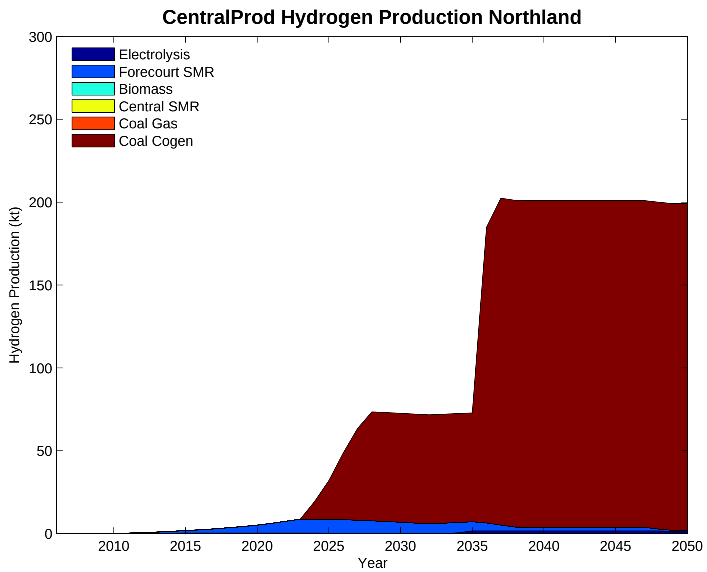


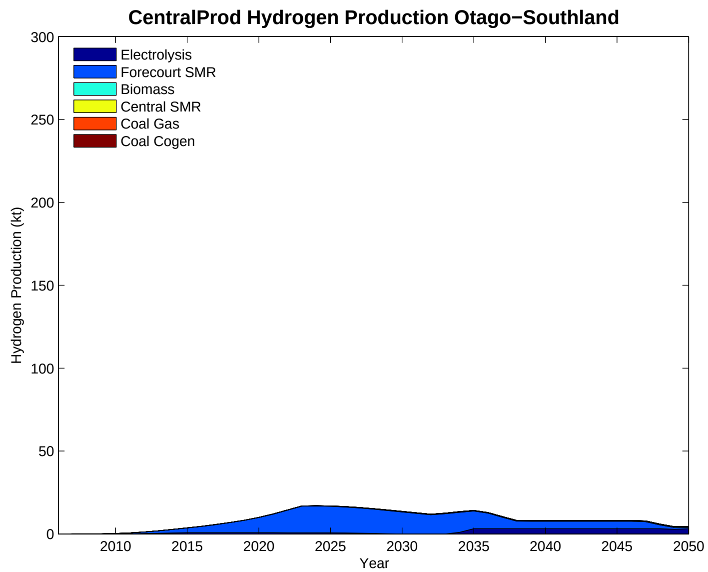


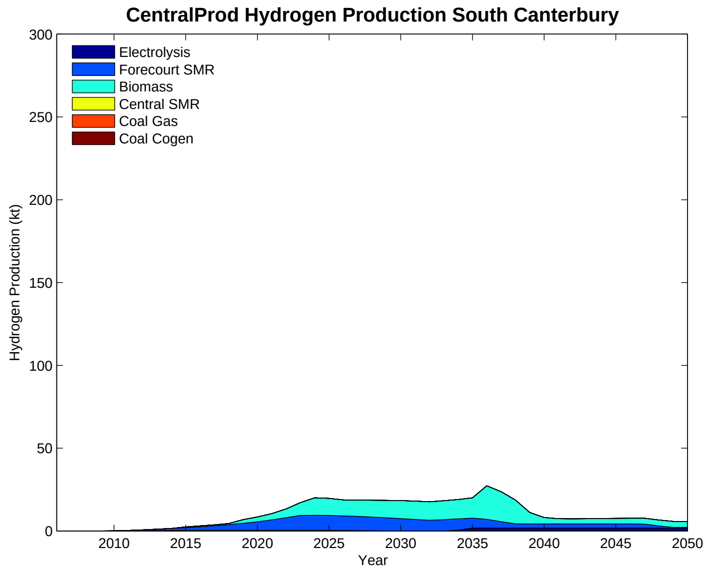


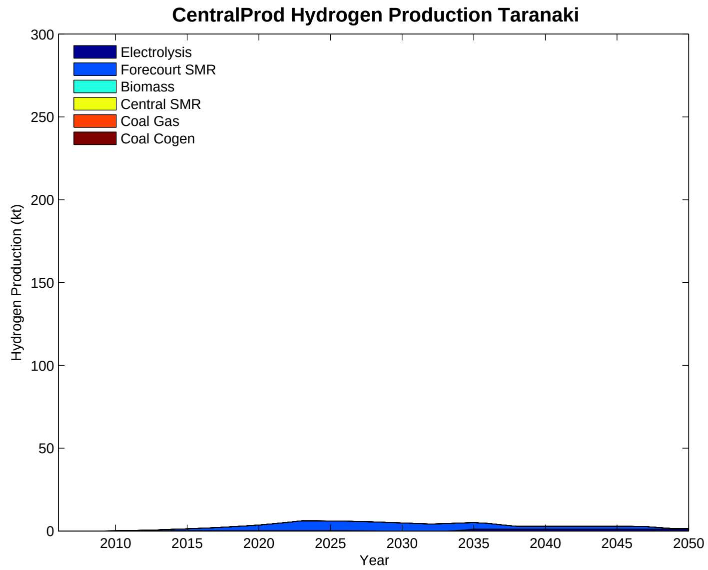

CentralProd Hydrogen Production Hawke's Bay
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

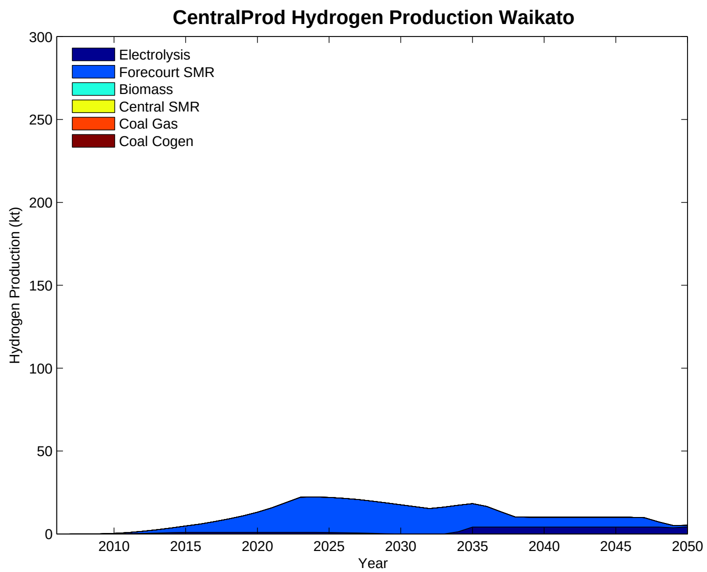

CentralProd Hydrogen Production Nelson−Marlborough
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

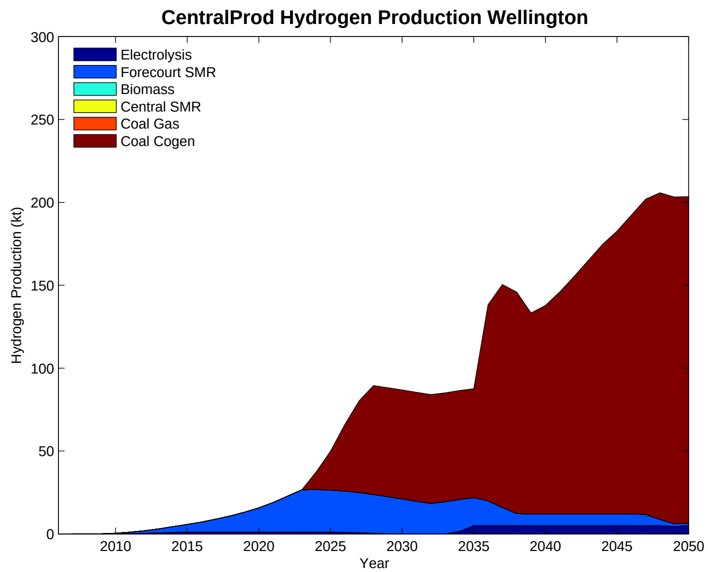

CentralProd Hydrogen Production Northland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


CentralProd Hydrogen Production Otago−Southland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


CentralProd Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


CentralProd Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


CentralProd Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year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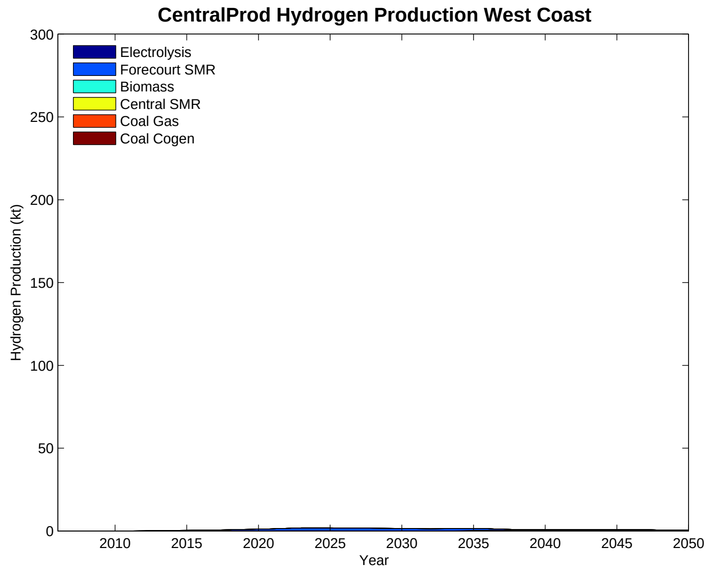
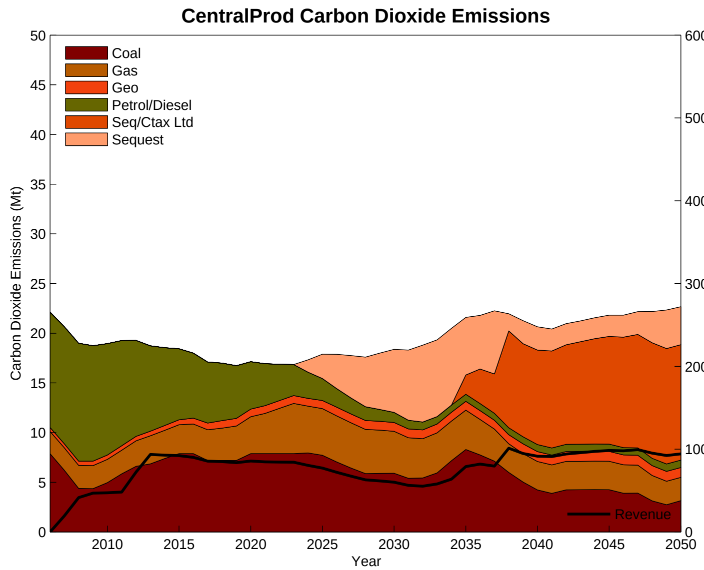
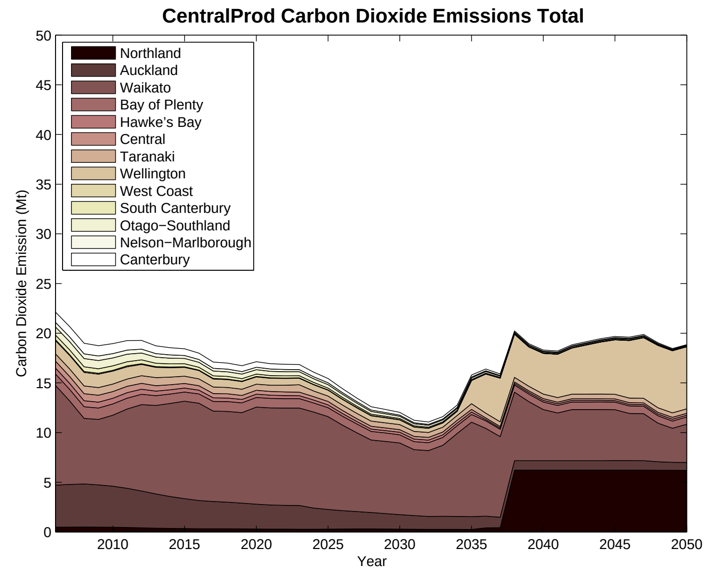
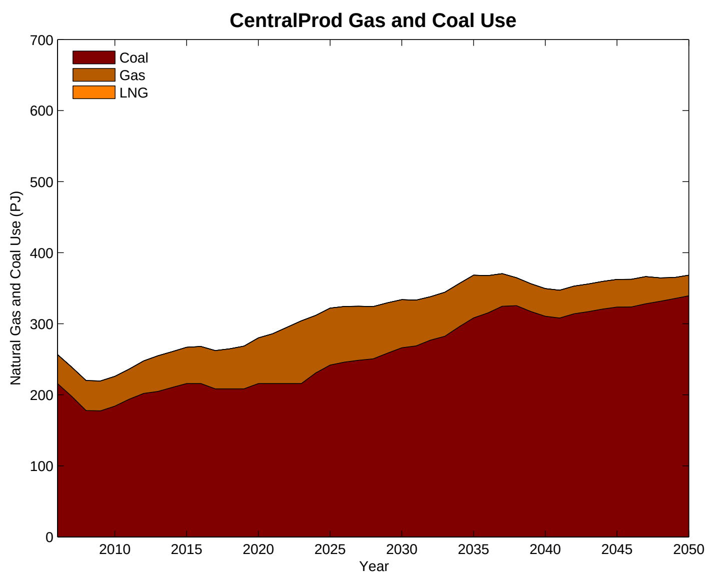
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year

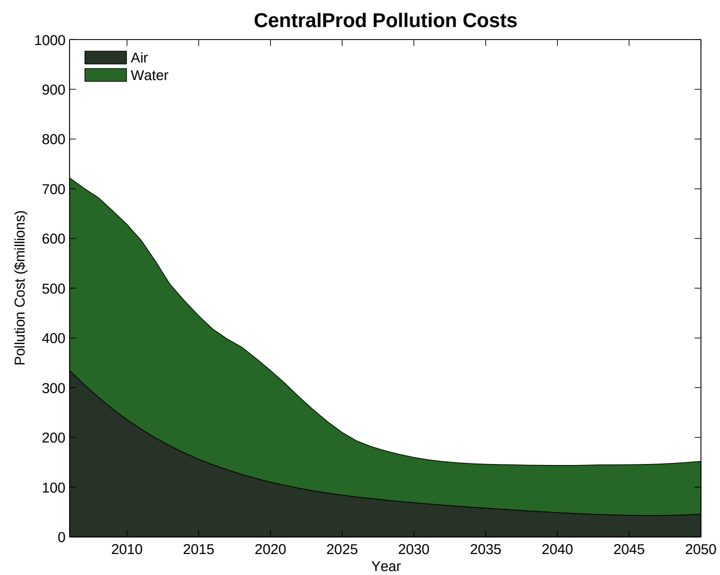

CentralProd Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
300
250
200
150
100
50
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

Carbon Emissions - Energy Consumption and Pollution

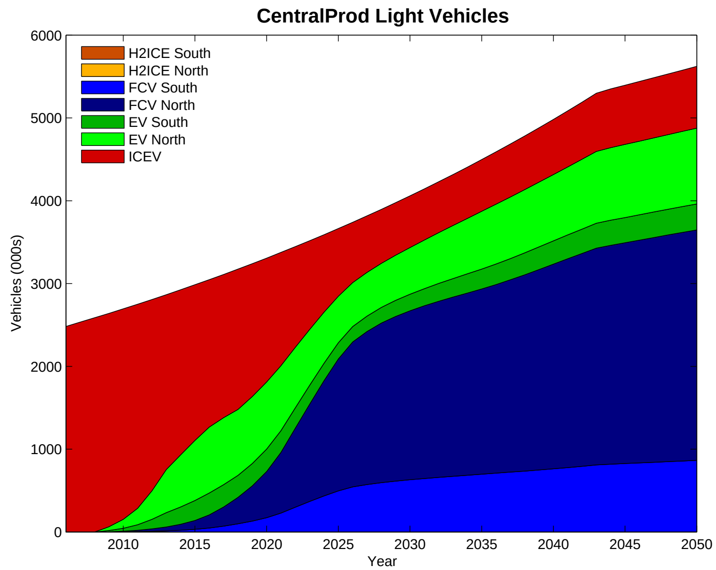


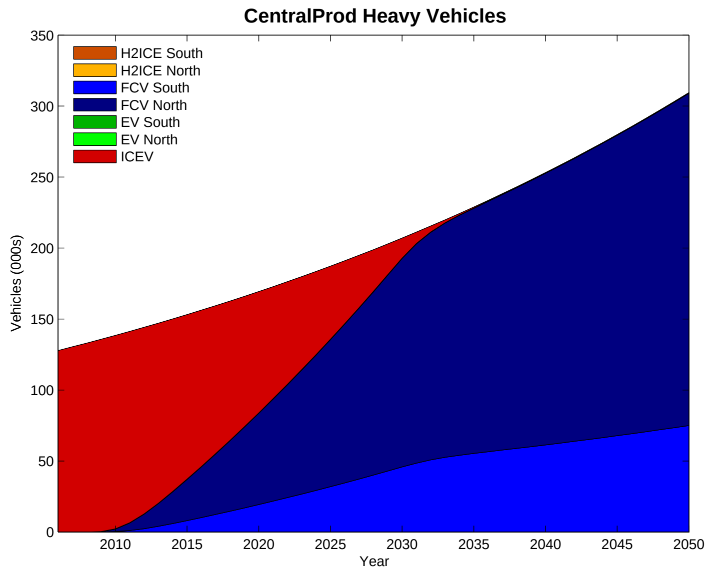


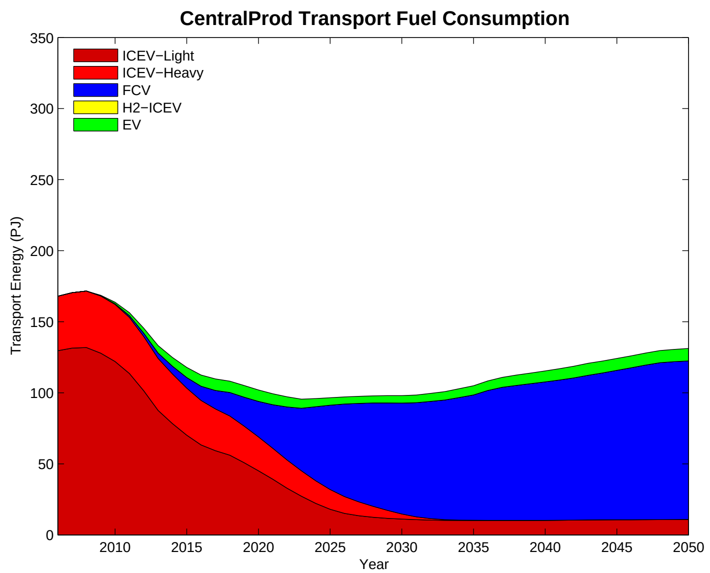




Transportation Sector





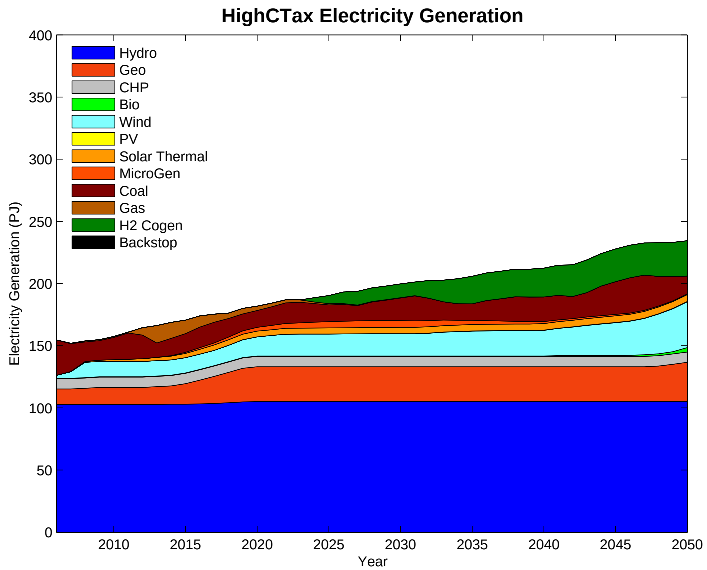


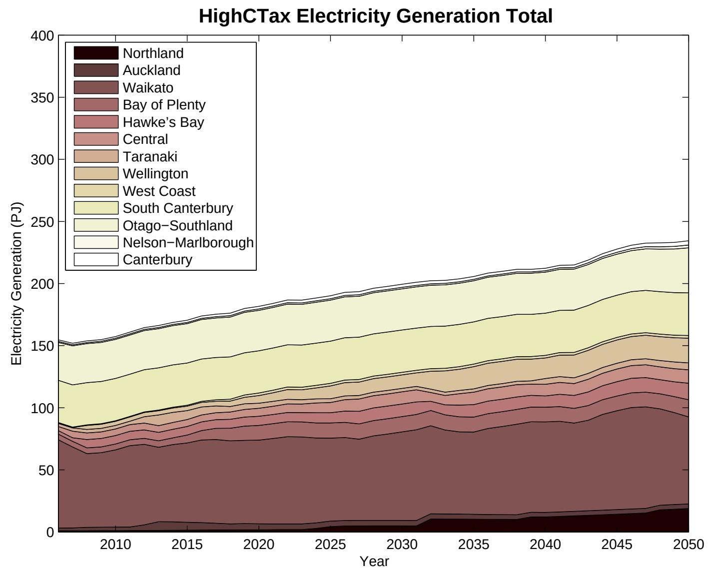
35 Scenario: High CO_2 Tax

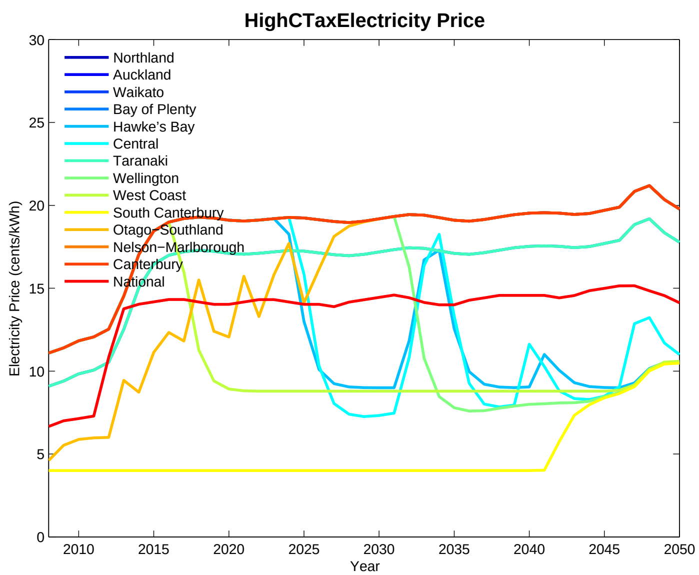
Key results for this scenario are:

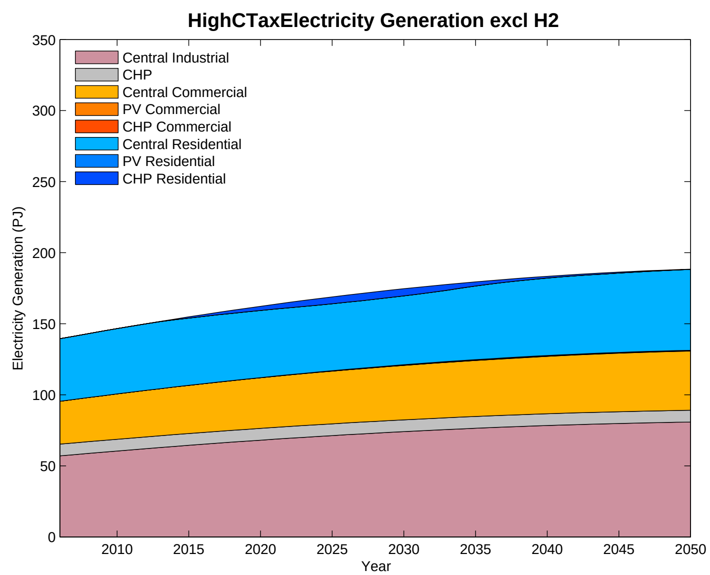
- National wholesale electricity price rises to 13.7 c/kWh in 2013 due the impact of the carbon tax. After 2020 it averages 14.4 c/kWh to 2050.
- CO_2 emissions in 2050 are 24% below 2006 levels with 14% of total emissions being sequestered. A further 43% of emissions are captured during generation but emitted either due to a lack of sequestration capacity or a preference to pay the carbon tax.
- The proportion of renewable electricity generation is 86% in 2025 and 82% in 2050.
- Hydrogen generation in 2050 consists of 12% electrolysis, 14% forecourt SMR, 29% biomass gasification, and 45% coal cogeneration.
- Primary fossil fuel energy use increases by 26% between 2006 and 2050.
- 65% of the light vehicle fleet switches to HFCVs by 2050 with 22% switching to EVs. EVs and HFCVs begin to enter the market in significant numbers after 2012 and 2020 respectively, when growth is rapid due to the reducing capital cost of fuel cells and increasing oil price.
- The heavy vehicle fleet is entirely HFCVs by 2040.
- Air and water pollution costs reduce from $722 million in 2006 to $259 million in 2050.

The National Electricity Market

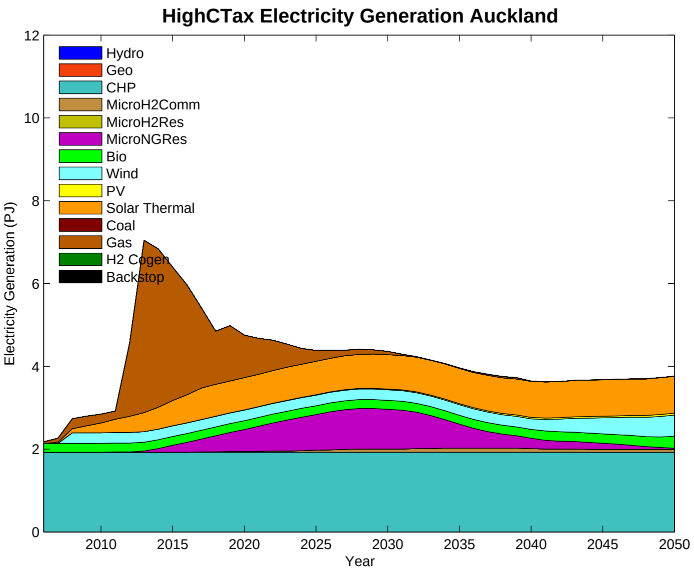


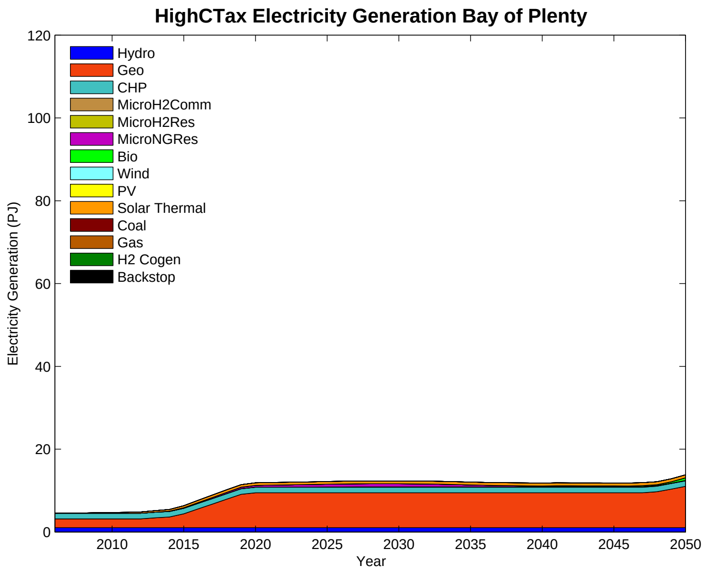


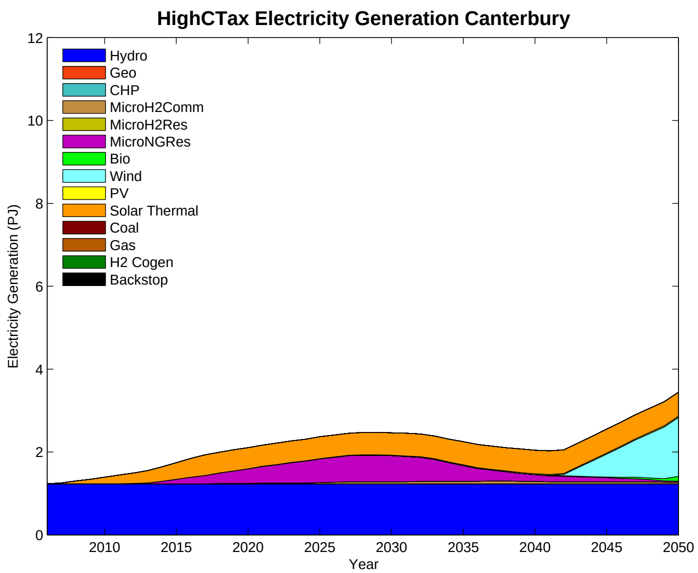


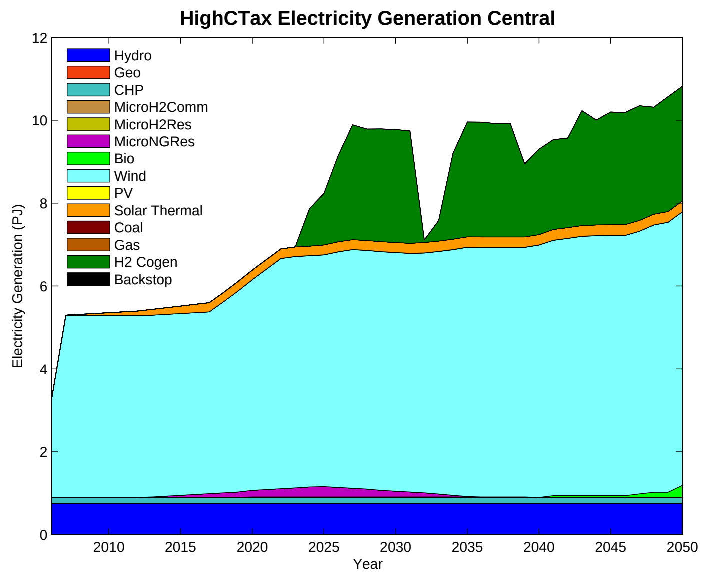


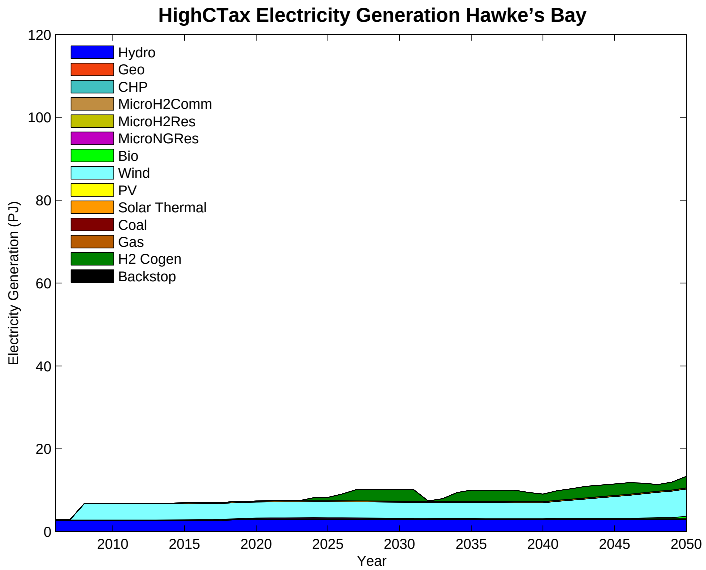
Regional Electricity Markets










HighCTax Electricity Generation Hawke's Bay
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
20
40
60
80
100
120
2010
2015
2020
2025
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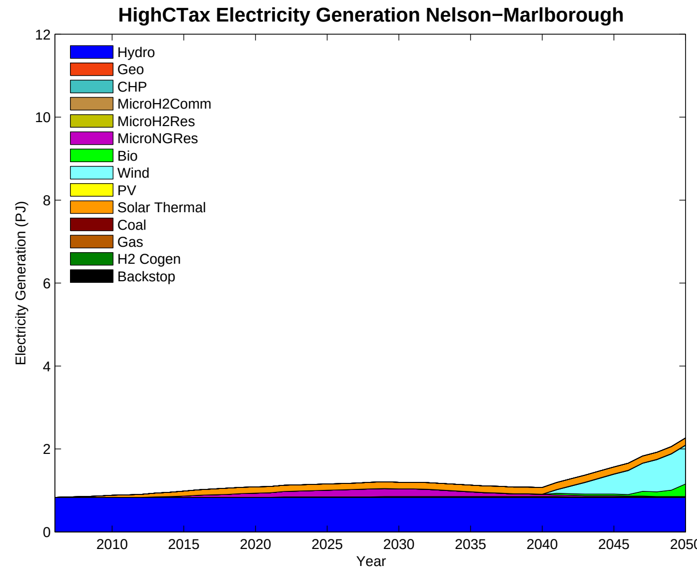
2035
2040
2045
2050
Year


HighCTax Electricity Generation Nelson−Marlborough
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
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6
8
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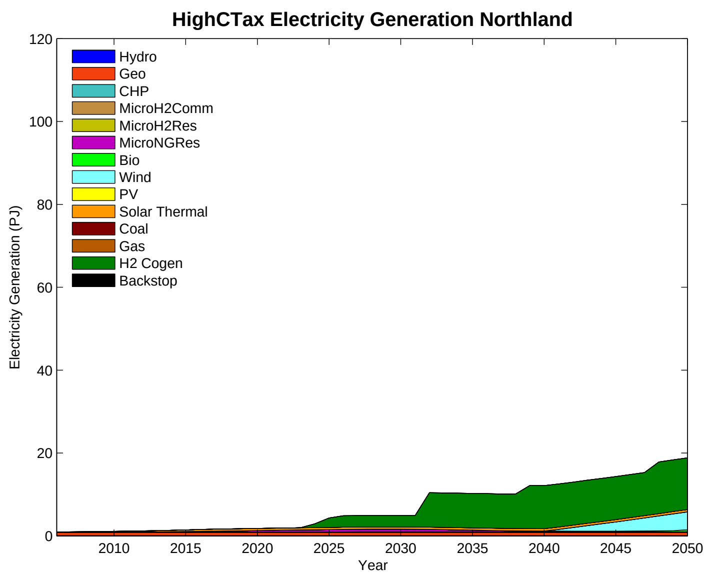
12
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year


HighCTax Electricity Generation Northland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
0
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80
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120
2010
2015
2020
2025
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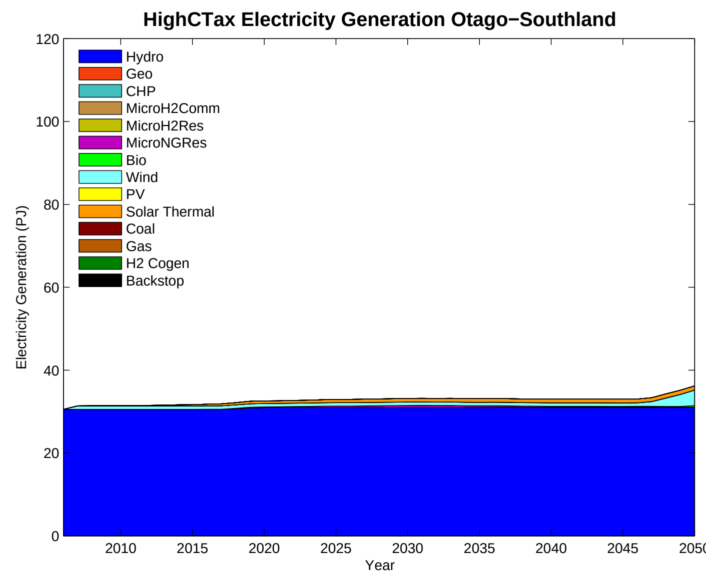
2050
Year


HighCTax Electricity Generation Otago−Southland
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop
Electricity Generation (PJ)
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2015
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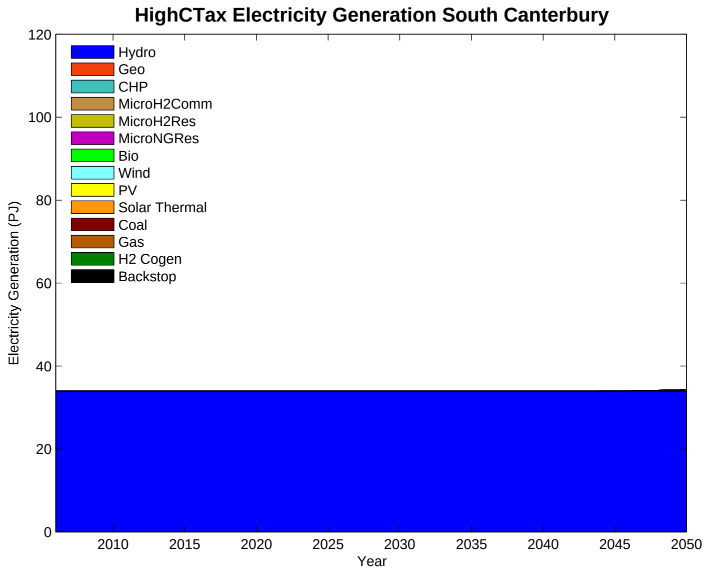
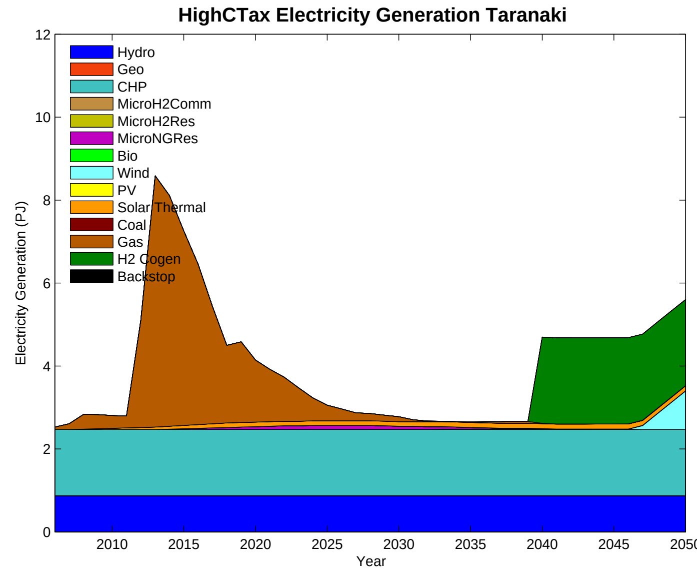
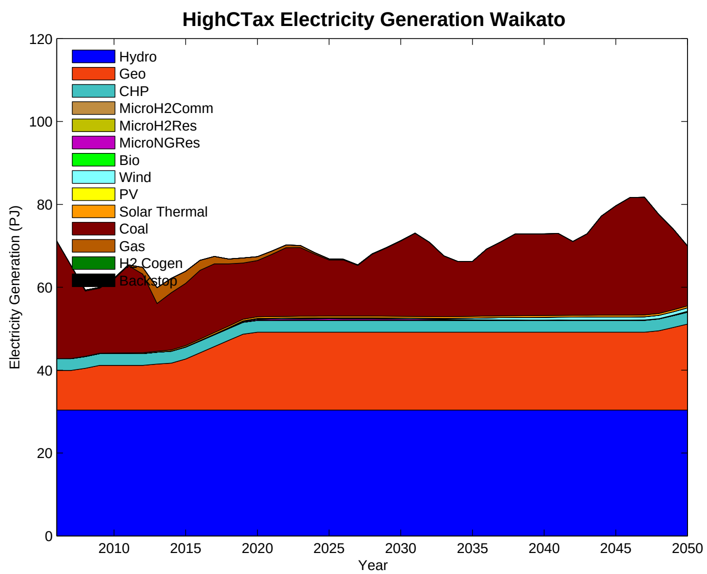
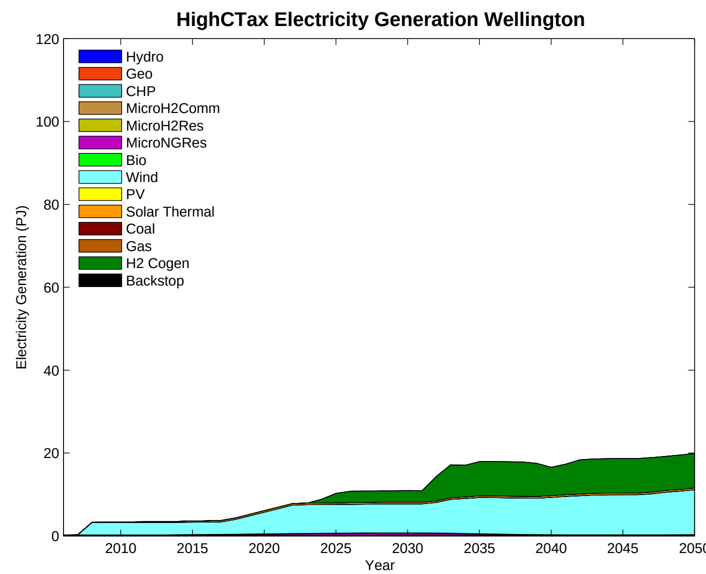
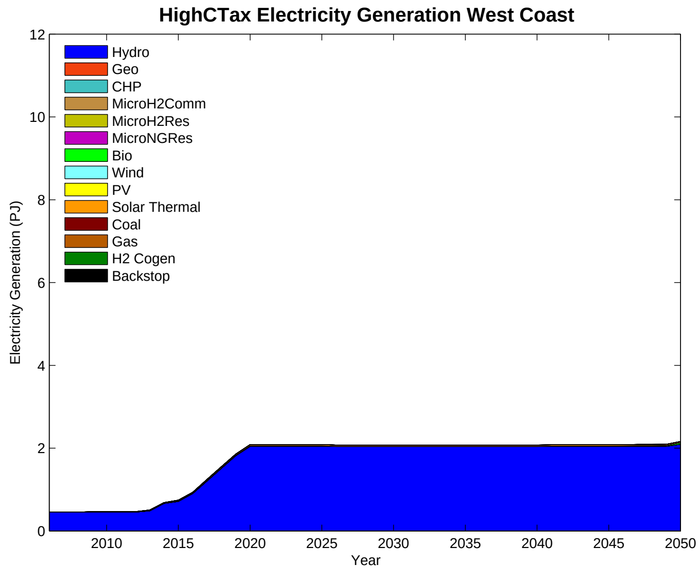
2050
Year


HighCTax Electricity Generation South Canterbury
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


HighCTax Electricity Generation Taranaki
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


HighCTax Electricity Generation Waikato
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


HighCTax Electricity Generation Wellington
Electricity Generation (PJ)
Year
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop


HighCTax Electricity Generation West Coast
Electricity Generation (PJ)
Year
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2010
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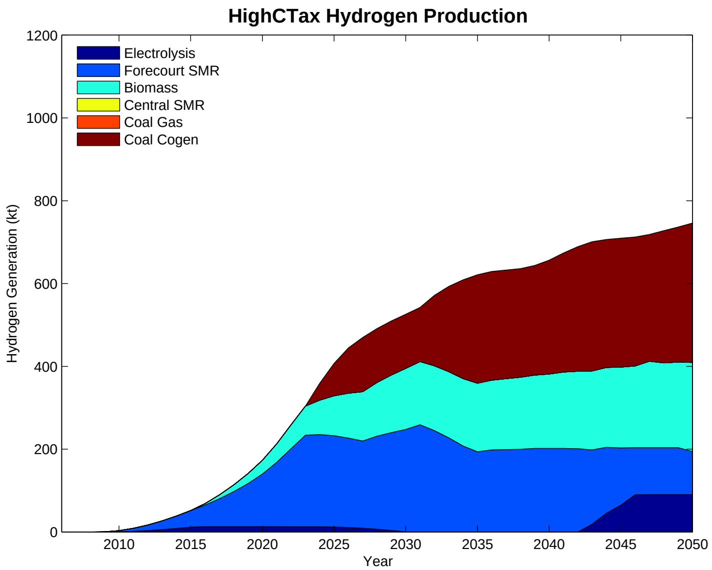
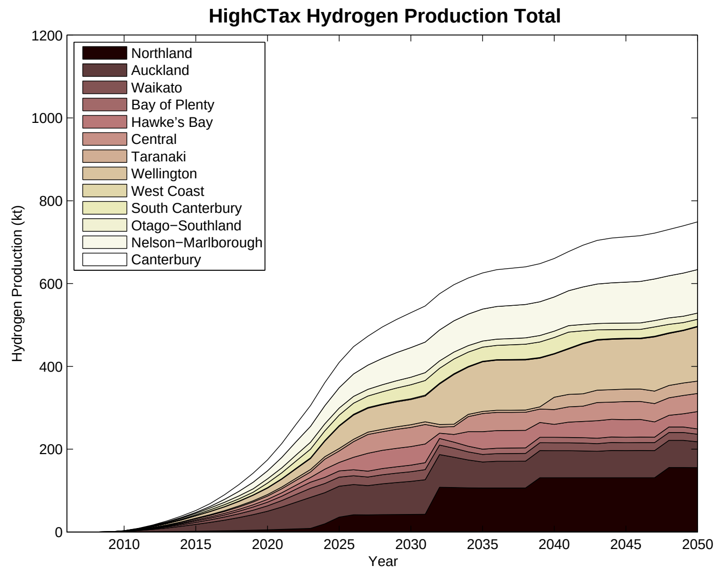
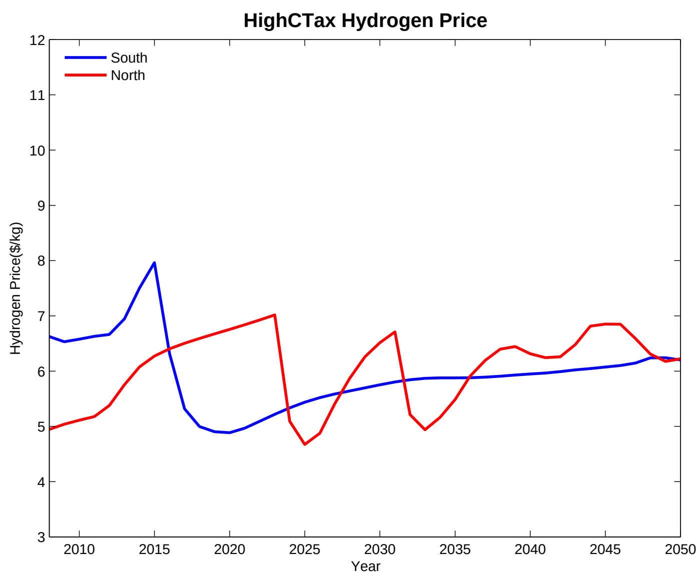
2020
2025
2030
2035
2040
2045
2050
Hydro
Geo
CHP
MicroH2Comm
MicroH2Res
MicroNGRes
Bio
Wind
PV
Solar Thermal
Coal
Gas
H2 Cogen
Backstop

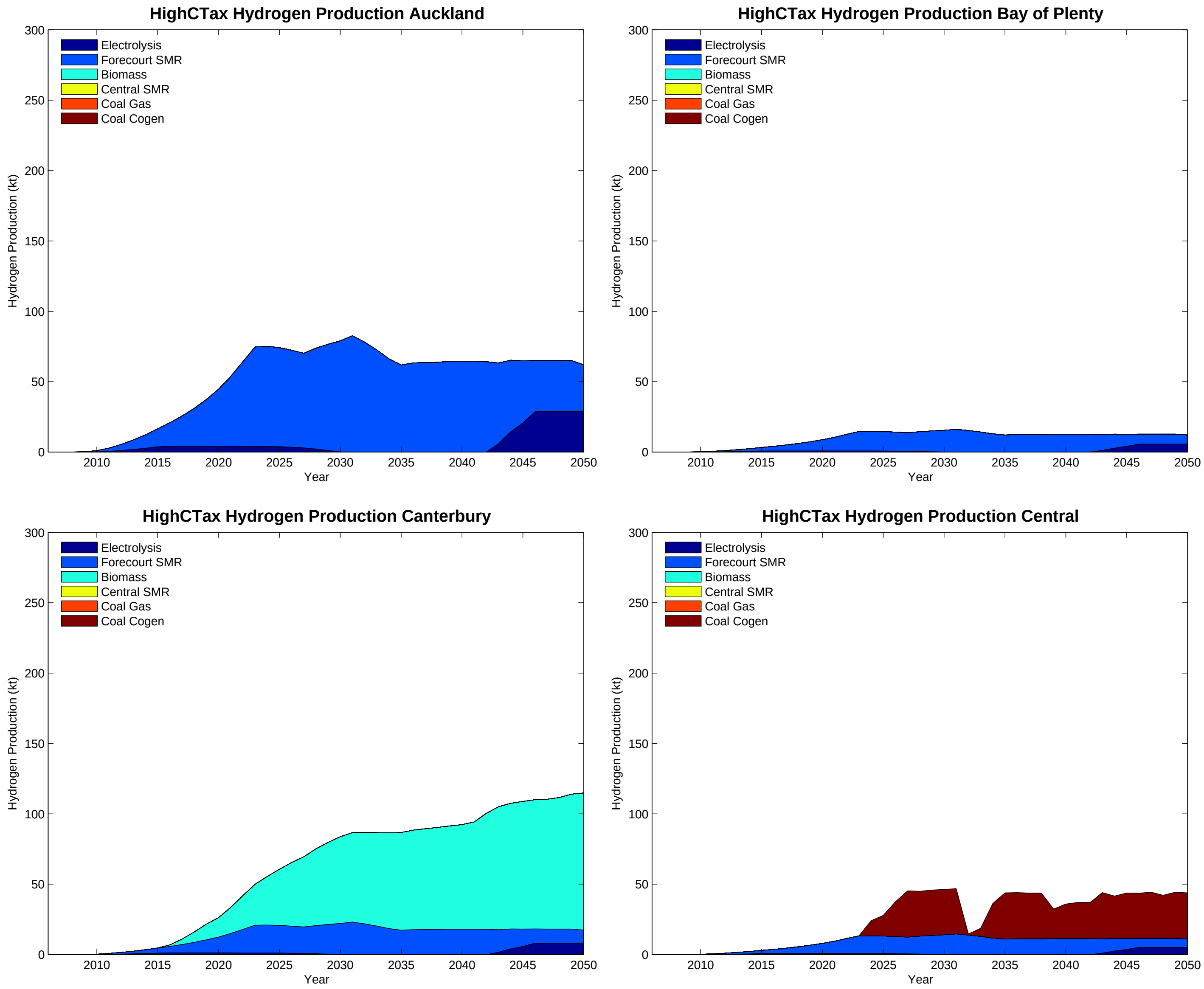
The National Hydrogen Market

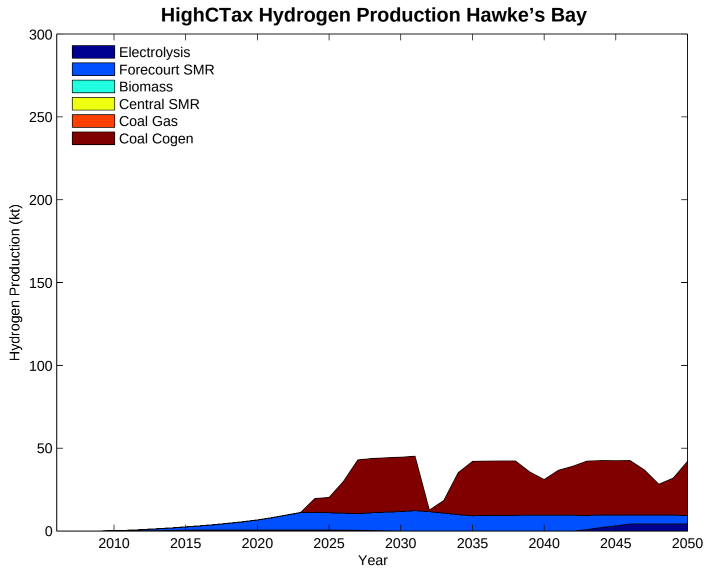


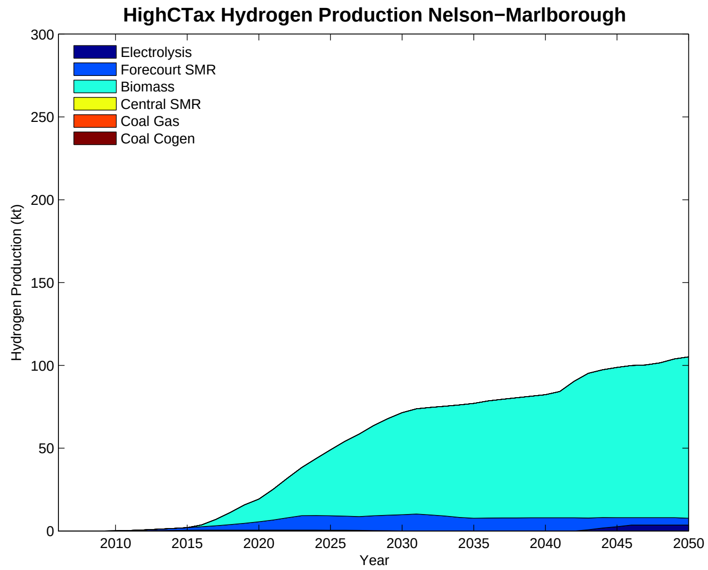


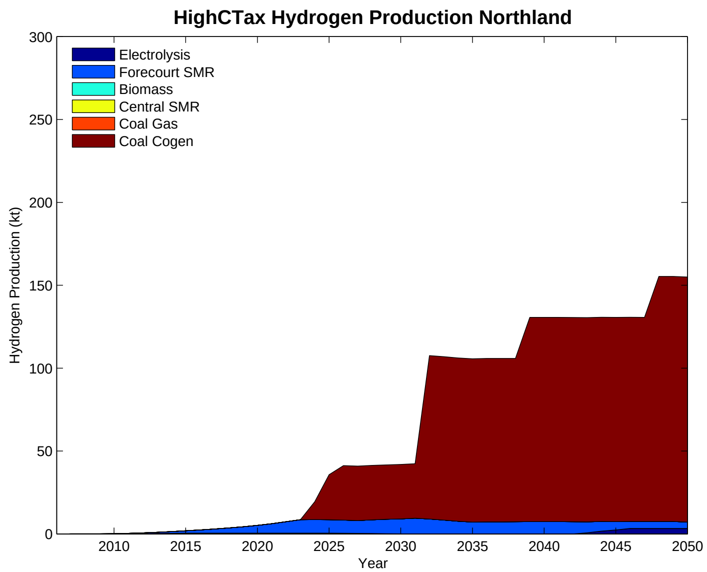


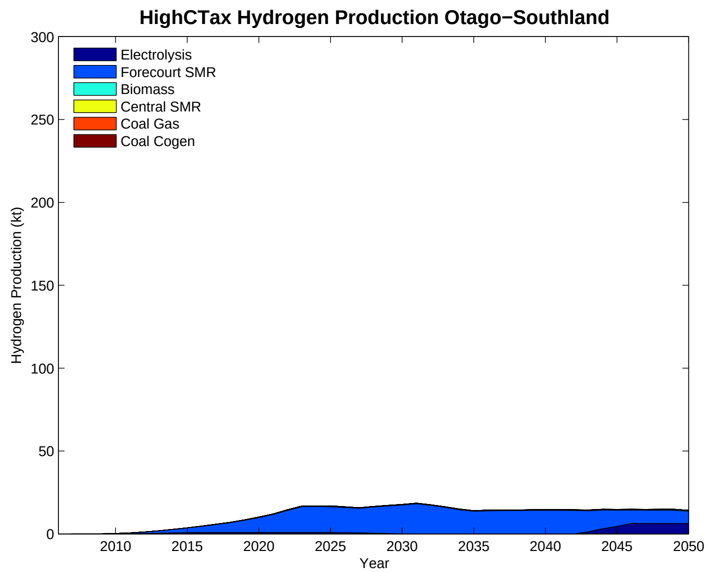
Regional Hydrogen Markets

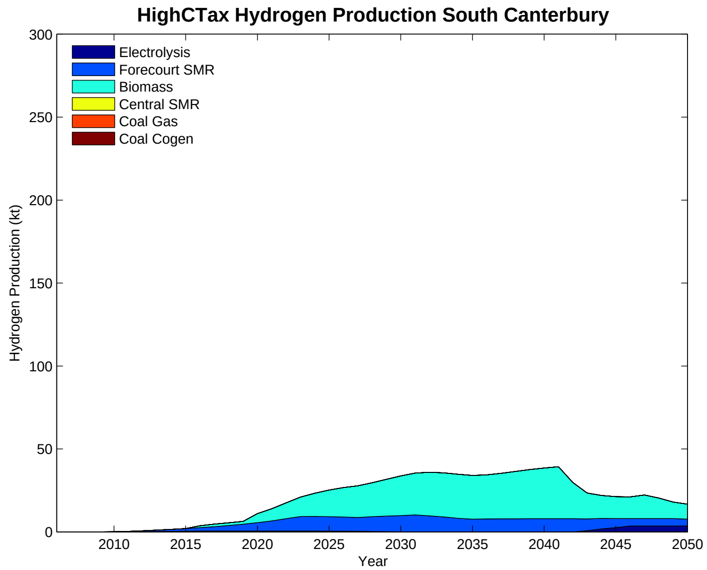



HighCTax Hydrogen Production Hawke's Bay
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


HighCTax Hydrogen Production Nelson−Marlborough
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


HighCTax Hydrogen Production Northland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


HighCTax Hydrogen Production Otago−Southland
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
Year


HighCTax Hydrogen Production South Canterbury
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
0
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2010
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2020
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2045
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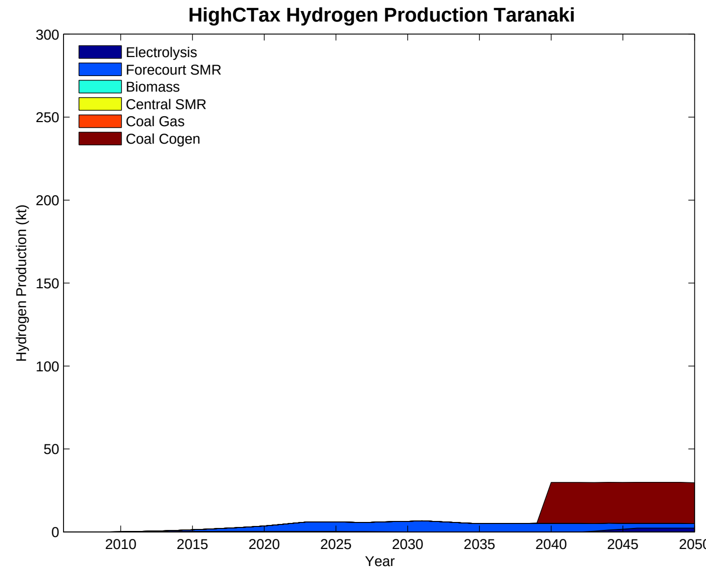
Year


HighCTax Hydrogen Production Taranaki
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
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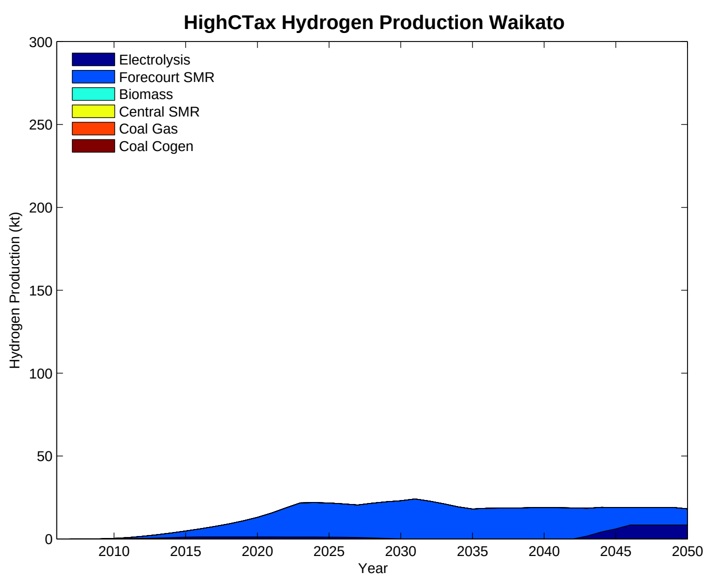
Year


HighCTax Hydrogen Production Waikato
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
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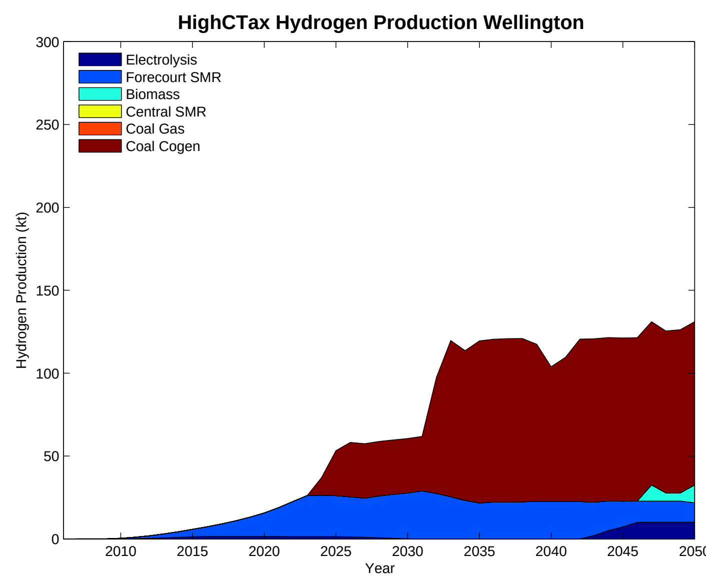
2050
Year


HighCTax Hydrogen Production Wellington
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
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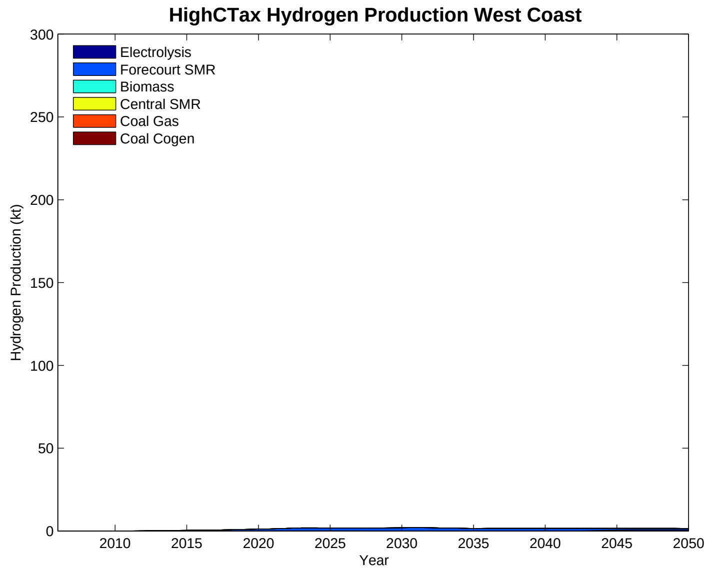
2045
2050
Year


HighCTax Hydrogen Production West Coast
Electrolysis
Forecourt SMR
Biomass
Central SMR
Coal Gas
Coal Cogen
Hydrogen Production (kt)
300
250
200
150
100
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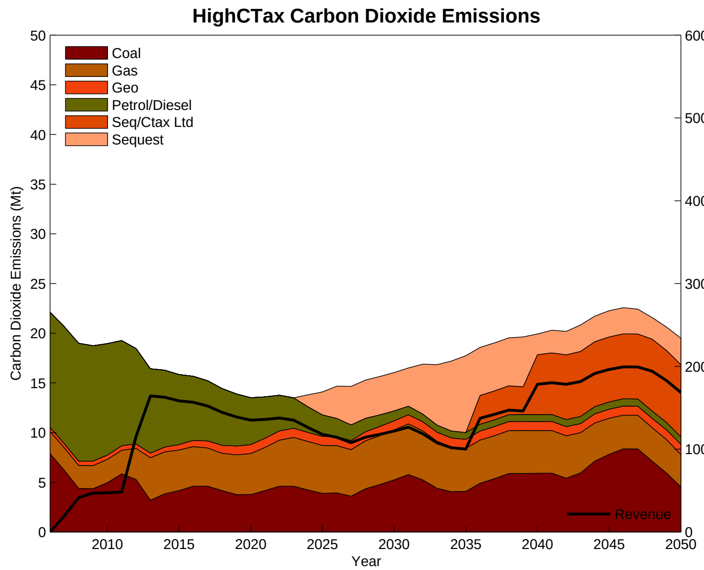
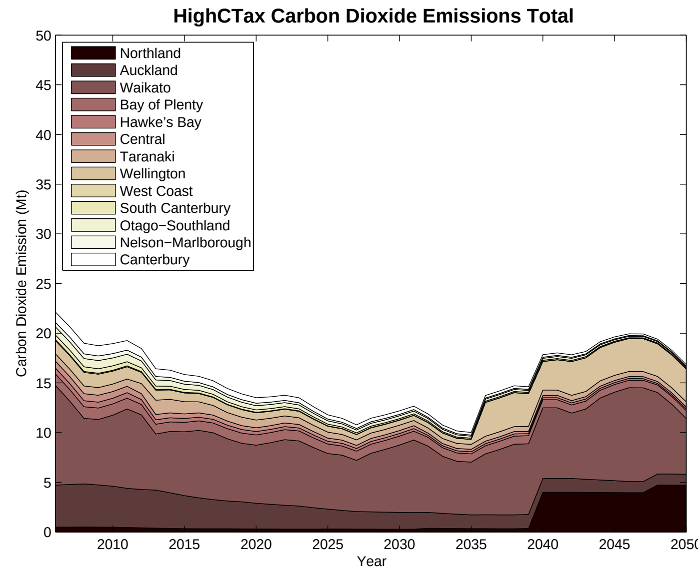
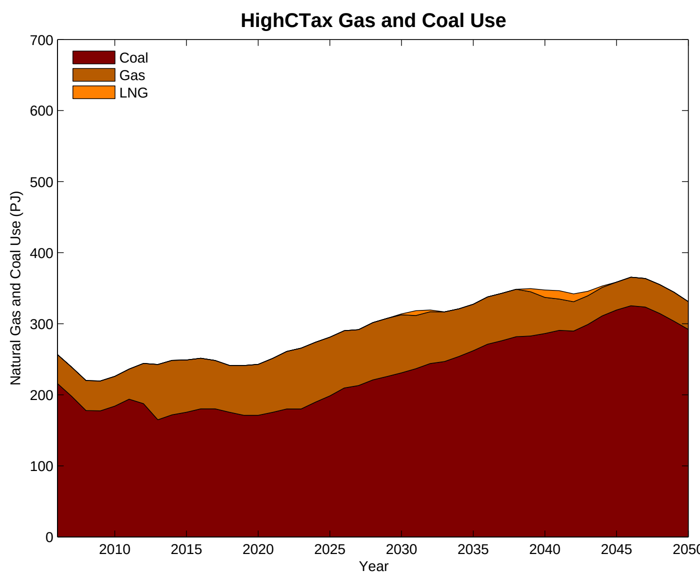
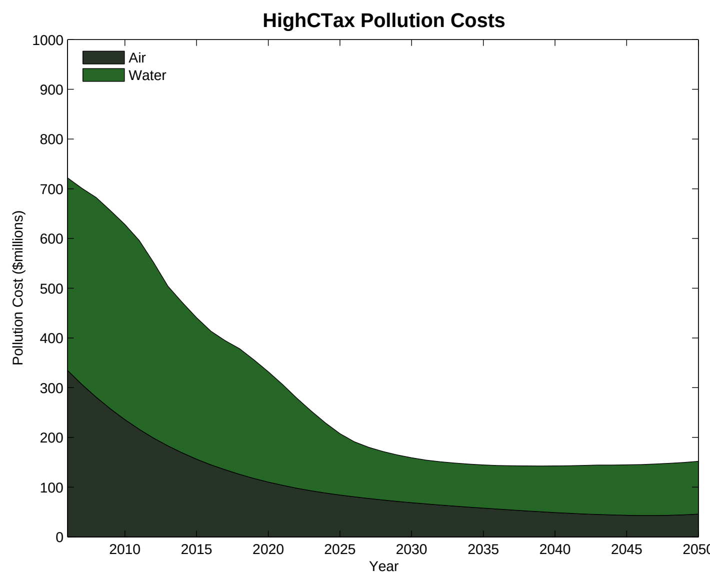
0
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year

Carbon Emissions - Energy Consumption and Pollution

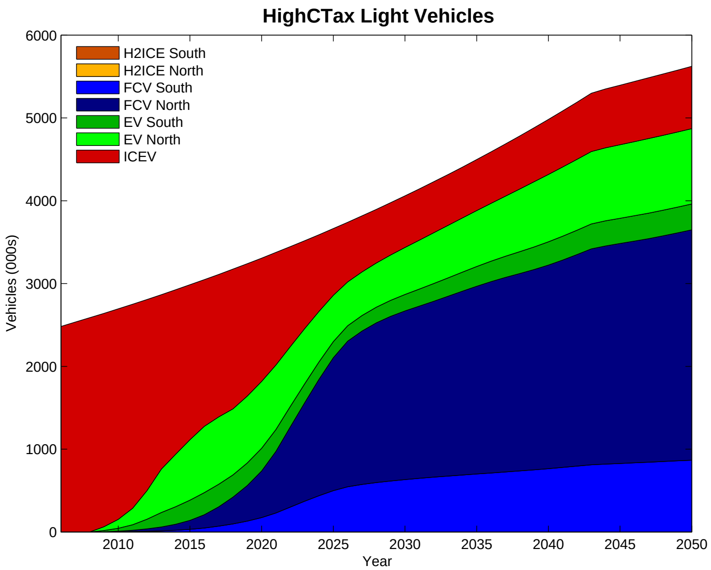


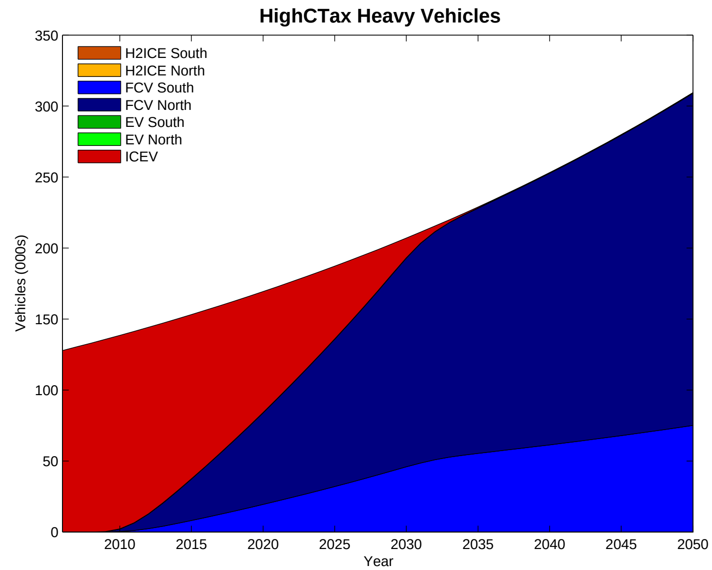


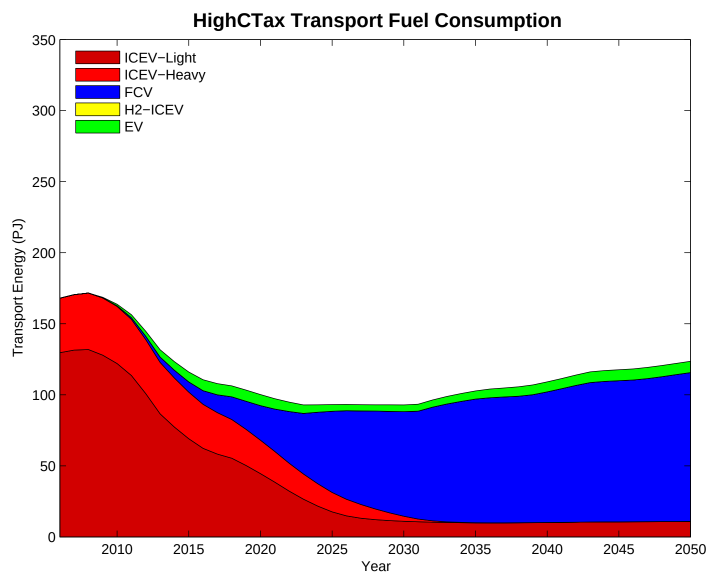




Transportation Sector







Appendix I: Forecourt H_2 Production

FORECOURT SMR	variables		totals		
Capital Costs				$1,160,000	$US
General Facilities & permitting		25%	of unit cost	$290,000.00	$US
Eng. Startup & contingencies		10%	of unit cost	$116,000.00	$US
Contingencies		10%	of unit cost	$116,000.00	$US
Working Capital, Land & Misc		7%	of unit cost	$81,200.00	$US
				$1,763,200.00	$US
Unit Costs					
Variable Non-fuel O&M @		0.50%	/yr of capital	$ 8,816.00	$US
Electricity @	$	0.05	US c/kwh	$ 35,321.68	$US
Natural Gas @	$	5.00	$/GJ	$ 194,661.81	$US
Fixed Operating Cost @		3%	/yr of capital	$ 52,896.00	$US
Capital Charges @		18%	/yr of capital	$ 317,376.00	$US
Annual Fueling Station Cost				$ 609,071.50	$US
Unitized Fueling Station Cost			/kg	$ 2.64	$US
Unitized Fueling Station Cost			/kg	$ 5.29	$NZ
Total Non-Fuel SMR Station Cost			/kg	$ 1.65	$US
Total Non-Fuel SMR Station Cost			/kg	**$ 3.29**	$NZ

BOLD VALUES USED IN STELLA			
SMR			
H2 PROD	Capacity Factor	70%	
	Availability Factor	98%	
	Max H2 Production	920	kg/d
	Max Yearly Production	**329,084**	kg/y
	Capital Planning Yearly H2 Production	**230,359**	kg/y
	Natural Gas Need	**0.169007491**	GJ/kg H2
	SMR Electricity Need	**3.07**	kwh/kg H2
	Yearly Natural Gas Usage	38932.36273	GJ
	Yearly Electricity Usage	706433.6533	kwh

FORECOURT ELECTROLYSIS	variables	totals			
Capital Costs			$	2,100,000.00	$US
General Facilities & permitting	25%	of unit cost	$	525,000.00	$US
Eng. Startup & contingencies	10%	of unit cost	$	210,000.00	$US
Contingencies	10%	of unit cost	$	210,000.00	$US
Working Capital, Land & Misc	7%	of unit cost	$	147,000.00	$US
			$	3,192,000.00	$US
Unit Costs					
Variable Non-fuel O&M @	0.50%	/yr of capital	$	15,960.00	
Electricity @	$ 0.05	US c/kwh	$	721,123.20	
Fixed Operating Cost @	3%	/yr of capital	$	95,760.00	
Capital Charges @	18%	/yr of capital	$	574,560.00	
Annual Fueling Station Cost			$	1,407,403.20	
Unitized Fueling Station Cost		/kg	$	3.36	$US
Unitized Fueling Station Cost		/kg	$	6.73	$NZ
Total Non-Fuel Electrolysis Station Cost		/kg	$	1.64	$US
Total Non-Fuel Electrolysis Station Cost		/kg	**$**	**3.28**	$NZ
H2 PROD	Capacity Factor			70%	
	Availability Factor			98%	
	Max H2 Production			542	nm3/h
	Density of H2			0.0899	kg/Nm3
	Max Yearly Production			**418301.2478**	kg/y
	Capital Planning Yearly H2 Production			**292810.8735**	kg/y
	Electricity Need			2.40	MW
	Electricity Need			**49.25522003**	kwh/kg
	Yearly Electricity Usage			14422464	kwh

Appendix II: Centralised H_2 Production

COAL GASIFICATION: 75 tonne plant on the North Island

Central Plant	variables	final costs	totals					
			Vehicles Supported		135,506			
H2 Production		75,000	kg H2/d	load factor	90%			
Hourly		3,125	kg/h	coal-H2 efficiency	64%	LHV		
MJ		443,750	MJ H2/h		61%	HHV		
MBTU		421	M Btu/hr H2					
Hourly Coal Consumption		685.83	M Btu/hr H2 HHV					
Energy Density of Coal		28.00	MBTU/tonne LHV	29.3	MBTU/tonne HHV			
Daily Coal Consumption		561775.25	kg/d					
Air Separation Unit O2		1.10	metric tons O2/ton dry coal					
ASU O2 Consumption		617.95	metric tons/d O2					
ASU Power		0.40	kWh/kg O2					
ASU Electricity Consumption		247181.11	kWh/d					
Unitized ASU Electricity Consumption		3.295748153	kWh/kg					
H2 Liquefaction		11	kwh/kg					
Misc. Electricity Consumption		1.2	kwh/kg					
CO2 Emissions		20.43733048	kg CO2/kg H2					
Unitized Carbon Tax @	$ 25.00	$0.51	NZ$					
Dispenser Statistics		4,000.00	kg/h					
Dispensers Needed		1						
Coal Sulphur Properties		1%	Sulphur					
Liquid Storage		12	hours					
Liquid Storage		37,500	kg liq H2	3.733	gal phy liq H2/kg H2			
Liquid Storage		139,988	gal phy liq H2					

	unit cost basis at		cost/size	unit cost basis at				
Capital Costs	*100,000*	*kg/d H2*	*factors*	*75,000*	*kg/d H2*	*cost for one plant*		
Coal handling & prep	$ 20.00	/kg/d coal	75%	$ 21.49	/kg/d coal	$ 12,073,335.91	spare unit	
Texaco coal gasifiers	$ 25.00	/kg/d coal	85%	$ 26.10	/kg/d coal	$ 17,596,434.18		20%
Air seperation unit (ASU)	$ 28.00	/kg/d oxygen	75%	$ 30.09	/kg/d oxygen	$ 18,592,937.31		
CO shift, cool & cleanup	$ 20.00	/kg/d CO2	75%	$ 21.49	/kg/d CO2	$ 32,942,011.23		
Sulfur recovery	$ 400.00	/kg/d sulfur	80%	$ 423.69	/kg/d sulfur	$ 2,380,182.97		
H2 Cryo Liquefaction	$ 700.00	/kg/d H2	75%	$ 752.20	/kg/d H2	$ 56,414,921.42		

Liquid H2 storage	$	5.00	/gal phy vol	70%	$	5.45	/gal phy vol	$	763,028.72	
Liquid H2 dispenser	$	100,000.00	/dispenser	100%	$	100,000.00	/dispenser	$	100,000.00	
							Total Process Units	$	140,862,851.74	
			General Facilities & permitting			30%	of process units		$42,258,855.52	
			Eng. Startup & contingencies			15%	of process units		$21,129,427.76	
			Contingencies			10%	of process units		$14,086,285.17	
			Working Capital, Land & Misc			7%	of process units		$9,860,399.62	
							Capital Costs		$228,197,819.81	per plant

Rate of return:			16%	
Lifetime			30	years
Capital Recover Factor			16.18857%	/yr of capital
Capital Cost			$228,197,820	US$
Annualized Recover Cost			$36,941,960.00	US$
Unitized Recovery Cost			$1.50	US$
Unitized Recovery Cost			$3.00	NZ$
Electric Power				
Unitized Electricity Consumption			15.49574815	kwh/kg H2
Unitized Electricity Cost @	$	0.10	$1.55	NZ$
Coal				
Daily Coal Consumption			561775.25	kg/d
Energy Conversion			1.054615	GJ/MMBtu
Daily Coal Consumption			17358.97864	GJ/d HHV
Unitized Coal Consumption			0.231453049	GJ Coal HHV/kg H2
Unitized Coal Cost @$3.5/GJ			$0.81	NZ$
Operating Costs				
Variable Non-fuel O&M @		1%	$0.19	NZ$
Fixed Operating Cost @		5%	$0.93	NZ$
Total Cost, Non-distributed:			$6.98	NZ$

Transport

Truck Delivery Distance	200	km
Truck Utilization	80%	

Capital Costs					
Tank & undercarrage		$5,378,906	US$		
Cab		$949,219	US$		
Total Capital Costs		$6,328,125	US$		
Annualized Recover Cost @	18%	$1,139,062.50	US$		
Unitized Recover Cost		$0.04630	US$		
Unitized Recover Cost		$0.0926	NZ$		
Variable Operating Cost					
Labor		$1,478,250.00	NZ$		
Fuel		$633,902.34	NZ$		
Variable Non-fuel O&M @	1%	$126,562.50	NZ$		
Total Variable Operating Costs		$2,238,714.84	NZ$		
Unitized Variable Operating Costs		$0.0910	NZ$		
Fixed Operating Cost @	5%	$632,812.50	NZ$		
Unitized Fixed Costs		$0.0257	NZ$		
Total Transport Costs		$0.2093			
Total Cost, Non-dispensed		$7.19			
Assumptions					
Truck Tank	$450,000	per tank	US$		
Undercarraige	$60,000	per trailer	US$		
Cab	$90,000	per cab	US$		
Truck boil-off rate	0.30%	per day			
Truck capacity	4,000	kg/tank			
Fuel economy	2.53	km/L		6	mpg
Average speed	50	km/h			
Load/unload time	4	hr/trip			
Truck availability	24	hr/day			
Hour/driver	12	hr/driver			
Driver wage & benefits	$20.00	per hr	NZ$		
Fuel price	$0.65	per l diesel	NZ$		
Truck Requirement Calcs					
Trips per year	6,159	trips		17	trips per day
Total Distance	2,463,750	km/yr			

Time for each trip	8.0	hours					
Trip length	12.0	hours, with reloading					
Delivered product	24,600,544	kg/year	Trip Delivered Product				
Total delivery time	73912.5	hr/yr		3994	kg per Trip		
Total driving time	49275	hr/yr					
Total load/unload time	24637.5	hr/yr					
Truck availability	7008	hr/yr					
Truck requirement	11	trucks					
Driver time	3120	hr/yr					
Drivers required	24	persons					
Fuel Usage	975,234.38	L/yr					
FCV							
FCV	55	mpg		88	km per gallon		
FCV	16000	km/year		181.8181818	gallons per year or kg per year per vehicle		

Filling Station

Fueling Capacity	2000	kg/d/station	load factor	70%	Vehicles Supported		2,811
Average Consumption	1400	kg/d/station					
Total Stations	48	stations	17	hour operation			
Tanker every	2.852857143	days					
Liquid H2 storage	14,900	gals (enough to store approx 4,000kg H2)					
Number of Dispensers	6						
Average Dispensing Rate	82.35	kg/hr					
Surge Rate	3	times average					
Surge Rate Per Dispenser	41.18	kg/hr	(Max 48)				
H2 Buffer Storage, enough fo	2	hours at surge rate					
H2 Buffer Storage	494.12	kg		3,952.94	gal physical vol at 400atm		
Liquid H2 Pump	0.8	kw/kg/hr					
Electric Power	1120.00	kwh/d					
	Unit cost basis at		*cost/size*	*Unit cost at*			
Capital Costs	*1000*	*kg/d H2*	*factors*	*2000*	*kg/d H2*		*cost US$*
Liquid H2 pump/vaporizer	$250	/kg/d H2	70%	$203.06	/kg/d H2		$406,126.20

Liquid H2 storage	$10	/gal phy vol		70%	$8.12	/gal phy vol	$121,025.61	
H2 buffer storage	$100	/gal phy vol		80%	$87.06	/gal phy vol	$344,123.52	
Liquid H2 dispenser	$15,000	/dispenser		100%	$15,000.00	/dispenser	$90,000.00	
				Station Cost			$961,275.32	
	General Facilities & permitting				25%	of unit cost	$240,318.83	
	Eng. Startup & contingencies				10%	of unit cost	$96,127.53	
	Contingencies				10%	of unit cost	$96,127.53	
	Working Capital, Land & Misc				7%	of unit cost	$67,289.27	
						Capital Costs	$1,461,138.49	per station
			Costs (US$)					
			Variable Non-fuel O&M @			0.50%	$7,305.69	per year
			Electricity @			$ 0.05	$20,440.00	per year
			Fixed Operating Cost @			3%	$43,834.15	per year
			Capital Charges @			18%	$263,004.93	per year
			Fueling Station Cost				$334,584.78	per year
			Unitized Fueling Station Cost				$0.65	US$
			Unitized Fueling Station Cost				$1.31	NZ$
			Total Cost				$8.50	NZ$

CARBON	COAL Carbon	BITUMINOUS		
CO2 Emissions	205.3	lb/MMBTU HHV	2204.62	lbs/tonne
	0.093122624	tonnes/MMBTU		
	0.088300114	tonnes/GJ HHV		
	0.02043733	tonnes/kg H2		
		GWP		
	0.7	t CH4/PJ	23	t CO2/t Methane
	1.5	t N2O/PJ	296	t CO2/t N2O
	0.000003726	tonnes CO2 due to CH4		
	0.000102765	tonnes due to N2O		
Total CO2 Equiv.	0.020543822			
Total Carbon Tax	$ 0.514	per kg H2 product		

BIOMASS GASIFICATION: 125 tonne plant on the South Island

Central Plant	variables	final costs	totals	Vehicles Supported	225,844	
H2 Production		125,000	kg H2/d	load factor	90%	
Hourly		5,208	kg/h	coal-H2 efficiency	60.82%	LHV
MJ		739,583	MJ H2/h		57%	HHV
MBTU		701	M Btu/hr H2			
Hourly Biomass Consumption		1222.09	M Btu/hr H2 HHV		1,295	M Btu/hr H2 HHV
Energy Density of Biomass		17.64	MBTU/bone dry tonne HHV		8000.000	BTU/bone dry lb HHV
Daily Biomass Consumption		1762576.02	kg/d		2204.62	pounds/tonne
Air Separation Unit O2		0.80	metric tons O2/ton dry feed			
ASU O2 Consumption		1410.06	metric tons/d O2			
ASU Power		0.40	kWh/kg O2			
ASU Electricity Consumption		564024.33	kWh/d			
Unitized ASU Electricity Consumption		4.512194619	kWh/kg			
H2 Liquefaction		11	kwh/kg			
Misc. Electricity Consumption		1.2	kwh/kg			
CO2 Emissions		17.5	kg CO2/kg H2			
Unitized Carbon Tax @	$ 25.00	$0.00	NZ$			
Dispenser Statistics		4,000.00	kg/h			
Dispensers Needed		2				
Liquid Storage		12	hours			
Liquid Storage		62,500	kg liq H2	3.733	gal phy liq H2/kg H2	
Liquid Storage		233,313	gal phy liq H2			

	unit cost basis at		*cost/size*	*unit cost basis at*			
Capital Costs	*100,000*	*kg/d H2*	*factors*	*125,000*	*kg/d H2*	*cost for one plant*	
Biomass handling & prep	$ 25.00	/kg/d dry bio	75%	$ 23.64	/kg/d dry bio	$ 41,673,537.10	spare unit
Shell gasifiers	$ 20.00	/kg/d dry bio	80%	$ 19.13	/kg/d dry bio	$ 40,455,455.66	20%
Air seperation unit (ASU)	$ 27.00	/kg/d oxygen	75%	$ 25.54	/kg/d oxygen	$ 36,005,936.06	
CO shift, cool & cleanup	$ 15.00	/kg/d CO2	75%	$ 14.19	/kg/d CO2	$ 31,032,146.55	
H2 Cryo Liquefaction	$ 700.00	/kg/d H2	75%	$ 662.02	/kg/d H2	$ 82,752,390.79	
Liquid H2 storage	$ 5.00	/gal phy vol	70%	$ 4.68	/gal phy vol	$ 1,091,025.77	
Liquid H2 dispenser	$ 100,000.00	/dispenser	100%	$ 100,000.00	/dispenser	$ 200,000.00	

				Total Process Units	$ 233,210,491.92
	General Facilities & permitting		30%	of process units	$69,963,147.57
	Eng. Startup & contingencies		15%	of process units	$34,981,573.79
	Contingencies		10%	of process units	$23,321,049.19
	Working Capital, Land & Misc		7%	of process units	$16,324,734.43
				Capital Costs	$377,800,996.90 per plant

Rate of return:		16%	
Lifetime		30	years
Capital Recover Factor		16.18857%	/yr of capital
Capital Cost		$377,800,997	US$
Annualized Recover Cost		$61,160,572.55	US$
Unitized Recovery Cost		$1.49	US$
Unitized Recovery Cost		$2.98	NZ$
Electric Power			
Unitized Electricity Consumption		16.71219462	kwh/kg H2
Unitized Electricity Cost @	$ 0.10	$1.67	NZ$
Coal			
Daily Biomass Consumption		1762576.02	kg/d
Energy Conversion		1.054615	GJ/MMBtu
Daily Biomass Consumption		32784.27107	GJ/d HHV
Unitized Bone Dry Biomass Consumption		0.262274169	GJ Bone Dry Biomass HHV/kg H2
Unitized Biomass Cost @	$ 3.00	$0.79	NZ$
Operating Costs			
Variable Non-fuel O&M @	1%	$0.18	NZ$
Fixed Operating Cost @	5%	$0.92	NZ$
Total Cost, Non-distributed:		$6.54	NZ$

Transport

Truck Delivery Distance	450	km
Truck Utilization	80%	
Capital Costs		
Tank & undercarrage	$16,435,547	US$

Cab		$2,900,391	US$
Total Capital Costs		$19,335,938	US$
Annualized Recover Cost @	18%	$3,480,468.75	US$
Unitized Recover Cost		$0.08499	US$
Unitized Recover Cost		$0.1700	NZ$
Variable Operating Cost			
Labor		$4,516,875.00	NZ$
Fuel		$2,377,133.79	NZ$
Variable Non-fuel O&M @	1%	$386,718.75	NZ$
Total Variable Operating Costs		$7,280,727.54	NZ$
Unitized Variable Operating Costs		$0.1778	NZ$
Fixed Operating Cost @	5%	$1,933,593.75	NZ$
Unitized Fixed Costs		$0.0472	NZ$
Total Transport Costs		$0.3950	
Total Cost, Non-dispensed		$6.94	

Assumptions

Truck Tank	$450,000	per tank	US$	
Undercarraige	$60,000	per trailer	US$	
Cab	$90,000	per cab	US$	
Truck boil-off rate	0.30%	per day		
Truck capacity	4,000	kg/tank		
Fuel economy	2.53	km/L		6 mpg
Average speed	50	km/h		
Load/unload time	4	hr/trip		
Truck availability	24	hr/day		
Hour/driver	12	hr/driver		
Driver wage & benefits	$20.00	per hr	NZ$	
Fuel price	$0.65	per l diesel	NZ$	
Truck Requirement Calcs				
Trips per year	10,266	trips		28 trips per day
Total Distance	9,239,063	km/yr		
Time for each trip	18.0	hours		
Trip length	22.0	hours, with reloading		

Delivered product	40,949,578	kg/year	Trip Delivered Product		
Total delivery time	225843.75	hr/yr		3989	kg per Trip
Total driving time	184781.25	hr/yr			
Total load/unload time	41062.5	hr/yr			
Truck availability	7008	hr/yr			
Truck requirement	32	trucks			
Driver time	3120	hr/yr			
Drivers required	72	persons			
Fuel Usage	3,657,128.91	L/yr			
FCV					
FCV					
FCV					

Filling Station

Fueling Capacity	2000	kg/d/station	load factor	70%	Vehicles Supported		2,811
Average Consumption	1400	kg/d/station					
Total Stations	80	stations	17	hour operation			
Tanker every	2.849285714	days					
Liquid H2 storage	14,900	gals (enough to store approx 4,000kg H2)					
Number of Dispensers	6						
Average Dispensing Rate	82.35	kg/hr					
Surge Rate	3	times average					
Surge Rate Per Dispenser	41.18	kg/hr	(Max 48)				
H2 Buffer Storage, enough f	2	hours at surge rate					
H2 Buffer Storage	494.12	kg	3,952.94	gal physical vol at 400atm			
Liquid H2 Pump	0.8	kw/kg/hr					
Electric Power	1120.00	kwh/d					

	Unit cost basis at		*cost/size*		*Unit cost at*		
Capital Costs	*1000*	*kg/d H2*	*factors*		*2000*	*kg/d H2*	*cost*
Liquid H2 pump/vaporizer	$250	/kg/d H2		70%	$203.06	/kg/d H2	$406,126.20
Liquid H2 storage	$10	/gal phy vol		70%	$8.12	/gal phy vol	$121,025.61
H2 buffer storage	$100	/gal phy vol		80%	$87.06	/gal phy vol	$344,123.52

Liquid H2 dispenser	$15,000 /dispenser		100%	$15,000.00 /dispenser			$90,000.00	
			Station Cost				$961,275.32	
	General Facilities & permitting			25%	of unit cost		$240,318.83	
	Eng. Startup & contingencies			10%	of unit cost		$96,127.53	
	Contingencies			10%	of unit cost		$96,127.53	
	Working Capital, Land & Misc			7%	of unit cost		$67,289.27	
			Capital Costs (US$)				$1,461,138.49	per station
		Costs (US$)						
		Variable Non-fuel O&M @				0.50%	$7,305.69	per year
		Electricity @				$ 0.05	$20,440.00	per year
		Fixed Operating Cost @				3%	$43,834.15	per year
		Capital Charges @				18%	$263,004.93	per year
		Fueling Station Cost					$334,584.78	per year
		Unitized Fueling Station Cost					$0.65	US$
		Unitized Fueling Station Cost					$1.31	NZ$
		Total Cost					$8.25	NZ$

NATURAL GAS REFORMING: 250 tonne plant on the North Island

Central Plant	**variables**	**final costs**	**totals**	Vehicles Suppor	451,688		
H2 Production		250,000	kg H2/d	load factor		90%	
Hourly		10,417	kg/h	gas-H2 efficiency		76.2%	LHV
SCF		105,842,506	SCF/d	0.002362	kg/scf	68.9%	HHV
MJ		1,479,167	MJ H2/h				
Hourly Natural Gas Consumption		2,147,305	MJ/h HHV Gas	0.904	LHV/HHV Gas		
Daily Natural Gas Consumption		51535.32	GJ/d HHV				
H2 Liquefaction		11	kwh/kg				
Misc. Electricity Consumption		0.2	kwh/kg				
CO2 Emissions		10.76	kg CO2/kg H2				
Unitized Carbon Tax @	$ 25.00	$0.27	NZ$				
Dispenser Statistics		4,000.00	kg/h				
Dispensers Needed		3					
Liquid Storage		12	hours				
Liquid Storage		125,000	kg liq H2	3.733	gal phy liq H2/kg H2		
Liquid Storage		466,625	gal phy liq H2				
	unit cost basis at		*cost/size*	*unit cost basis at*			
Capital Costs	*100,000*	*kg/d H2*	*factors*	*250,000*	*kg/d H2*	*cost for one plant*	
SMR	$ 0.75	/scf/d H2	70%	$ 0.57	/scf/d H2	$ 60,303,063.58	
H2 Cryo Liquefaction	$ 700.00	/kg/d H2	75%	$ 556.69	/kg/d H2	$ 139,172,377.53	
Liquid H2 storage	$ 5.00	/gal phy vol	70%	$ 3.80	/gal phy vol	$ 1,772,376.59	
Liquid H2 dispenser	$ 100,000.00	/dispenser	100%	$ 100,000.00	/dispenser	$ 300,000.00	
					Total Process Units	$ 201,547,817.70	
		General Facilities & permitting		20%	of process units	$40,309,563.54	
		Eng. Startup & contingencies		15%	of process units	$30,232,172.66	
		Contingencies		10%	of process units	$20,154,781.77	
		Working Capital, Land & Misc		7%	of process units	$14,108,347.24	
					Capital Costs	$306,352,682.91	per plant
Rate of return:		16%					
Lifetime		30	years				
Capital Recover Factor		16.18857%	/yr of capital				

Capital Cost		$306,352,683	US$
Annualized Recover Cost		$49,594,113.42	US$
Unitized Recovery Cost		$0.60	US$
Unitized Recovery Cost		$1.21	NZ$
Electric Power			
Unitized Electricity Consumption		11.2	kwh/kg H2
Unitized Electricity Cost @	$ 0.10	$1.12	NZ$
Coal			
Daily Natural Gas Consumption		51535.32	GJ/d HHV
Unitized Gas Consumption		0.206141268	GJ Coal HHV/kg H2
Unitized Gas Cost @	$ 9.00	$ 1.86	NZ$
Operating Costs			
Variable Non-fuel O&M @	1%	$0.07	NZ$
Fixed Operating Cost @	5%	$0.37	NZ$
Total Cost, Non-distributed:		$4.90	NZ$

Transport

Truck Delivery Distance		200	km
Truck Utilization		80%	
Capital Costs			
Tank & undercarrage		$17,929,688	US$
Cab		$3,164,063	US$
Total Capital Costs		$21,093,750	US$
Annualized Recover Cost @	18%	$3,796,875.00	US$
Unitized Recover Cost		$0.04630	US$
Unitized Recover Cost		$0.0926	NZ$
Variable Operating Cost			
Labor		$4,927,500.00	NZ$
Fuel		$2,113,007.81	NZ$
Variable Non-fuel O&M @	1%	$421,875.00	NZ$
Total Variable Operating Costs		$7,462,382.81	NZ$
Unitized Variable Operating Costs		$0.0910	NZ$

Fixed Operating Cost @	5%	$2,109,375.00	NZ$	
Unitized Fixed Costs		$0.0257	NZ$	
Total Transport Costs		$450.0000		
Total Cost, Non-dispensed		$5.11		
Assumptions				
Truck Tank	$450,000	per tank	US$	
Undercarraige	$60,000	per trailer	US$	
Cab	$90,000	per cab	US$	
Truck boil-off rate	0.30%	per day		
Truck capacity	4,000	kg/tank		
Fuel economy	2.53	km/L		6 mpg
Average speed	50	km/h		
Load/unload time	4	hr/trip		
Truck availability	24	hr/day		
Hour/driver	12	hr/driver		
Driver wage & benefits	$20.00	per hr	NZ$	
Fuel price	$0.65	per l diesel	NZ$	
Truck Requirement Calcs				
Trips per year	20,531	trips		56 trips per day
Total Distance	8,212,500	km/yr		
Time for each trip	8.0	hours		
Trip length	12.0	hours, with reloading		
Delivered product	82,001,813	kg/year	Trip Delivered Product	
Total delivery time	246375	hr/yr		3994 kg per Trip
Total driving time	164250	hr/yr		
Total load/unload time	82125	hr/yr		
Truck availability	7008	hr/yr		
Truck requirement	35	trucks		
Driver time	3120	hr/yr		
Drivers required	79	persons		
Fuel Usage	3,250,781.25	L/yr		
FCV				
FCV	55	mpg		88 km per gallon

FCV	16000	km/year		181.8181818	gallons per year or kg per year per vehicle		

Filling Station

Fueling Capacity	2000	kg/d/station	load factor	70%	Vehicles Supported	2,811	
Average Consumption	1400	kg/d/station					
Total Stations	160	stations	17	hour operation			
Tanker every	2.852857143	days					
Liquid H2 storage	14,900	gals (enough to store approx 4,000kg H2)					
Number of Dispensers	6						
Average Dispensing Rate	82.35	kg/hr					
Surge Rate	3	times average					
Surge Rate Per Dispenser	41.18	kg/hr	(Max 48)				
H2 Buffer Storage, enough fo	2	hours at surge rate					
H2 Buffer Storage	494.12	kg	3,952.94	gal physical vol at 400atm			
Liquid H2 Pump	0.8	kw/kg/hr					
Electric Power	1120.00	kwh/d					

	Unit cost basis at		*cost/size*		*Unit cost at*		
Capital Costs	*1000*	*kg/d H2*	*factors*		*2000*	*kg/d H2*	*cost*
Liquid H2 pump/vaporizer	$250	/kg/d H2		70%	$203.06	/kg/d H2	$406,126.20
Liquid H2 storage	$10	/gal phy vol		70%	$8.12	/gal phy vol	$121,025.61
H2 buffer storage	$100	/gal phy vol		80%	$87.06	/gal phy vol	$344,123.52
Liquid H2 dispenser	$15,000	/dispenser		100%	$15,000.00	/dispenser	$90,000.00
					Station Cost		$961,275.32
	General Facilities & permitting				25%	of unit cost	$240,318.83
	Eng. Startup & contingencies				10%	of unit cost	$96,127.53
	Contingencies				10%	of unit cost	$96,127.53
	Working Capital, Land & Misc				7%	of unit cost	$67,289.27
						Capital Costs	$1,461,138.49 per station US$

Costs (US$)			
Variable Non-fuel O&M @	0.50%	$7,305.69	per year
Electricity @	$ 0.05	$20,440.00	per year
Fixed Operating Cost @	3%	$43,834.15	per year

Capital Charges @	18%	$263,004.93	per year
Fueling Station Cost		$334,584.78	per year
Unitized Fueling Station Cost		$0.65	US$
Unitized Fueling Station Cost		$1.31	NZ$
Total Cost		$6.42	NZ$

CARBON

CO2 Emissions	52.1	kt Co2/pj		
	0.0521	tonnes/GJ HHV		
	0.01073996	tonnes/kg H2		
			GWP	
	2.7	t CH4/PJ	23	t CO2/t Methane
	0.09	t N2O/PJ	296	t CO2/t N2O
	0.000012801	tonnes CO2 due to CH4		
	0.000005492	tonnes due to N2O		
Total CO2 Equiv.	0.010758253	tonnes/kg H2		

COAL COGEN WITH SEQUESTRATION: 400 tonne plant on the South Island

Central Plant	**variables**	**final costs**	**totals**	**guess**	Vehicles Supported	722,700	
H2 Production		169,348,010.16	SCF/d	0.002362	kg/scf		
H2 Production		400,000	kg H2/d	load factor		90%	
Hourly		16,667	kg/h	coal-H2 efficiency		65.24%	HHV
MJ		2,366,667	MJ H2/h HHV	2366.666667	GJ H2 HHV/h		
Hourly Coal Consumption		5855.50	GJ Coal HHV/h				
Energy Density of Coal		27	MJ HHV/kg				
Daily Coal Consumption		5204891.11	kg/d	907.19	kg/ton	5737.408703	tons per day
Air Separation Unit O2		1.10	metric tons O2/ton dry coal				
ASU O2 Consumption		5725380.23	kg/d O2				
Specific Pre Liquefaction Net Power		1.47	kw/kg/d				
Pre Liquefaction Net Power		587073.10	kw	1453	GJ elec/h		
H2 Liquefaction		11	kwh/kg				
H2 Liquefaction		183,333.33	kw				
Net Power		403,739.77	kw				
CO2 Emissions		31.02249218	kg CO2/kg H2				
CO2 Sequestered @	95%	29.47136757	kg/kg H2				
Sequestration Cost		15	$NZ/tonne CO2 Disposed				
Sequestration Cost		$ 0.44	$NZ/kg H2				
CO2 Emitted		0.0015511	tonne CO2/kg H2				
Unitized Carbon Tax @	$ 25.00	$ 0.04	$NZ/kg H2				
Dispenser Statistics		4,000.00	kg/h				
Dispensers Needed		5					
Coal Sulphur Properties		1%	Sulphur				
Liquid Storage		12	hours				
Liquid Storage		200,000	kg liq H2	3.733	gal phy liq H2/kg H2		
Liquid Storage		746,600	gal phy liq H2				spare unit
	unit cost basis at			*cost/size*	*unit cost basis at*		0%
Capital Costs	*100,000*	*354,300*	*kg/d H2*	*factors*	*400,000*	*kg/d H2*	*cost for one plant*
Coal handling & prep		$ 4.62	/kg/d Coal	75%	$ 4.49	/kg/d Coal	$ 23,347,700.57
Gasification/Quench/Cln		$ 46.79	/kg/d Coal	85%	$ 45.95	/kg/d Coal	$ 239,145,034.56
Air seperation unit (ASU)		$ 19.33	/kg/d Oxygen	75%	$ 18.75	/kg/d Oxygen	$ 107,365,308.91
F-T Synthesis		$ 13.23	/kg/d CO2	75%	$ 12.83	/kg/d CO2	$ 151,293,115.86
Hydrogen Removal		$ 39.51	/kg/d H2	75%	$ 38.33	/kg/d H2	$ 15,333,618.89

Heat Rec/Power Gen			$	27.74	/kg/d Coal	80%	$	27.08	/kg/d Coal	$	140,922,499.49
Balance of Plant			$	13.87	/kg/d Coal	80%	$	13.54	/kg/d Coal	$	70,461,249.75
H2 Cryo Liquefaction	$	700.00			/kg/d H2	75%	$	494.97	/kg/d H2	$	197,989,898.73
Liquid H2 storage	$	5.00			/gal phy vol	70%	$	3.30	/gal phy vol	$	2,462,861.52
Liquid H2 dispenser	$	100,000.00			/dispenser	100%	$	100,000.00	/dispenser	$	500,000.00
									Total Process Units	$	948,821,288.29
					General Facilities & permitting			30%	of process units		$284,646,386.49
					Eng. Startup & contingencies			15%	of process units		$142,323,193.24
					Contingencies			10%	of process units		$94,882,128.83
					Working Capital, Land & Misc			7%	of process units		$66,417,490.18
							Capital Costs		$1,537,090,487.02		per plant

Rate of return:			16%	
Lifetime			30	years
Capital Recover Factor			16.18857%	/yr of capital
Capital Cost			$1,537,090,487	US$
Annualized Recover Cost			$248,832,943.86	US$
Unitized Recovery Cost			$1.89	US$
Unitized Recovery Cost			$3.79	NZ$
Electric Power				
Unitized Electricity Production			24.22	kwh/kg H2
Unitized Electricity Cost @	$	0.08	$1.94	NZ$
Coal				
Energy Conversion			1.054615	GJ/MMBtu
Daily Coal Consumption			140532.06	GJ/d HHV
Unitized Coal Consumption			0.35133015	GJ Coal HHV/kg H2
Unitized Coal Cost @$3.5/GJ			$1.23	NZ$
Operating Costs				
Variable Non-fuel O&M @		1%	$0.23	NZ$
Fixed Operating Cost @		5%	$1.17	NZ$
Total Cost, Non-distributed:			$8.84	NZ$

Transport

450 for south island, 200 for north island

Truck Delivery Distance	450	km
Truck Utilization	80%	

Capital Costs					
Tank & undercarrage		$52,593,750	US$		
Cab		$9,281,250	US$		
Total Capital Costs		$61,875,000	US$		
Annualized Recover Cost @	18%	$11,137,500.00	US$		
Unitized Recover Cost		$0.08499	US$		
Unitized Recover Cost		$0.1700	NZ$		
Variable Operating Cost					
Labor		$14,454,000.00	NZ$		
Fuel		$7,606,828.13	NZ$		
Variable Non-fuel O&M @	1%	$1,237,500.00	NZ$		
Total Variable Operating Costs		$23,298,328.13	NZ$		
Unitized Variable Operating Costs		$0.1778	NZ$		
Fixed Operating Cost @	5%	$6,187,500.00	NZ$		
Unitized Fixed Costs		$0.0472	NZ$		
Total Non-Fuel Costs		$0.2520			
Total Cost, Non-dispensed		$9.24			

Assumptions					
Truck Costs	Tank	$450,000	per tank	US$	
	Undercarraige	$60,000	per trailer	US$	
	Cab	$90,000	per cab	US$	
Truck boil-off rate		0.30%	per day		
Truck capacity		4,000	kg/tank		
Fuel economy		2.53	km/L		6 mpg
Average speed		50	km/h		
Load/unload time		4	hr/trip		
Truck availability		24	hr/day		
Hour/driver		12	hr/driver		
Driver wage & benefits		$20.00	per hr	NZ$	
Fuel price		$0.65	per l diesel	NZ$	
Truck Requirement Calcs					
Trips per year		32,850	trips		90 trips per day

Total Distance	29,565,000	km/yr	
Time for each trip	18.0	hours	
Trip length	22.0	hours, with reloa	Trip Delivered Product
Delivered product	131,038,650	kg/year	3989
Total delivery time	722700	hr/yr	
Total driving time	591300	hr/yr	
Total load/unload time	131400	hr/yr	
Truck availability	7008	hr/yr	
Truck requirement	103	trucks	
Driver time	3120	hr/yr	
Drivers required	232	persons	
Fuel Usage	11,702,812.50	L/yr	
Fuel Usage per kg	0.089308097	L/kg	
FCV			
FCV			
FCV			

Filling Station

Fueling Capacity	2000	kg/d/station	load factor	70%	Vehicles Supported		
Average Consumption	1400	kg/d/station			2,811		
Total Stations	256	stations	17	hour operation			
Tanker every	2.849285714	days					
Liquid H2 storage	14,900	gals (enough to store approx 4,000kg H2)					
Number of Dispensers	6						
Average Dispensing Rate	82.35	kg/hr					
Surge Rate	3	times average					
Surge Rate Per Dispenser	41.18	kg/hr	(Max 48)				
H2 Buffer Storage, enough for	2	hours at surge rate		gal physical vol at 400atm			
H2 Buffer Storage	494.12	kg	3952.941176				
Liquid H2 Pump	0.8	kw/kg/hr					
Electric Power	1120.00	kwh/d					
				Unit cost at			
	Unit cost basis at		*cost/size*	*2000*	*kg/d H2*		
Capital Costs	*1000*	*kg/d H2*	*factors*	$203.06	/kg/d H2	*cost*	
Liquid H2 pump/vaporizer	$250	/kg/d H2	70%	$8.12	/gal phy vol		$406,126.20

Liquid H2 storage	$10	/gal phy vol	70%	$87.06	/gal phy vol	$121,025.61	
H2 buffer storage	$100	/gal phy vol	80%	$15,000.00	/dispenser	$344,123.52	
Liquid H2 dispenser	$15,000	/dispenser	100%	Station Cost		$90,000.00	
				25%	of unit cost	$961,275.32	
	General Facilities & permitting			10%	of unit cost	$240,318.83	
	Eng. Startup & contingencies			10%	of unit cost	$96,127.53	
	Contingencies			7%	of unit cost	$96,127.53	
	Working Capital, Land & Misc				**Capital Costs**	$67,289.27	
						$1,461,138.49	per station (US$)
			Costs (US$)		0.50%		
			Variable Non-fuel O&M @		$ 0.05	$7,305.69	per year
			Electricity @		3%	$20,440.00	per year
			Fixed Operating Cost @		18%	$43,834.15	per year
			Capital Charges @			$263,004.93	per year
			Fueling Station Cost			$334,584.78	per year
			Unitized Fueling Station Cost			$0.65	US$
			Unitized Fueling Station Cost			$1.31	NZ$
			Total Cost			$10.55	NZ$

CARBON

	COAL Carbon	BITUMINOUS		
CO2 Emissions	205.3	lb/MMBTU HHV	2204.62	lbs/tonne
	0.093122624	tonnes/MMBTU		
	0.088300114	tonnes/GJ HHV		
	0.031022492	tonnes/kg H2		
	0.7	t CH4/PJ	GWP	
	1.5	t N2O/PJ	23	t CO2/t Methane
	0.0015511	tonnes CO2 not se	296	t CO2/t N2O
	0.000005656	tonnes CO2 due to CH4		
	0.000155991	tonnes due to N2O		
Total CO2 Equiv.	0.001712772			
Total Carbon Tax	$ 0.043	per kg H2 product @ 25$		

COAL COGEN WITHOUT SEQUESTRATION: 800 tonne plant on the North Island

Central Plant	variables	final costs	totals	guess	Vehicles Supported	1,445,400	
H2 Production		338,696,020.32	SCF/d	0.002362	kg/scf		
H2 Production		800,000	kg H2/d	load factor	90%		
Hourly		33,333	kg/h	coal-HHV efficier	62.41%	HHV	
MJ		4,733,333	MJ H2/h HHV	4733.333333	GJ H2 HHV/h		
Hourly Coal Consumption		13812.50	GJ Coal HHV/h				
Energy Density of Coal		27	MJ HHV/kg				
Daily Coal Consumption		12277778.31	kg/d	907.19	kg/ton	13533.93002	tons per day
Air Separation Unit O2		1.10	metric tons O2/ton dry coal				
ASU O2 Consumption		13505556.14	kg/d O2				
Specific Pre Liquefaction Net Power		1.35	kw/kg/d				
Pre Liquefaction Net Power		1,079,735.64	kw	3887	GJ elec/h		
H2 Liquefaction		11	kwh/kg				
H2 Liquefaction		366,666.67	kw				
Net Power		713,068.97	kw				
CO2 Emissions		36.58936115	kg CO2/kg H2				
CO2 Sequestered @	0%	0	kg/kg H2				
Sequestration Cost		40	$NZ/tonne CO2 Disposed				
Sequestration Cost		$ -	$NZ/kg H2				
CO2 Emitted		0.0365894	tonne CO2/kg H2				
Unitized Carbon Tax @	$ 25.00	$ 0.92	$NZ/kg H2				
Dispenser Statistics		4,000.00	kg/h				
Dispensers Needed		9					
Coal Sulphur Properties		1%	Sulphur				
Liquid Storage		12	hours				
Liquid Storage		400,000	kg liq H2	3.733	gal phy liq H2/kg H2		
Liquid Storage		1,493,200	gal phy liq H2				spare unit
	unit cost basis at			*cost/size*	*unit cost basis at*		20%
Capital Costs	*100,000*	*353,000*	*kg/d H2*	*factors*	*800,000*	*kg/d H2*	*cost for one plant*
Coal handling & prep		$ 4.61	/kg/d Coal	75%	$ 3.76	/kg/d Coal	$ 46,130,896.24
Gasification/Quench/Cln		$ 46.70	/kg/d Coal	85%	$ 41.31	/kg/d Coal	$ 507,153,439.92
Air seperation unit (ASU)		$ 19.29	/kg/d Oxygen	75%	$ 15.72	/kg/d Oxygen	$ 212,332,209.82
Sulfur Polishing		$ 276.88	/kg/d sulfur	80%	$ 235.08	/kg/d sulfur	$ 28,863,142.37
Hydrogen Removal		$ 36.82	/kg/d H2	75%	$ 30.01	/kg/d H2	$ 24,007,390.17
Heat Rec/Power Gen		$ 33.22	/kg/d Coal	80%	$ 28.21	/kg/d Coal	$ 346,303,083.89
Balance of Plant		$ 16.61	/kg/d Coal	80%	$ 14.10	/kg/d Coal	$ 173,151,541.94
H2 Cryo Liquefaction	$ 700.00		/kg/d H2	75%	$ 416.22	/kg/d H2	$ 332,977,992.20

Liquid H2 storage	$	5.00	/gal phy vol	70%	$	2.68	/gal phy vol	$	4,000,930.34
Liquid H2 dispenser	$	100,000.00	/dispenser	100%	$	100,000.00	/dispenser	$	900,000.00
							Total Process Units	$	1,675,820,626.88
			General Facilities & permitting			30%	of process units		$502,746,188.06
			Eng. Startup & contingencies			15%	of process units		$251,373,094.03
			Contingencies			10%	of process units		$167,582,062.69
			Working Capital, Land & Misc			7%	of process units		$117,307,443.88
					Capital Costs		$2,714,829,415.54	per plant	

Rate of return:		16%	
Lifetime		30	years
Capital Recover Factor		15.99623%	/yr of capital
Capital Cost		$2,714,829,416	US$
Annualized Recover Cost		$434,270,300.97	US$
Unitized Recovery Cost		$1.65	US$
Unitized Recovery Cost		$3.30	NZ$
Electric Power			
Unitized Electricity Production		21.39	kwh/kg H2
Unitized Electricity Cost @	$ 0.07	$1.50	NZ$
Coal			
Energy Conversion		1.054615	GJ/MMBtu
Daily Coal Consumption		331500.01	GJ/d HHV
Unitized Coal Consumption		0.414375018	GJ Coal HHV/kg H2
Unitized Coal Cost @$3.5/GJ		$1.45	NZ$
Operating Costs			
Variable Non-fuel O&M @	1%	$0.21	NZ$
Fixed Operating Cost @	5%	$1.03	NZ$
Total Cost, Non-distributed:		$8.41	NZ$

Transport

450 for south island, 200 for north island

Truck Delivery Distance	200	km
Truck Utilization	80%	
Capital Costs		
Tank & undercarrage	$57,375,000	US$
Cab	$10,125,000	US$
Total Capital Costs	$67,500,000	US$

Annualized Recover Cost @	18%	$12,150,000.00	US$		
Unitized Recover Cost		$0.04630	US$		
Unitized Recover Cost		$0.0926	NZ$		
Variable Operating Cost					
Labor		$15,768,000.00	NZ$		
Fuel		$6,761,625.00	NZ$		
Variable Non-fuel O&M @	1%	$1,350,000.00	NZ$		
Total Variable Operating Costs		$23,879,625.00	NZ$		
Unitized Variable Operating Costs		$0.0910	NZ$		
Fixed Operating Cost @	5%	$6,750,000.00	NZ$		
Unitized Fixed Costs		$0.0257	NZ$		
Total Non-Fuel Costs		$0.1373			
Total Cost, Non-dispensed		$8.62			

Assumptions					
Truck Costs	Tank	$450,000	per tank	US$	
	Undercarraige	$60,000	per trailer	US$	
	Cab	$90,000	per cab	US$	
Truck boil-off rate		0.30%	per day		
Truck capacity		4,000	kg/tank		
Fuel economy		2.53	km/L		6 mpg
Average speed		50	km/h		
Load/unload time		4	hr/trip		
Truck availability		24	hr/day		
Hour/driver		12	hr/driver		
Driver wage & benefits		$20.00	per hr	NZ$	
Fuel price		$0.65	per l diesel	NZ$	
Truck Requirement Calcs					
Trips per year		65,700	trips		180 trips per day
Total Distance		26,280,000	km/yr		
Time for each trip		8.0	hours		
Trip length		12.0	hours, with reloading	Trip Delivered Product	
Delivered product		262,405,800	kg/year		3994
Total delivery time		788400	hr/yr		
Total driving time		525600	hr/yr		
Total load/unload time		262800	hr/yr		
Truck availability		7008	hr/yr		

Truck requirement		113	trucks				
Driver time		3120	hr/yr				
Drivers required		253	persons				
Fuel Usage		10,402,500.00	L/yr				
Fuel Usage per kg		0.039642798	L/kg				
FCV							
FCV	55	mpg	88	km per gallon			
FCV	16000	km/year	181.8181818	gallons per year or kg per year per vehicle			

Filling Station

Fueling Capacity	2000	kg/d/station	load factor	70%	Vehicles Supported		
Average Consumption	1400	kg/d/station			2,811		
Total Stations	514	stations	17	hour operation			
Tanker every	2.852857143	days					
Liquid H2 storage	14,900	gals (enough to store approx 4,000kg H2)					
Number of Dispensers	6						
Average Dispensing Rate	82.35	kg/hr					
Surge Rate	3	times average					
Surge Rate Per Dispenser	41.18	kg/hr	(Max 48)				
H2 Buffer Storage, enough f	2	hours at surge rate		gal physical vol at 400atm			
H2 Buffer Storage	494.12	kg	3952.941176				
Liquid H2 Pump	0.8	kw/kg/hr					
Electric Power	1120.00	kwh/d					
				Unit cost at			
	Unit cost basis at		*cost/size*	*2000*	*kg/d H2*		
Capital Costs	*1000*	*kg/d H2*	*factors*	$203.06	/kg/d H2	*cost US$*	
Liquid H2 pump/vaporizer	$250	/kg/d H2	70%	$8.12	/gal phy vol	$406,126.20	
Liquid H2 storage	$10	/gal phy vol	70%	$87.06	/gal phy vol	$121,025.61	
H2 buffer storage	$100	/gal phy vol	80%	$15,000.00	/dispenser	$344,123.52	
Liquid H2 dispenser	$15,000	/dispenser	100%	Station Cost		$90,000.00	
				25%	of unit cost	$961,275.32	
	General Facilities & permitting			10%	of unit cost	$240,318.83	
	Eng. Startup & contingencies			10%	of unit cost	$96,127.53	
	Contingencies			7%	of unit cost	$96,127.53	
	Working Capital, Land & Misc				**Capital Cost**	$67,289.27	
						$1,461,138.49	per station
			Costs (US$)		0.50%		

Variable Non-fuel O&M @	$ 0.05	$7,305.69	per year
Electricity @	3%	$20,440.00	per year
Fixed Operating Cost @	18%	$43,834.15	per year
Capital Charges @		$263,004.93	per year
Fueling Station Cost		$334,584.78	per year
Unitized Fueling Station Cost		$0.65	US$
Unitized Fueling Station Cost		$1.31	NZ$
Total Cost		$9.93	NZ$

CARBON

	COAL Carbon	BITUMINOUS			
CO2 Emissions	205.3	lb/MMBTU HHV		2204.62	lbs/tonne
	0.093122624	tonnes/MMBTU			
	0.088300114	tonnes/GJ HHV			
	0.036589361	tonnes/kg H2			
	0.7	t CH4/PJ	GWP		
	1.5	t N2O/PJ		23	t CO2/t Methane
	0.0365894	tonnes CO2 not sequ		296	t CO2/t N2O
	0.000006671	tonnes CO2 due to CH4			
	0.000183983	tonnes due to N2O			
Total CO2 Equiv.	0.036780015				
Total Carbon Tax	$ 0.920	per kg H2 product @ 25$			

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