Chapter 14

c0075 Kicking the Fossil-Fuel Habit: New Zealand's Ninety Percent Renewable Target for Electricity

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p0095 Abstract

p0100 *The New Zealand Government in 2007 set its sights on 90 percent renewable electricity by 2025, mainly via the expansion of large-scale, centrally dispatched geothermal and wind generation. The country's resource*

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endowments would make this transition feasible at low incremental cost relative to a business-as-usual trajectory, although the foreclosure of small-scale demand-side and distributed generation options by New Zealand's present electricity market design means that the new policy would mainly benefit the large incumbent generators. A renaissance of decentralized and demand-side energy solutions could potentially strand some of the new large-scale renewable projects as well as some legacy thermal capacity. New Zealand's resource endowment is unusually favorable for achieving a return to low-emission electricity generation without resorting to the nuclear option, compared to other countries covered in this book.

s0010 14.1 Background: NZ energy policy and its context

p0105 In October 2007 the New Zealand government declared that 90 percent of the country's electricity should be generated from renewable resources by 2025.[1] The policy measures announced to achieve this goal [32, 38, 39], and passed into law by Parliament in September 2008,[2] were the imposition of a carbon tax[3] on electricity generation provisionally beginning in 2010, and a 10-year restriction on construction of new baseload fossil-fueled electricity generation capacity "except where an exemption is appropriate (for example, to ensure security of supply)."[4] Shortly after passage of the legislation the government fell in the November 2008 general election, and both the Emissions Trading Scheme and the renewables target were put on hold by the incoming National Party administration.

p0110 The regulatory approach set out in the 2008 legislation required any new investment in thermal plant to secure an explicit exemption from the Minister of Energy and to carry the burden of an emissions tax on its operating costs. These measures fell well short of an outright ban, since future ministers would have political discretion at any time to invoke one of the numerous

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[1] New Zealand Energy Strategy to 2050: Powering our future—Towards a sustainable low emissions energy system. Available at: www.med.govt.nz/upload/52164/nzes.pdf, p. 22. October 2007.

[2] Climate Change Response (Emissions Trading) Amendment Act 2008, No. 85; and Electricity (Renewable Preference) Amendment Act 2008, No. 86.

[3] Although described as an "emissions trading scheme," the New Zealand scheme is in fact a tax, with the tax rate determined by arbitrage with the world carbon market. See Bertram and Terry (2008), Chapter 4.

[4] Electricity (Renewable Preference) Amendment Act 2008, section 4, new s.62A of the Electricity Act 1992. The bill passed into law in September 2008.

loopholes built into the legislation[5] and allow a raft of new nonrenewable generation to be built, and the legislation itself could be repealed. Neither the emissions tax nor the requirement for new thermal plant to gain "exemption" have enjoyed bipartisan political support, which means that neither was entrenched.

p0115 New Zealand is nevertheless well endowed with resources to sustain increased renewables-based generation [44]. Over the next three decades New Zealand is likely to require 8000 MW of additional generation capacity (roughly a doubling of the existing total); against this, around 6500 MW of feasible large-scale (over 10 MW) renewables-based options have been identified with long-run marginal cost below NZ$130/MWh (13 cents/kWh). Five thousand MW of this has cost below $100/MWh. Building this 6500 MW of renewables as part of the 8000 MW expansion would raise the renewable share of capacity from its present 69 percent up to 75 percent. Achieving the 90 percent target would then require a further 15 percent shift in the makeup of the country's generation portfolio, with fossil-fired generation displaced by some combination of greater renewables penetration and changes in electricity demand.

p0120 The prospects of success seem good. On the supply side, technological progress is cutting the costs of wind, wave, and solar technologies, whereas fossil-fuel prices for electricity generators in New Zealand have been rising after four decades of access to cheap natural gas. The country's potential large-scale wind resource, including feasible projects costed at over $130/MWh, is assessed at over 16,000 MW.[6]

p0125 On the demand side, including distributed small-scale generation, progress has been held back more by institutional barriers than by lack of options. The oligopolistic structure of the electricity market has effectively foreclosed entry by independent brokers and small generators; pro-competitive regulatory measures such as feed-in tariffs and net metering are yet to be introduced, two decades after market restructuring began. Over time these obstacles to technological progress and competitive entry are unlikely to be sustainable.

p0130 With relative prices and technological progress swinging the market balance in favor of renewables over the past 5 years, the dominant New Zealand generators have been racing to secure strategic footholds on key renewable

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[5] The Electricity (Renewable Preference) Amendment Act 2008 s.4 automatically exempts all existing generation plants and allows new plants to be exempted by regulatory declaration. The new Electricity Act Section 62G allows exemptions to be granted for baseload plants that mitigate emergencies, provide reserve energy, supply isolated communities, function as cogeneration facilities, use a mix of renewable and fossil fuels or waste and fossil fuels, or replace existing plant with a more emission-efficient process.

[6] See Table 14.4.

resources by constructing large wind farms and geothermal plants.[7] As the next section describes, this move represents the reversal of a half-century-old trend away from renewables.

p0135 The chapter explores the feasibility of the renewables target and the 2008 policy framework. Section 14.2 sets out the record of New Zealand's 1970–2000 shift away from its historically high renewables share; Section 14.3 reviews some common issues with integrating renewables into an electricity system. Section 14.4 reflects on the achievement of 100 percent renewable electricity supply in Iceland and compares it with New Zealand, and Section 14.5 reviews the New Zealand government's modeling work on the future evolution of the generation portfolio in New Zealand and considers some implications of the supply-side bias built into New Zealand's electricity market design. Section 14.6 pulls together the main conclusions.

s0015 14.2 Historical development of the New Zealand system

s0020 14.2.1 THE RISE AND (RELATIVE) FALL OF HYDRO

p0140 Electricity reached New Zealand in the 1880s, when the country was still in its pioneering phase [31]. By the time of the First World War the country had a patchwork of local standalone supply systems and associated distribution networks, each with its own voltage and frequency standards. Starting in the 1920s an integrated supply network was established in each of the two main islands under government auspices, including the construction of large state-owned hydroelectric stations, which dominated supply by the mid-1960s.

p0145 Because of its mountainous topography, New Zealand was well endowed with opportunities to construct large-scale hydro. By the 1940s the share of fossil fuels in total capacity had fallen below 10 percent (Figure 14.2), with small oil-fired plants providing local peaking capacity and about 50 MW of coal-fired plants in Auckland and Wellington providing backup supply. Through the 1950s demand grew ahead of the pace of hydro construction and the gap was filled by investment in coal and geothermal plants (Figure 14.1). New hydro construction accelerated in the 1960s as a cable connecting the North and South Islands made possible the development of large hydro resources in the far south, to supply the northern market [43].

p0150 As Table 14.1 and Figure 14.1 show, the pace of hydro and geothermal construction slowed in the 1970s while that of fossil-fired thermal generation

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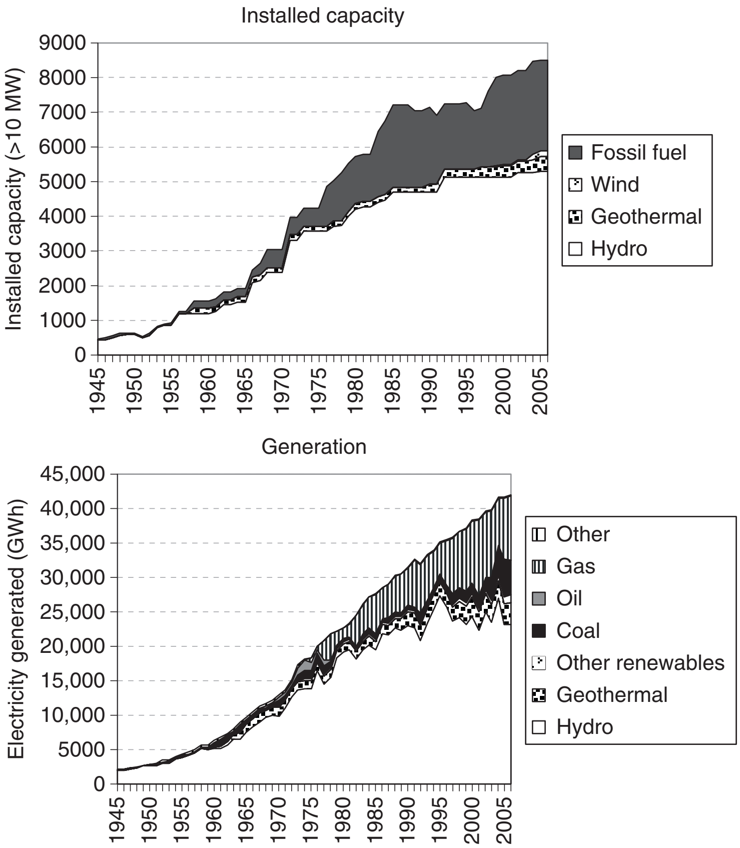
[7] One would-be new entrant/entrepreneur is experimenting with very large-scale, subsea tidal generation: Neptune Power Ltd., "Response to the MED request for submissions to the Draft New Zealand Energy Strategy," March 2007, www.med.govt.nz/upload/47260/205.pdf; "Trial Approved for Strait Tidal Power," *Dominion Post* 2 May 2008, www.stuff.co.nz/4505727a11.html.



f0010 **Figure 14.1** New Zealand electricity installed capacity and generation by fuel type, 1945–2006.
Source: 1945–1956 calculated from *Annual Reports* of the New Zealand Electricity Department, 1945–1956; 1956–1973 Ministry of Economic Development unpublished data; 1974–2006 from Energy Data File, June 2008, p. 100.

increased sharply. Over the two decades from 1965 to 1985 the fossil-fuel share of capacity rose from 11% to 33%. In 2004 it was still 32%.[8]

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[8] As Bertram (2007), pp. 224–225, notes, the introduction of "commercial" incentives and behavior under the reforms of 1987–1992 led quickly to the decommissioning of reserve thermal capacity, which was costly to maintain but held prices down during the dry winter of 1992, thereby reducing generation profits. The demolition of this 620 MW of privately unprofitable plant temporarily cut the fossil-fuel share of capacity to 25 percent in the mid-1990s while sharply reducing the system's security margin and increasing the economy's exposure to blackouts in dry years.

t0010 **Table 14.1** Fuel shares of NZ electricity generated for the grid, 1945–2007 (5-year averages, GWh per year)

	Geothermal	Hydro	Wind	Biomass	Coal and Oil	Gas	Cogen	Other	Total	Renewables (%)
1945–1949	0	2322	0	0	111	0	0	39	2472	94
1950–1954	0	3204	0	0	171	0	0	241	3616	89
1955–1959	27	4720	0	0	319	0	0	297	5363	89
1960–1964	716	6136	0	0	825	0	0	319	7995	86
1965–1969	1204	9240	0	0	770	0	0	346	11,561	90
1970–1974	1215	13,027	0	63	1986	42	0	299	16,632	86
1975–1979	1243	16,035	0	357	1498	2303	0	0	21,436	82
1980–1984	1194	19,300	0	403	613	3276	0	0	24,787	84
1985–1989	1314	21,633	0	442	697	5123	0	0	29,209	80
1990–1994	2176	23,067	1	488	758	6177	0	0	32,667	79
1995–1999	2244	24,791	17	494	1318	7227	0	0	36,089	76
2000–2004	2669	24,427	182	513	2598	9132	63	0	39,585	70
2005–2007	1896	13,901	431	415	2690	5849	26	0	25,208	66

Source: NZED, annual statistics in relation to electric power development and operation; Ministry of Economic Development Energy Data File, June 2008.

s0025 14.2.2 CHEAP GAS, RELATIVE COSTS, AND THE RISE OF NONRENEWABLES

p0155 New Zealand's transition from 90 percent renewable electricity in the early 1970s to 65 percent in 2006 (in terms of generation output) was a direct result of relative-cost trends. The availability of cheap natural gas from the giant offshore Maui field[9] and the rising cost of large hydro construction, as development of the most accessible and suitable river systems was completed and diminishing returns to hydro set in, produced a relative-price swing directly contrary to the international effect of the first two oil shocks.

p0160 New Zealand's Maui gasfield was developed under a long-term take-or-pay contract signed in 1973 with the government as buyer, at a delivered-gas price that was only incompletely inflation indexed. As a result, the real fuel cost of state-owned thermal generation fell steadily through the 1970s and 1980s (Figure 14.2). A fully indexed purchase-and-sale agreement between the Crown and ECNZ[10] was negotiated in 1989, but the fuel cost per kWh of generation continued to fall during the 1990s due to the rising efficiency of baseload thermal capacity and the scrapping of reserve thermal plant.

p0165 The oil shocks of 1973 and 1980 would probably have forced a reorientation back to renewables (especially geothermal) but for the fortuitous coincidence of major natural gas discoveries with no means of exporting the gas. The result was to delink thermal generation costs from world oil prices.

p0170 Figure 14.2 shows a sharp increase in fuel cost in the two years after the first oil shock in 1973, when existing thermal capacity was coal or oil fired, but over the following decade natural gas completely displaced oil and largely displaced coal, so that the second world oil price shock of 1979–1980 had no effect on the downward-trending fuel cost of generation. A large oil-fired plant at Marsden Point, which had accounted for over 6 percent of total supply in 1974, was downgraded to dry-year reserve status by 1980.[11]

p0175 Figure 14.3 shows the rapid post-1973 elimination of oil (and to a considerable extent, coal) from thermal electricity generation, a trend eventually reversed by a revival of coal use only from 2003 on as Maui output fell and the gas price rose.[12]

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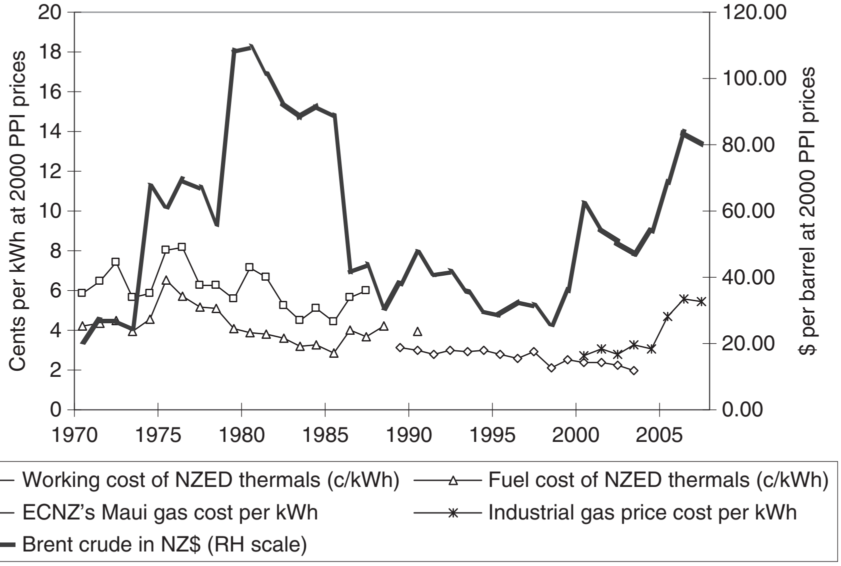
[9] Discovered 1969, onstream in 1979, peaked in 2001, now in decline.

[10] Electricity Corporation of New Zealand, the corporatized successor to NZED.

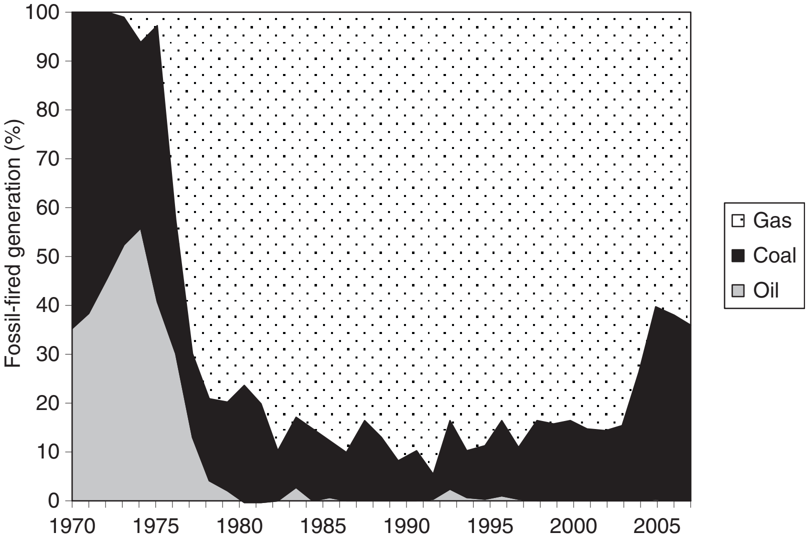
[11] The second major oil-fired plant at Marsden was completed in 1978 but never commissioned.

[12] New Zealand's coal reserves are large, and the lifetime cost of electricity from coal plants remains competitive in the absence of a carbon tax. However, the combination of the planned emissions trading scheme and 10-year moratorium on new baseload thermal plants will keep coal at the margin of the future electricity generation portfolio.



f0015 **Figure 14.2** Real fuel cost of fossil-fired generation in New Zealand compared with world oil price trends, 1970–2005.

Source: Brent crude price from IMF, *International Financial Statistics*, converted to New Zealand dollars at current exchange rates and deflated by the New Zealand Producer Price Index (Inputs). NZED per-kWh fuel cost and thermal operating cost 1970–1991, calculated from NZED, *Annual Statistics in Relation to Electric Power Development and Operation*. ECNZ's fuel cost per kWh using Maui gas is the 1989 contract price of $2.225/GJ escalated to 2000 dollars using the PPI (Inputs), combined with thermal generation data from *Energy Data File,* June 2008, www.med.govt.nz/upload/59482/00_EDF-June2008.pdf, Table G2, p. 100, and gas used in generation from Ministry for the Environment, *Revised New Zealand Energy Greenhouse Gas Emissions 1990–2005*, December 2006, www.med.govt.nz/upload/38637/GHG%20report.pdf, Table 2.2.1, p. 33. Fuel cost per kWh 2000–2007 at the industry gas price: calculated using industry gas price from *Energy Data File,* June 2008, www.med.govt.nz/upload/59482/00_EDF-June2008.pdf, Table J4, p. 136; thermal generation data from *ibid.*, Table G2, p. 100; and gas used in generation from Ministry for the Environment, *Revised New Zealand Energy Greenhouse Gas Emissions 1990–2005,* Table 2.2.1, p. 33. PPI deflator from *Statistics New Zealand Long-Term Data Series,* www.stats.govt.nz/tables/ltds/ltds-prices.htm, Tables G3.1 and G3.2, updated 2004–2007 using the *INFOS* database.



f0020 **Figure 14.3** New Zealand's switch to gas in thermal generation, 1970–2005. Source: NZED, annual statistics in relation to electric power development and operation; Ministry of Economic Development Energy Data File, June 2008.

p0180 The switch to cheap gas and consequent rising reliance on fossil fuel, seen in Figures 14.1–14.3, cannot be repeated today in the face of the rising world oil price since 2003, because no new gasfield on the scale of Maui has been found and because the emergence of a global LNG market means that the domestic price of gas has become linked once again to the oil price.[13] In the coming two decades, the cost of gas for New Zealand generators will move with (and to) the world oil price, placing a squeeze on the profitability of thermal generation relative to renewables. This squeeze will be exacerbated to the extent that a carbon tax is actually imposed on thermal generation.

p0185 The change in the profitability of renewables relative to nonrenewables since 2000 has been rapidly reflected in a surge of new investment in wind and geothermal capacity. By October 2007, when the Labour government announced its new strategy of aiming for 90 percent renewables and restraining construction of new thermal plants, market forces were already moving strongly in that direction. Electricity sector modelers in the New Zealand

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[13] New Zealand does not yet have any LNG terminal, but the world LNG price is already used by the industry and the government as a pricing benchmark.

Electricity Commission and the Ministry of Economic Development estimated in late 2007 that a carbon tax of NZ\$50/tonne[14] CO_2-equivalent would by itself make a 90 percent renewables share fully economic by 2030.[15]

s0030

14.3 Integrating renewables

p0190 With oil and gas prices trending upward and carbon taxes in prospect, fossil fuels will increasingly be confined to specialized roles in electricity generation. The two main ones in New Zealand are cogeneration (where electricity is a joint product from the burning of fuel for industrial process heat) and reliability support for the system: dry-year backup for hydro and reliable peaking capability to offset the intermittency of some renewable generation technologies. This section reviews the intermittency problem and some other issues with the displacement of fossil fuels by renewables.

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14.3.1 INTERMITTENT RENEWABLES AND RELIABLE NONRENEWABLES

p0195 Primary energy sources are generally classified as renewable or nonrenewable on the basis of whether they draw on a depleting energy resource. Fossil fuel is nonrenewable, whereas hydro, wind, solar, and wave power are generally treated as renewable. On the borderline are nuclear,[16] which depletes its fuel stock but at a relatively slow rate, and geothermal energy (Williamson, Chapter 11 of this volume), which in most cases draws on an underground reservoir of heat sufficiently large to enable depletion to be ignored within the usual planning horizons for energy supply.[17] Here geothermal is treated as renewable. It is also a technology that is relatively benign in terms of carbon emissions—emissions are low, though not zero.

p0200 An important difference between renewables and nonrenewables is the degree of flexibility and controllability in the rate and timing of generation. A well-designed portfolio of fossil-fuel generating plants can be operated to

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[14] Roughly US\$30.

[15] Samuelson R, et al. Supplementary Data Files, "Emission Pricing on all Sectors," Figure 6b; 2007.

[16] Nuclear power is ruled out for New Zealand by a long-standing bipartisan political consensus.

[17] Note, however, the case of the geothermal project developed in New Zealand at Ohaaki, where a 104 MW plant was commissioned in 1989 but had been derated to 40 MW by 2005 due to unexpected depletion of the resource, accelerated by the cooling effect from reinjection of cooled fluids directly into the reservoir. See www.nzgeothermal.org.nz/geothermal_energy/electricity_generation.asp.

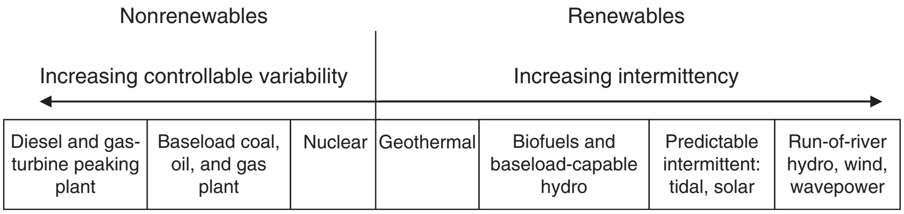
follow load with few constraints. Renewables-based generation, in contrast, is dependent on natural processes to supply the primary energy, which means that electricity systems with very high percentages of renewable generation must be designed with an eye to constraints that are outside the control of the system operator: wind and wave fluctuations, rainfall, the daily cycle of solar radiation, the regular but time-varying movement of tides. This intermittency must be offset in some way—by storage technologies that enable generation and consumption of electricity to be separated in real time, or by reliance on nonrenewable generators able to ramp up and down to fill gaps in renewable supply, or by a demand side that is able to respond in real time to price signals reflecting fluctuations in supply.

p0205 The operational difference between a fully renewable system and a fully nonrenewable one lies not in the baseload part of the spectrum but in the nature and extent of output variations in nonbaseload plants (Figure 14.4).

p0210 In a nonrenewables generation portfolio, the system operator is able to use peaking plant to follow load fluctuations, which means that the adequacy and reliability of supply are straightforwardly determined by human decisions on construction, maintenance, fuel procurement, and system dispatch. The “increasing variability” on the left side of Figure 14.4 is therefore a positive feature of the generation portfolio.

p0215 In a renewables portfolio, “increasing intermittency,” on the right side of Figure 14.4, reflects output variations that are driven not by load following but by natural processes that are largely uncorrelated with demand peaks. The system operator therefore needs to have some controllable component of the overall system that can be called on to keep supply and demand continuously in balance. These issues are discussed in relation to wind power by Wiser and Hand (Chapter 9 in this volume).

p0220 Research by the New Zealand Electricity Commission [13, 14, 15, 16] suggests that there is no physical feasibility limit to integrating wind into the New Zealand system up to around 50 percent of total generation, but there are likely to be



f0025 **Figure 14.4** Schematic comparison of renewable and nonrenewable technologies.

rising costs of ancillary services to maintain reliability of supply, and these costs would be reflected in wholesale prices ([1], Section 7).

p0225 In most electricity systems, wind generation is treated as a nondispatchable source of variation in the residual demand faced by central generators [18, 19]. In contrast, New Zealand's large new wind farms are included in the system operator's central dispatch schedule on the basis of a 2-hour-ahead "persistence forecast" of their output and at a constrained must-run offer price of zero or NZ$0.01/MWh ([1]; Electricity Governance Rule 3.6.33[18]). Dispatch is possible because virtually all the wind farms are owned by large generator-retailers with sufficiently diversified generation portfolios to allow intrafirm backup, usually from hydro, and because of the relatively high load factor of wind in New Zealand, generally 30–45 percent. The virtual absence of distributed wind generation, injecting power downstream of exit points from the grid, means that variability of residual load on the grid due to distributed wind has not yet been an issue in New Zealand.

p0230 In New Zealand, hydro generation has historically provided controllable variability. Hydro is a high-quality renewable, combining baseload and peaking capability, although it faces limitations imposed by New Zealand's rivers, which allow only limited storage and which are subject to minimum and maximum flow restrictions for environmental reasons. Development of hydro resources in New Zealand has, however, reached a mature stage, with few major rivers remaining undammed and rising costs of developing them for electricity—not only construction costs but also the rising opportunity value of wild and scenic rivers to the country's tourism industry, which is now the leading earner of foreign exchange.

p0235 The planned return to 90 percent renewables would therefore have to rely mainly on geothermal development combined with wind, wave, and tidal generation. To offset the intermittency of these last three technologies, a traditional solution would be to construct gas-fired or oil-fired peaking plant to cover for periods when demand is high and wind and wave are offline. However, if such new fossil-fired capacity is built and allowed to bid for dispatch, the market will be apt to "choose" a significant amount of electricity supply from these fossil-fired stations, which would rule out a 100 percent renewables system and could make even 90 percent problematic.

p0240 The combination of a commercially driven wholesale market for generation and a rising systemic requirement for backstop capacity that would operate for only part of the time raises issues of contract design and regulation that have not been resolved. In recent times a perceived shortfall of backstop capacity to

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[18] The full set of Electricity Governance Rules is posted on the Web at www.electricitycommission.govt.nz/pdfs/rulesandregs/rules/rulespdf/complete-rules-5Jun08.pdf.

cover for dry years (when hydro generation is low) led to the government constructing a peaking station that is blocked by regulation from bidding into the market except at times of penal wholesale prices (over $200/MWh). If a rising renewables share is accompanied by increasing need for backstop reserve capacity, and if the backstop technology is fossil-fueled supply, restraining thermal generation below 10 percent of total generation is likely to require either a very high carbon tax or regulatory limits on the dispatch of thermal capacity once its construction cost has been sunk, or both. At this stage such policy issues have not been addressed, at least not publicly.

p0245 The problem of intermittency is obviously far less in an electricity system that is interconnected with other countries, as are the United Kingdom (with backup from the EU) and most states of the United States apart from Hawaii. In such cases, a target for the proportion of renewables in domestic generation may be met even when a substantial proportion of demand is served from externally located nonrenewables.

p0250 New Zealand, like Hawaii and Iceland, is an island system without interconnection to any other country, although the country's two main islands are interconnected and provide mutual support. Integrating intermittent renewables is in principle more challenging for island systems than for continental ones because of the lack of external backup. When the island market is small, it also suffers from inability to reap economies of scope and scale in maintaining reliability standards.

p0255 Much depends, of course, on precisely which mix of renewables is actually installed [23]. Diversification helps: a range of technologies spread over a range of locations can smooth out the consequences of intermittency at the level of the single generating unit [42]. Having wind farms dispersed across a wide geographical area should result in a more reliable flow of generation because wind speeds vary from place to place and fluctuations in wind speed are less likely to be correlated across widely dispersed sites. Intermittency patterns of wind, waves, tides, and rainfall can offset one another so that the probability of securing a reliable, hence easily dispatchable, flow of electricity rises as the number of interlinked technologies increases [22].

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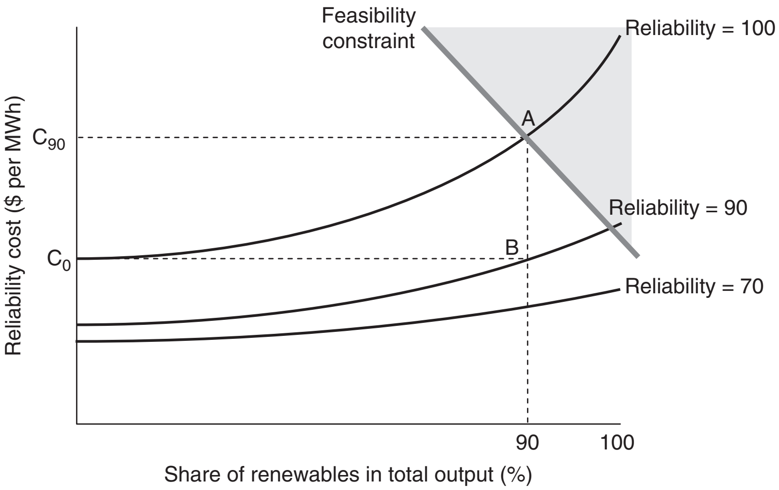
14.3.2 A MODEL OF THE TRADE-OFF

p0260 Conceptually, the intermittency problem can be captured by a diagram such as Figure 14.5. Here iso-reliability contours (indexed with 100 percent reliability as the initial target) are drawn sloping up on the assumption that as the share of renewables in the generation portfolio rises (horizontal axis), the cost of procuring the necessary capacity reserves to maintain any target level of reliability (vertical axis) rises at the margin (as is the case for, e.g., wind



f0030 **Figure 14.5** Framework for the integration of renewables into a hypothetical electricity system.
Source: Marconnet (2007), p. 78a [30].

penetration in the EU ([2], pp. 6–7). At Point A, to meet a 90 percent renewables target with 100 percent of target reliability, the cost C_{90} must be incurred, whereas the system with zero renewables is shown as having a full-reliability cost of C_0. The difference between these two represents the cost of moving toward more renewables without sacrificing quality of supply. Holding the electricity price at C_0 while pushing the renewables share up to 90 percent in this case would reduce reliability to $R = 90$ (Point B).

p0265 A hypothetical feasibility constraint is included in Figure 14.5 to take account of the possibility that, for a particular country, its resource endowment or particular characteristics of its electricity load may place some ceiling on the ability of the system to "buy" reliability as renewables increase their share. The position and slope of the constraint would be determined by both resource endowments and the state of technology. If it exists, the menu faced by policymakers seeking to maximize renewables subject to cost and feasibility constraints would be the set of corner solutions between the reliability contours and the feasibility constraint, including in this case Point A.

p0270 The position and slope of the contours in Figure 14.5 depend on the nature, diversity, and geographical dispersion of a country's renewable resources. An important modeling issue in the New Zealand case is the slope of these contours, which will dictate the long-run costs of moving to a high-renewables system relative to a status quo one.

p0275 The intermittency problem can be addressed on both demand and supply sides of the market. On the supply side, intermittency can be reduced greatly by technological progress in the design of wind and wave farms to render them more controllable and able to contribute directly to maintenance of frequency and voltage on the overall grid, and by installing substantial excess renewables capacity in diversified locations [24]. On the demand side, real-time pricing to final consumers and implementation of a range of energy-efficiency innovations can increase the flexibility of demand response to variable supply.

p0280 Two of the renewable supply technologies are not subject to intermittency: geothermal (Williamson, Chapter 11 in this volume) and hydro with storage. These are the key to the ability of Norway and Iceland to operate fully renewables-based generation portfolios, discussed in the next section.

s0045 14.4 Norway and Iceland as models

p0285 Within the OECD there are two very high-renewable electricity systems: Norway (99 percent renewables) and Iceland (100 percent). New Zealand ranks third behind these so long as nuclear is classified as nonrenewable (Figure 14.6).

p0290 Norway is not comparable with New Zealand since its hydro has massive storage capacity and is backed up by neighboring Sweden's large nuclear capacity, which gives Norway almost complete security of supply.

p0295 Iceland, however—an island system like New Zealand—is 100 percent renewable in terms of generation on the main island.[19] Iceland confronts no operational problems with integration of renewables, because its portfolio is dominated by two perfectly matched renewable technologies: hydro and geothermal. Geothermal provides reliable baseload and is fully dispatchable; hydro provides peaking capacity and is also dispatchable. In 2006 Iceland had five major geothermal plants producing 26 percent of total electricity consumption, while 0.1 percent came from fossil fuels and the remaining 73.4 percent was from hydro.[20]

p0300 Like New Zealand, Iceland embarked on large hydro construction in the 1920s and has ever since had a system based primarily on hydro. In the 1960s and 1970s, roughly 100 MW of oil-fired plant was built, bringing the total thermal capacity up to 125 MW, but following the oil shocks of the 1970s this capacity was stranded by a dramatic expansion of renewable capacity as part

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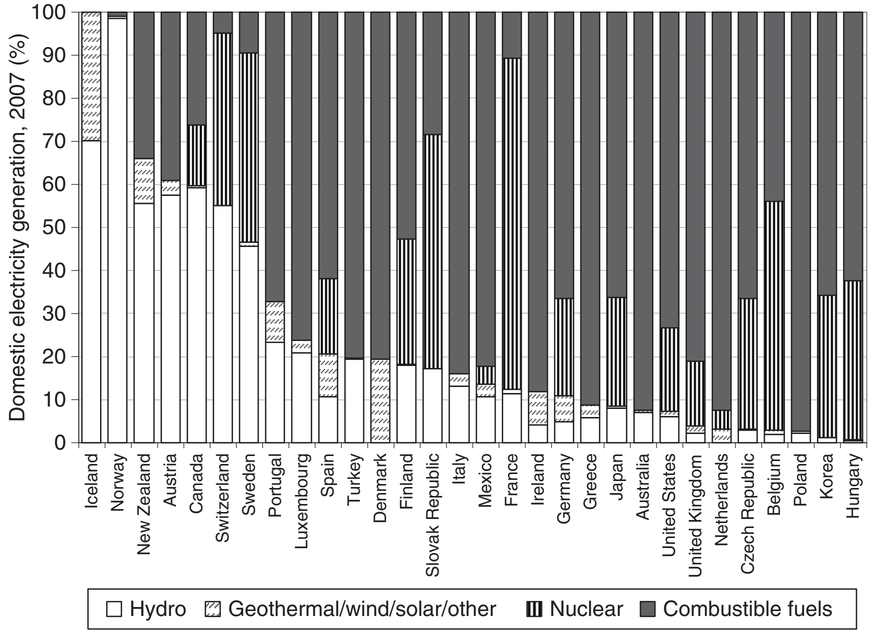
[19] The offshore island of Grimsey has a diesel-powered generator.

[20] Geothermal Power in Iceland. Available at: http://en.wikipedia.org/wiki/Geothermal_power_in_Iceland, downloaded April 2008.



f0035 **Figure 14.6** Electricity generation by primary energy source, OECD countries. Source: IEA, *Electricity Statistics,* www.iea.org/Textbase/stats/surveys/MES.XLS

of a policy of reducing dependence on oil and coal [21]. Between 1975 and 1985 installed hydro capacity doubled from 389 MW to 752 MW while geothermal capacity increased fifteen-fold, from 2.1 MW to 41.2 MW. After 1981 Iceland's fossil-fuel plants never supplied more than 9 GWh per year (around 0.1 percent of total supply), mainly to areas not connected to the grid. Geothermal now accounts for 25 percent of total installed capacity of 1698 MW, and hydro another 68 percent. The remaining 7 percent appears to be mainly residual thermal capacity, which provides a backstop for the system's reliability of supply and peaking ability but is hardly ever required.[21]

p0305 Table 14.2 gives comparative data for Iceland and New Zealand. Although with a population less than one tenth that of New Zealand, Iceland has per capita electricity generation more than three times as great. Both nations have over 60 percent of capacity accounted for by hydro, but Iceland's greater storage enables it to convert this to 73 percent of total supply, whereas New Zealand's hydro accounts for only 55 percent of supply.

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[21] "Energy Statistics in Iceland," Orkustofnun (Iceland Energy Authority), www.statice.is/Statistics/Manufacturing-and-energy/Energy

t0015 **Table 14.2** New Zealand and Iceland compared, 1970 and 2006

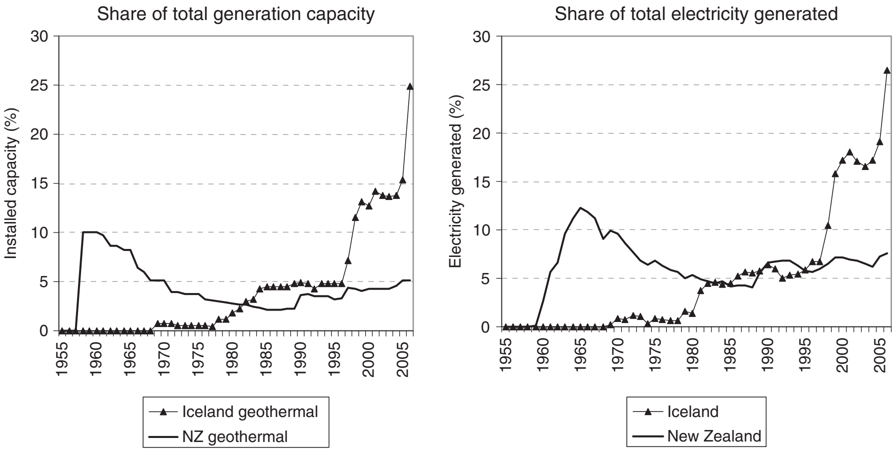
	Iceland				New Zealand			
	1970		2006		1970		2006	
		Share (%)		Share (%)		Share (%)		Share (%)
Population (000)	204	—	304	—	2852	—	4173	—
Generation per capita, MWh	7.2	—	33	—	4.5	—	10	—
Electricity generated (GWh)	**1460**	—	**9925**	—	**12,926**	—	**42,056**	—
Hydro	1413	97	7289	73.4	9889	76.5	23,220	55
Geothermal	12	1	2631	26.5	1243	9.6	3210	8
Wind	0	0	0	0.0	0	0.0	617	2
Fossil fired	35	2	5	0.0	1471	11.4	14,322	34
Generation capacity, 2006 (MW)	**334**	—	**1698**	—	**3040**	—	**8517**	—
Hydro	244	17	1163	12	2373	18.4	5283	13
Geothermal	2.6	0.2	422	4	157	1.2	435	1
Wind	0	0	0	0	0	0	171	0.4
Fossil fired	88	6	113	1	510	3.9	2628	6

Source: Iceland data from Statistics Iceland Webpage, www.statice.is. New Zealand from Ministry of Economics Development, Energy Data File, www.med.govt.nz/templates/StandardSummary____15169.aspx, and population from Statistics New Zealand, www.stats.govt.nz/tables/ltds/default.htm.

p0310 The two obvious contrasts between the two countries are their different reactions to the 1970s oil shocks and the extent to which they have developed their geothermal resources. Looking at the historical evolution of the New Zealand generation portfolio (Figure 14.1), geothermal development stalled after the 1950s, despite the existence of a large-scale resource, and its share of total supply fell from around 12 percent in the mid-1960s to only 4 percent by 1990 (see Figure 14.7). Although New Zealand pioneered geothermal generation in the 1950s, the technology fell back to below 5 percent of capacity after 1970, whereas in Iceland, where the first geothermal plant appeared only in the 1970s, geothermal rose rapidly to a quarter of total generation capacity by 2006.

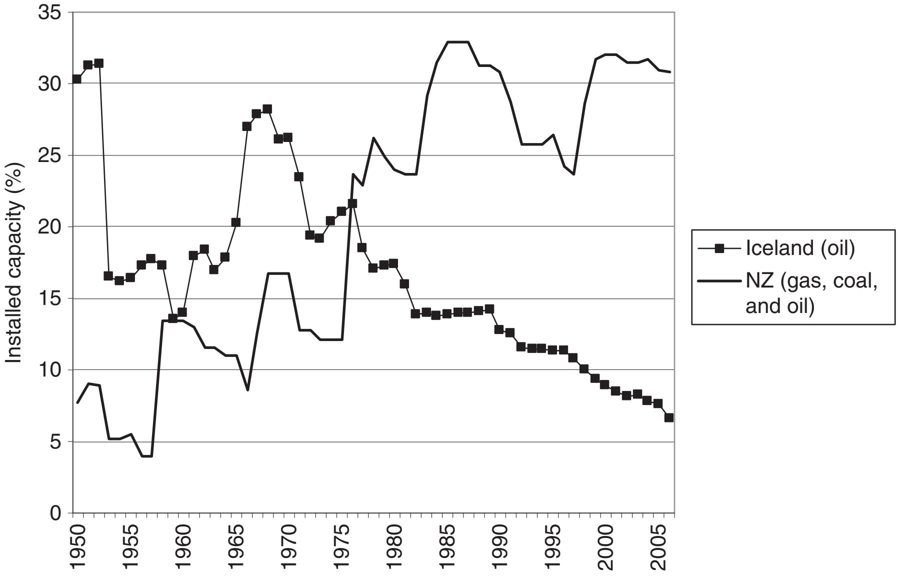
p0315 Confronted with the oil shocks of the 1970s, both countries delinked their electricity supply systems from world oil prices, but they did so by very different means. Iceland, whose thermal generation relied entirely on imported oil, delinked by building enough new hydro and geothermal capacity to effectively eliminate fossil fuels from its generation mix by 1983. New Zealand, as outlined earlier, delinked by switching to locally produced natural gas via a large-scale thermal generation construction program that raised the nonrenewables share of capacity to about one third by 2006 (Figure 14.8).

p0320 Iceland's strategy of delinking from oil prices by eliminating fossil fuels from its electricity sector means it now has a permanent buffer against volatile oil



f0040 **Figure 14.7** Geothermal shares of capacity and generation, New Zealand and Iceland, 1955–2005.

Source: Iceland, from Statistics Iceland website, www.statice.is/Statistics/Manufacturing-and-energy/Energy; New Zealand, from Ministry of Economic Development *Energy Data File*.



f0045 **Figure 14.8** Nonrenewables share of installed capacity, 1950–2005. Source: Iceland, from Statistics Iceland website, www.statice.is/Statistics/Manufacturing-and-energy/Energy; New Zealand, from Ministry of Economic Development Energy Data File.

markets, whereas New Zealand's strategy of a switch to cheap gas was effective only so long as the Maui Contract dictated the local gas price. New Zealand is now in the process of embarking on the Icelandic path, 40 years later.

s0050 14.5 Modeling the future NZ portfolio

p0325 Whether moving to 90 percent renewables is feasible for New Zealand at acceptable cost is an issue best addressed by systematic modeling. This section reviews recent work on the future evolution of electricity generation in New Zealand under a variety of assumptions about policies and prices.

p0330 Since 2000 the New Zealand Ministry of Economic Development has conducted several rounds of scenario work using its SADEM model [33, 34, 35]. In addition, the Parliamentary Commissioner for the Environment has produced a scenario study focusing on renewables, distributed generation, and demand-side response [41, 45], and Greenpeace has carried out a less formal study [20] as part of a worldwide modeling exercise [5]. The leader in the field at present is the Electricity Commission, the new sector regulator set up in 2003 (for background, see [6], p. 232).

s0055 14.5.1 THE ELECTRICITY COMMISSION'S GEM MODEL

p0335 The Electricity Commission has developed a Generation Expansion Model (GEM) to simulate alternative scenarios for the generation portfolio and select the most cost-effective one [8, 9]. The GEM determines the optimal commissioning dates of new generation plants and transmission equipment in response to an exogenously imposed forecast of demand for electricity. The GEM also simulates the optimal dispatch of both existing and new plants.

p0340 The model's objective function is to build and/or dispatch plants in a manner that minimizes total system costs while satisfying a number of constraints. The main constraints are to:[22]

- u0090 Satisfy a fixed load in each load block of each time period within each year
- u0095 Satisfy peak-load security constraints
- u0100 Provide the specified reserves cover
- u0105 Account for both capital costs incurred when building new plants and fixed and variable operating costs of built plants, including any specified carbon charge on the use of CO_2-emitting fuels
- u0110 Satisfy energy constraints arising from the limited availability of hydro inflows
- u0115 Satisfy HVDC constraints[23]

p0375 Underlying the "generation scenarios" part of the model [10, 11] is a database of possible new generation options, their associated capital and fuel costs, plant performance, depreciation, and load factors, based on Parsons Brinckerhoff Associates findings [40] and subsequent updates. The model also requires estimates of future hydro flows, the cost of carbon, and forecast loads during the various load blocks.[24] These technical supply-side data appear in

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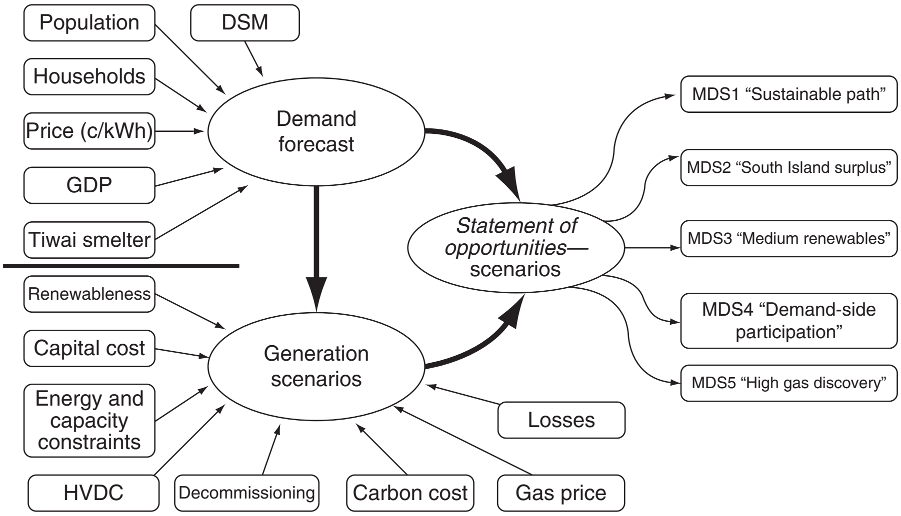
[22] This list is from the Electricity Commission's programmers' notes within the main GAMs batch file.

[23] *HVDC* refers to the high-voltage direct current link between the two main islands of New Zealand.

[24] The load blocks used by the commission are:

b0n	A no-wind peak spike
b0w	A windy peak spike
b1n	A peaky no-wind block
b1w	A peaky windy block
b2n	A shoulder no-wind block
b2w	A shoulder windy block
b3	A mid-order block
b4	An off-peak shoulder block
b5	An off-peak block



f0050 **Figure 14.9** Schematic representation of the Electricity Commission's modeling. Source: Adapted from Hume and Archer, Figure 14.2, p. 2 [26].

the lower-left part of Figure 14.9 as inputs to the least-cost generation scenarios.

p0380 The other key input, also shown in Figure 14.9, is the demand forecast, which is based on modeling of three sectors—residential, commercial, and industrial—and "heavy industry" (the Tiwai Point aluminium smelter, which accounts for 17 percent of national load). Forecasts are done at both national and regional levels [27].

p0385 The national-level modeling of residential and commercial/industrial demand uses regression analysis, with GDP/capita, number of households, and electricity price as the explanatory variables. The commercial and industrial model has only two variables: GDP and "shortage."[25] Demand from heavy industry is assumed to be constant, unless the GEM scenario involves closure of the aluminum smelter. The forecasts currently assume that future rates of improvement in energy efficiency are the same as historical rates, with no feedback to the "DSM" input box in Figure 14.9.

p0390 Regional-level load forecasts cannot be undertaken with econometric methods due to lack of historical data. Therefore, the model's regional forecasts are based

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[25] The shortage variable is a dummy that removes from the regression results years in which "shortages" have occurred. This is done to ensure that demand is not biased downward due to extraordinary circumstances; see Electricity Commission (2004).

on an allocation of national demand, using regional population forecasts for residential demand and regional GDP growth for commercial and industrial.

p0395 The forecasts are subjected to Monte Carlo analysis to provide an estimate of the forecast error, and before the figures are incorporated into the GEM they are passed through the Commission's hydrothermal dispatch model to estimate electricity demand per year, month, and island and to divide the load into blocks.[26]

p0430 With demand and generation opportunities thus exogenously determined,[27] the GEM uses programming techniques to design a least-cost generation portfolio to meet that demand. The model does not incorporate risk/return tradeoffs of the sort pioneered by Awerbuch [3] and Awerbuch and Berger [4], and it does not include in its output a future wholesale price path for each scenario, although such a path is implicit. Although the GEM does not calculate wholesale electricity prices, the Commission does use the model outputs to estimate the price levels necessary to achieve life-cycle revenue adequacy for the marginal generator(s) in each generation scenario. This does not, however, feed back to the demand block in Figure 14.9.

p0435 Figure 14.10 compares the Commission's demand forecasts with those of other modelers. Over the period to about 2040, the Commission's central projection is for demand to grow by 50–60 percent, an increase of 20,000–25,000 GWh over current annual generation. The projected annual growth rate of around 1.2 percent reflects linkage to expected GDP growth but with a steady exogenous improvement in efficiency. There are very wide uncertainty bands around this demand projection. At the lower end, both Webb and Clover [45] and MED [34] have estimated that major innovations on the demand side (high uptake of energy efficiency and distributed generation) could reduce required cumulative grid-connected generation growth to less than 40 percent. At the top end comes the high-demand scenario [45], in which increased electricity intensity of the economy drives projected demand up 70 percent over the three and a half decades.

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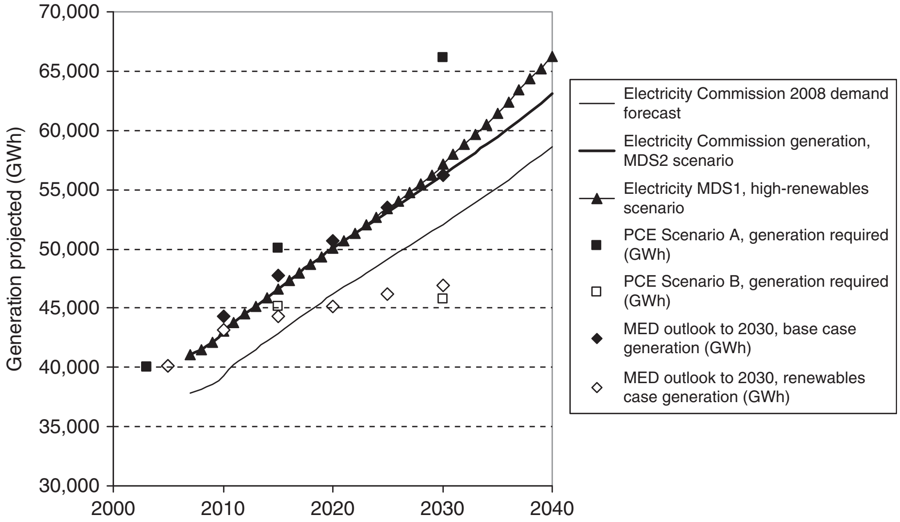
[26] The EC uses PSR Inc.'s SDDP software package for this task (www.psr-inc.com.br/sddp.asp). The package is designed to calculate the least-cost stochastic operating policy of a hydrothermal system, taking into account the following aspects:
Operational details of hydro plants
Detailed thermal plant modeling
Representation of spot markets and supply contracts
Hydrological uncertainty
Transmission network performance
Load variation

[27] The scenario headed "demand-side participation" in Table 14.3 is based on ad hoc exogenous adjustments to the projected demand path rather than endogenous feedback from price within the model.



f0055 **Figure 14.10** Projections of electricity demand and generation, 2000–2040. Source: Electricity Commission projections from the February 2008 demand forecast and June 2008 generation scenarios; MED scenarios from supporting data to Ministry of Economic Development [34]; Parliamentary Commissioner (PCE) projections from Webb and Clover [45].

p0440 The Electricity Commission's projected need for generation reaches 55,000 GWh by 2030 and 63,000 GWh by 2040, with the higher figure applying if there is a shift toward electricity away from other fuels (due, for example, to electrification of the transport vehicle fleet). Greenpeace ([20], p. 34, Figure 14.13, and p. 62, Appendix 2) similarly projects 59,000 GWh in 2040. Generation in Figure 14.10 must run above projected demand to allow for line losses and system constraints.

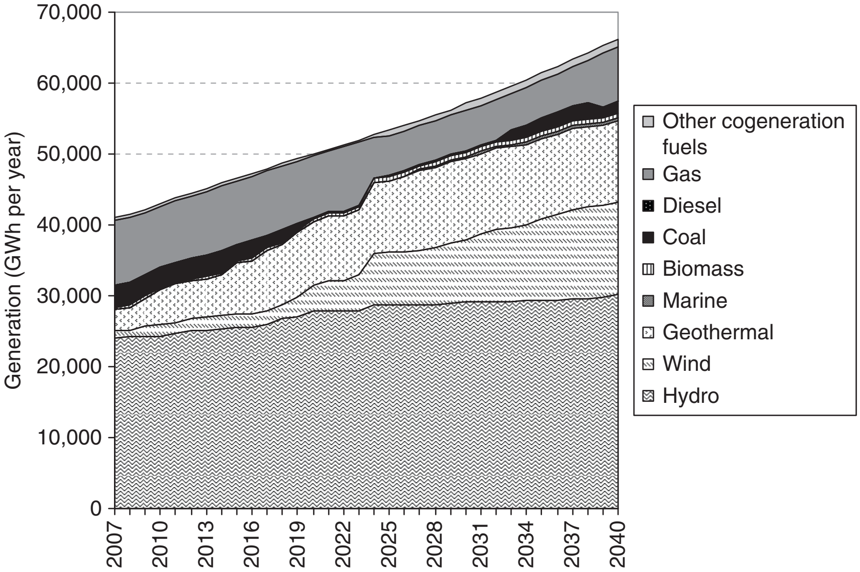
p0445 The least-cost capacity and generation to meet demand under the scenarios currently modeled by the Electricity Commission are summarized in Table 14.3 on the basis of results published in mid-2008 ([17], Chapter 6). The scenarios cover a range from the high-renewables "sustainable path" MDS1 to a low-renewables "high gas discovery" case, MDS5. Over the period to 2040, the renewables share exhibits a low of 61 percent and a high of 88 percent. This range reflects, at the low end, a minimum-renewables constraint imposed by already installed hydro, geothermal, and wind capacity and, at the high end, the need to allow for cogeneration and least-cost (thermal) backup supply. No scenario to date has incorporated the 90 percent renewables goal as a binding constraint, but it is clear that there are sharply rising costs to the system of driving fossil-fired generation below 10 percent of the total.

t0020 **Table 14.3** NZ Electricity Commission scenarios, June 2008

		MDS1: Sustainable Path	MDS2: South Island Surplus	MDS3: Medium Renewables	MDS4: Demand-Side Participation	MDS5: High Gas Discovery
2007	Installed capacity (MW)	8553	8553	8553	8553	8553
	Modeled generation GWh	41,079	41,069	43,067	41,075	43,074
2025	Total MW	12,488	12,481	10,899	10,934	10,934
	Portion of which is renewable (MW)	9935	9161	7317	7164	7084
	Renewable share (%)	*79.6*	*73.4*	*67.1*	*65.5*	*64.8*
	Total GWh	53,393	53,133	51,513	53,288	55,051
	Portion of which is renewable (GWh)	46,832	42,729	37,496	35,868	35,737
	Renewable share (%)	*87.7*	*80.4*	*72.8*	*67.3*	*64.9*

2030	Total MW	13,532	13,286	11,239	11,916	11,459
	Portion of which is renewable (MW)	10,899	9676	7692	7244	7285
	Renewable share (%)	*80.5*	*72.8*	*68.4*	*60.8*	*63.6*
	Total GWh	57,147	56,187	53,035	56,991	58,103
	Portion of which is renewable (GWh)	50,239	44,705	38,349	34,957	37,566
	Renewable share (%)	*87.9*	*79.6*	*72.3*	*61.3*	*64.7*
2040	Total MW	15,988	14,328	12,559	13,081	13,247
	Portion of which is renewable (MW)	12,500	9676	8467	8209	7855
	Renewable share (%)	*78.2*	*67.5*	*67.4*	*62.8*	*59.3*
	Total GWh	66,223	63,066	59,917	65,826	65,029
	Portion of which is renewable (GWh)	55,662	45,106	42,116	39,875	39,854
	Renewable share (%)	*84.1*	*71.5*	*70.3*	*60.6*	*61.3*

Source: Draft Statement of Opportunities, background tables downloaded from www.electricitycommission.govt.nz/opdev/transmis/soo/08gen-scenarios#generation-scenario-outlines [17].



f0060 **Figure 14.11** Generation by fuel, Electricity Commission scenario MDS1, 2007–2040.

Source: *Draft Statement of Opportunities*, background tables downloaded from www.electricitycommission.govt.nz/opdev/transmis/soo/08gen-scenarios#generation-scenario-outlines [17].

p0450 Figure 14.11 shows details of the Commission scenario that comes closest to the 90 percent target, namely scenario MDS1, Sustainable Path.[28] In this scenario the rapid expansion of wind and geothermal generation outpaces demand growth until the mid-2020s, when the renewables share reaches 88 percent. Renewables growth then slows while demand continues to rise, bringing coal back into the picture and reducing the renewables share back to 84 percent by 2040.

p0455 Inspection of the Commission's results highlights the importance of changes in, and the definition of, the denominator in calculating a "renewables share." Demand for electricity is affected by the same policy and relative-price forces

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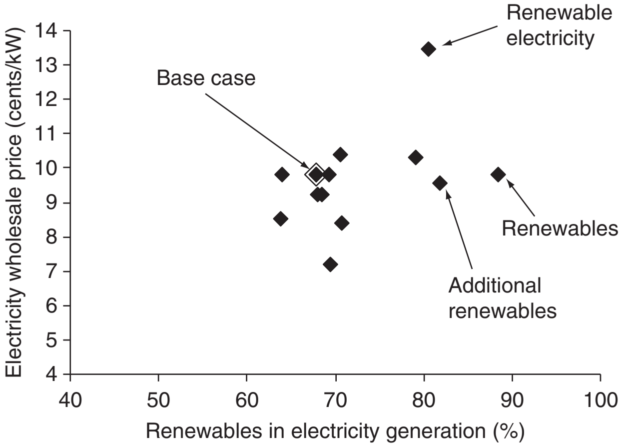
[28] The scenario "storybook" runs as follows: "New Zealand embarks on a path of sustainable electricity development and sector emissions reduction. Major existing thermal power stations close down and are replaced by renewable generation, including hydro, wind, and geothermal backed by thermal peakers for security of supply. Electric vehicle uptake is relatively rapid after 2020. New energy sources are brought onstream in the late 2020s and 2030s, including biomass, marine, and carbon capture and storage (CCS). Demand-side response (details not specified) helps to manage peak demand."

as those that drive the changing generation portfolio. Scenario MDS1 actually has higher demand in 2040 than the other scenarios in Table 14.2, partly because of the assumed shift to electric vehicles in the transport sector, with no change in the baseline energy-efficiency trend. In contrast, the High Gas Discovery scenario has lower electricity demand because of substitution of direct gas use for electricity. This simultaneous impact of modelers' assumptions on demand and supply makes 90 percent renewables a moving target. Unhelpfully vague specification of the target by the government to date has left this ambiguity unresolved.

s0060 14.5.2 MINISTRY OF ECONOMIC DEVELOPMENT MODELING WORK

p0460 The Electricity Commission's published results do not enable construction of renewables/price reliability contours along the lines of Figure 14.5, but work by the Ministry of Economic Development [34] has produced wholesale price estimates for a range of 14 supply/demand scenarios out to 2030, with solutions at 5-year intervals. These scenarios were designed to test a range of alternative assumptions about technological progress, feasibility of adopting identified renewable resources for electricity generation, and adoption of energy-efficiency measures on the demand side of the market.

p0465 Figure 14.12 (with the same axes as Figure 14.5) plots the wholesale price of electricity in each of the 14 scenarios against the proportion of renewables in



f0065 **Figure 14.12** Renewables share and wholesale price: MED 2006 scenarios at 2025 [34].
Source: Calculated from Ministry of Economic Development [34].

total electricity generated. The business-as-usual base case has only 69 percent renewables in 2025, with a wholesale price of 9.8¢/kWh. Three of the alternative scenarios reach a renewables share of over 80 percent, and one has a share of 88 percent, with a price equal to the base case. If the points in Figure 14.12 are thought of as indicating where the cost/renewables contours run for New Zealand, then apart from one conspicuous outlier they suggest a remarkably flat curve up to the vicinity of 90 percent renewables. (The Ministry's modeling, however, may not fully incorporate the external cost of the ancillary backup services required to integrate a large volume of renewable generation into grid supply.)

p0470 Three of the MED scenarios in Figure 14.12 achieve over 80 percent of electricity generated from renewables: In Figure 14.12 they are labeled Renewables, Renewable Electricity, and Additional Renewable Electricity ([34], pp. 130–131, 99–102, and 102–104, respectively). The first and third of these have the same wholesale price as the 69 percent renewable base case, which seems to hint at opportunities to shift the generation portfolio toward 90 percent renewables by 2025, with little or no consequent increase in the wholesale electricity price—the renewability/price contours appear to be flat or only shallowly sloped across these scenarios.

p0475 The prominent high-cost outlier Renewable Electricity in Figure 14.12 is not a like-with-like comparison relative to the other observations and has to be interpreted with care. For this scenario, the modelers assumed that policymakers intervene directly to reduce the use of fossil fuels in electricity, with no action in other energy sectors—an approach similar in some respects to the now abandoned legislated moratorium. Under this assumption, no new coal-fired plant is built, the sole existing coal-fired plant is closed in 2014, and no new gas-fired plant is built, although existing gas-fired generation remains in operation. A steep rise in wholesale price is then required to bring in large volumes of new high-cost hydro and wind generation, and some high-cost geothermal,[29] to meet unrestrained demand growth. This scenario certainly raises the renewables share of generation but at relatively high cost.

p0480 The lower-cost Additional Renewable Electricity scenario assumes relaxation of planning and land-use constraints on the exploitation of renewable resources, allowing the model to build a large amount of moderate-cost

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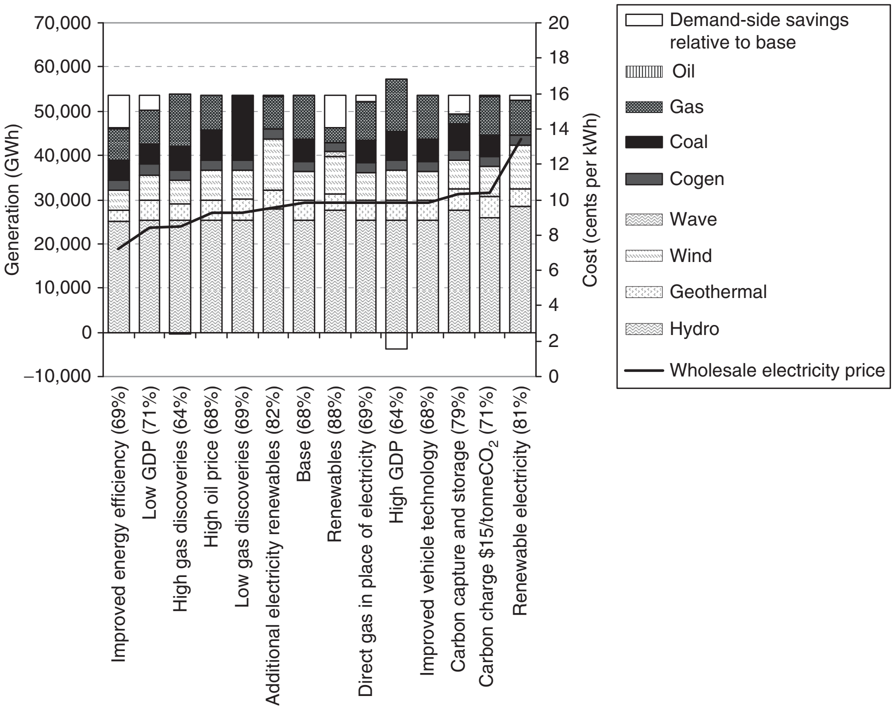
[29] The treatment of geothermal in the MED scenarios is problematic, since it is given no credit for its ability to provide reliable baseload. Instead, the modelers assumed that it would be crowded out of the dispatch order for much of the time by must-run hydro and wind, on the basis that the latter have lower short-run marginal costs ([34], p. 100). In fact, it is likely that geothermal would be bid in at a zero offer price designed to undercut wind and hydro.

renewable generation that would (in the modelers' judgment) otherwise be ruled out by collateral damage to the environment. The renewables share then rises by 12 percentage points relative to the base case, with effectively no increase in wholesale price (marginal cost). Relative to the Renewable Electricity case, the model results suggest that overcoming resource consent hurdles could bring the wholesale price down by a full 4¢/kWh at the 2025 horizon, a reduction of 28 percent. Since the New Zealand government has a reserve power under planning law to "call in" selected projects seeking planning consent, there exists a straightforward policy instrument that could effectively eliminate the financial cost of a drive to renewables if the MED scenarios are taken as accurate.

p0485 The results from the Renewables scenario highlight the shortcomings of any policy that is limited simply to banning new fossil-fuel generation in electricity or overriding commercial merit-order dispatch, with no supportive price-based measures to promote renewables and energy-efficiency economywide, incentivize demand-side savings and response, and place prices on environmental externalities. In this third scenario, the MED modelers assumed that resource consents remain constrained as in the Renewable Electricity scenario, but they allowed for exogenous energy-efficiency improvements on the demand side and the installation of 750 MW of marine wave-power generation by 2025 at a cost of 10.2¢/kWh. The results are dramatic: Energy-efficiency gains reduce the amount of generation required in 2025 by over 7000 GWh (13 percent) so that even though total renewables generation is 2000–3000 GWh lower than in the other two renewable scenarios, the reduced demand enables fossil fuels to be squeezed to the margin of supply while keeping the wholesale price down, equal to the business-as-usual base case.

p0490 The demand side of the market thus emerges as crucial to securing a swing toward 90 percent renewables at low cost without sacrificing the competing environmental and social values protected by the planning laws. Even with demand reductions, however, the 2006 MED results suggested that costs turn up sharply at around 90 percent renewables, with an incompressible residual tranche of fossil-fired capacity.

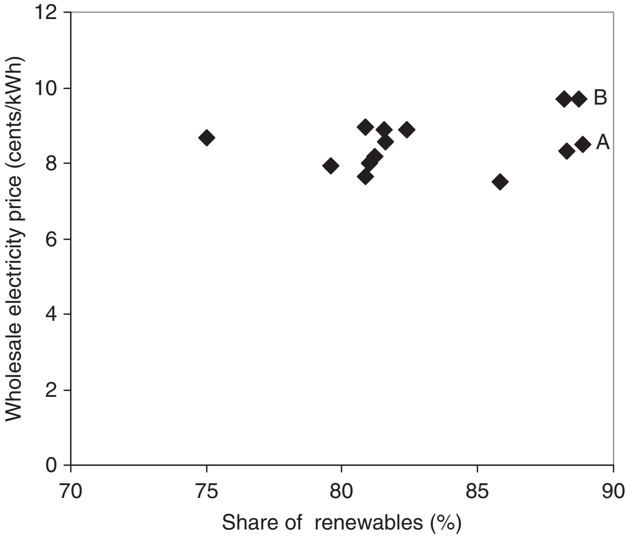
p0495 In 2007, MED and the Electricity Commission combined their models to evaluate a further set of policy scenarios designed to nudge the economy toward renewables [36]. Options explored included carbon taxes ranging from $15–50/tonne, outright bans on fossil-fuel generation, and subsidies to renewables funded from consumers or from general taxation. Again, no scenario reached the 90 percent target (the highest was 88 percent). The 14 scenarios are plotted in Figure 14.13 in ascending order of wholesale electricity price. The height of each bar corresponds to the amount of generation required from grid-connected generation in each case. The Improved Energy



f0070 **Figure 14.13** MED 2007 generation scenarios for 2025, ranked in order of wholesale electricity price.
Source: Calculated from Ministry of Economic Development [36].

Efficiency case at the left side of the diagram has both lowest generation and lowest price. The potential importance of demand-side savings in holding down the cost of a renewables-focused policy is clearly apparent, but this finding has not been picked up in the 2008 Electricity Commission work discussed earlier.

p0500 Figure 14.14 uses the results from MED [35] to indicate the location of the renewability/price contours. Renewables shares of generation ranging from 75 percent to nearly 90 percent turn out to be compatible with a wholesale electricity price only slightly above the 68 percent renewable base case. At the high-renewables end of the range, the difference between a scenario that achieves 88 percent renewable generation by subsidies to renewables and one that achieves the same target by a $50/tonne emissions charge on generators (Points A and B, respectively, in Figure 14.14) is 1.2¢/kWh, implying that the level of subsidy required to meet a 90 percent target could be less than 10 percent of the wholesale price.



f0075 **Figure 14.14** Renewables share and wholesale price, MED 2007 scenarios at 2025.

Source: Calculated from supporting data tables to MED 2007, downloaded from www.med.govt.nz/templates/MultipageDocumentTOC____31983.aspx [36]

p0505 In short, the evidence from recent modeling studies points to a nearly flat supply curve of renewable generation for New Zealand up very close to 90 percent. This in turn means that implementation of price-based instruments such as a carbon tax should be expected to elicit a high-elasticity response from the electricity supply side in terms of the composition of new investment, bringing the 90 percent target within easy reach.

s0065 14.5.3 THE LONG-RUN RENEWABLES SUPPLY CURVE

p0510 The Electricity Commission's preparation of its generation opportunities database turned up an unexpected wealth of opportunities—especially in wind resources, which are potentially in unlimited supply relative to national demand.[30] The Commission has identified new renewable projects totaling over 6400 MW at a long-run marginal cost of NZ$130/MWh or less, plus a further 13,000-plus MW of renewables that are either somewhat higher cost or cost-competitive but subject to other constraints in early development (see Table 14.4).

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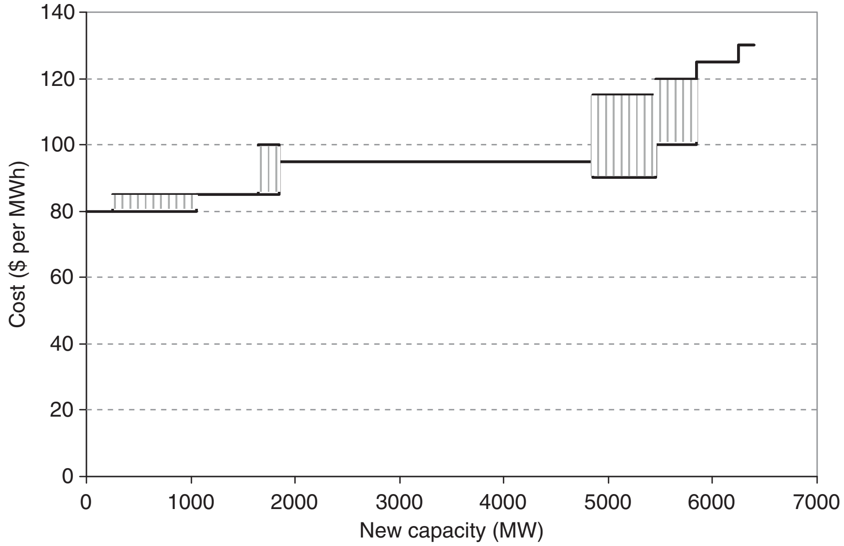
[30] Details of the database and the model are posted on the Commission website at www.electricitycommission.govt.nz/opdev/transmis/soo/08gen-scenarios/?searchterm = TTER and www.electricitycommission.govt.nz/opdev/transmis/soo

t0025 **Table 14.4** Scope of feasible renewable projects

$/MWh	80	80–85	85	85–100	95	90–115	100–120	125	130	Total	Other	Total potential
Geothermal	250–300	—	400	—	—	—	—	—	—	650–700	56–106	756
Wind	—	800	—	—	3000	—	—	—	—	3800	12,590	16,390
Hydro	—	—	200	200		600	400	—	—	1400	537	1,937
Biomass cogen	—	—	—	—	—	—	—	—	150	150	—	150
Marine	—	—	—	—	—	—	—	400	—	400	—	300
Total MW	250–300	800	600	200	3000	600	400	400	150	6400–6450	13,183–13,233	19,533

Source: Electricity Commission ([16], pp. 65–80), and ([17], pp. 93–95); SSG, 2008.



f0080 **Figure 14.15** Estimated renewables supply curve from Electricity Commission database.
Source: Electricity Commission ([16], pp. 65–80), and ([17], pp. 93–95); SSG, 2008.

p0515 Figure 14.15 constructs an approximate supply curve from this data for the 6400 MW that has been provisionally costed by the Commission. Six thousand MW of new renewable capacity is estimated to have life-cycle (long-run) costs of NZ$120/MWh or less; 5000 MW of this is costed below $100/MWh. With very large volumes of wind potential still uncosted, the renewability supply curve appears likely to continue to flatten in the future.

p0520 Gas and coal plants are estimated to have long-run marginal costs competitive with most of the renewables in Figure 14.15 only if gas is priced at $7/GJ (below the LNG benchmark) and if there is no carbon charge. A carbon charge of NZ$30/tonne CO_2 would push thermal generation to or above the top of the range in the chart, making the full 6400 MW of listed renewable generation competitive on cost and relegating thermal to a support role as peaking plant and dry-year backup.

p0525 The conclusion is that New Zealand has sufficient hydro, geothermal, and wind resources to bring the 90 percent renewables target within easy reach at little if any cost penalty relative to fossil fuels, once carbon-emission externalities are priced in. The problem to be confronted in reaching the 90 percent target will not, therefore, be limited resource endowment. Rather, it will be institutional barriers and the overhang of legacy thermal capacity.

p0530 There is an apparently incompressible slice of nonrenewable generation associated with cogeneration, sunk-cost existing capacity, and reliability constraints in the absence of a responsive demand side, which does not fall below 10 percent in any of the Electricity Commission's scenarios to date. Ironically, across-the-board gains in energy efficiency and consequently lower demand growth could make it more, rather than less, difficult to achieve 90 percent renewables, because reduced need for new large-scale generation plants to meet demand growth means a larger share of legacy plants in the portfolio. To pursue the 90 percent target with radically reduced demand growth, policymakers would have to force the decommissioning of existing thermal capacity.

s0070 14.6 Evaluating the current policy

s0075 14.6.1 SUPPLY-SIDE BIAS?

p0535 The Electricity Commission is charged "to ensure electricity is produced and delivered to all consumers in an efficient, fair, reliable and environmentally sustainable manner," subject to a government policy that states:

> *... [e]lectricity efficiency and demand-side management help reduce demand for electricity, thereby reducing pressure on prices, scarce resources and the environment. The Commission should ensure that it gives full consideration to the contribution of the demand side as well as the supply side in meeting the Government's electricity objectives. ...*[31]

p0540 The Commission has in practice been almost entirely preoccupied with the supply side (large-scale remote generators connected to the transmission grid), and this has strongly colored its modeling work. A recent Commission discussion of "nontransmission alternatives" ([16], pp. 39–41) contains no mention of downstream and demand-side options that might relieve grid constraints or strand grid-connected generators. This is particularly significant given the explicit instructions to the Commission in the most recent Government Policy Statement that modeling work should "enable identification of potential opportunities for ... transmission alternatives (notably investment in local generation, demand-side management and distribution network augmentation)."[32]

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[31] Government Policy Statement on Electricity Governance, updated to May 2008, www.med.govt.nz/templates/MultipageDocumentPage____37639.aspx, paragraph 34.

[32] Government Policy Statement on Electricity Governance, updated to May 2008, www.med.govt.nz/templates/MultipageDocumentPage____37639.aspx, paragraph 89.

p0545 The dominance of incumbent-generator concerns in the work of the Electricity Commission has been reinforced by the reluctance of the New Zealand government to tackle barriers to entry facing distributed generation and decentralized demand-side response [6]. This means that the 90 percent renewables target has to date been conceived of by policymakers almost exclusively in terms of the construction of new large-scale grid-connected generating plants.

p0550 Insofar as price-responsive demand-side options can be brought into the market with real-time price incentives, there is good evidence from modeling work internationally that they are often more cost-effective than, for example, installation of quick-response supply-side options such as open-cycle gas turbines. The GreenNet modeling project carried out for the European Commission found, for example, that demand response could reduce the system cost of maintaining capacity margins in a high-wind-penetration scenario to as little as 25 percent of the cost of the thermal-generation equivalent (Figure 6.5, [2], p. 18; see also [25, 28]).

p0555 This suggests that small islanded systems should be especially eager to maximize demand-side flexibility and load management. Ironically, although demand-side measures were willingly developed in New Zealand half a century ago, they have been shut out of the new "deregulated" market by a complex rulebook drafted by and for the dominant large generation companies, combined with the absence of any pro-competitive regulations requiring retailers to post feed-in tariffs or make other provision for small independent suppliers to reach customers.

p0560 Looking back to Figure 14.10, there is a wide gap between the mainstream projected demand path and the low-demand scenarios of some analysts, suggesting that implementation of demand-side and distributed-generation options might cause substantial stranding of grid-connected generation investment. That prospect will provide a strong incentive for the incumbent generators and network operators to oppose policy initiatives to decentralize the market.

s0080 14.6.2 GAPS IN THE CURRENT POLICY FRAMEWORK

p0565 Having articulated its strategic goal of achieving 90 percent renewable generation, the New Zealand government had not, as of 2008, settled on a fully credible set of policy instruments to pursue that goal. In particular, market-based regulatory instruments have been missing. Neither the U.K. adoption of regulated renewable quotas for electricity retailers (Cornwall, Chapter 15 in this volume) nor the Australian tradeable renewable quotas scheme [37] has struck any chord with New Zealand policymakers. Nor is there serious discussion of demand-side measures such as real-time pricing and net metering, notwithstanding the potential importance of real-time demand-side response as a means of coping with intermittency of wind and wave generation [28].

p0570 For a New Zealand generator that anticipates that the previous government's 90 percent goal may be abandoned and a lower renewables share allowed in the future, it remains rational to proceed with the planning of fossil-fuel generation projects to the point of final decision on major expenditure. A considerable lead time for major projects is required because of the need to secure planning consents for land use and emissions and to complete design work and possibly install infrastructure for the new plant. The government's 2007 announcement of its moratorium on construction of new baseload thermal plants did not trigger abandonment of any existing plans to build new nonrenewable generators.

p0575 Two major generators (Contact Energy at Otahuhu and Genesis Energy at Huntly) have fossil-fired sites with planning consent already in place and are in a position to build at quite short notice. Genesis Energy, meantime, is pressing ahead to secure planning consents for a new 400 MW CCGT plant at Rodney, near Auckland.

p0580 In the face of this direct challenge to its credibility, the Labour government appeared weak. The State-Owned Enterprises Minister sent a letter to all state-owned generators in October 2007 [29], informing them of the moratorium and asking to be kept informed of their plans, but the letter made it clear that the minister would not use his powers to give direction under the State-Owned Enterprises Act of 1986, leaving the companies effectively free to proceed. (Contact Energy is privately owned and not subject even to this mild level of influence.) The test of whether the newly elected National government will grant an exemption for Genesis Energy's Rodney project is still to come.

s0085 14.7 Conclusion

p0585 New Zealand remains some distance from full policy commitment to a renewable future, but the direction in which market forces will push the country's electricity sector seems increasingly well defined and can be expected to deliver something close to the 90 percent target with minimal policy activism, provided the emissions tax proceeds.

p0590 This is a reversal of the dominant trend of the past half-century. At the time when many countries began to move away from dependence on fossil fuels under the spur of high oil prices in the 1970s, New Zealand embarked on a deliberate program of raising the fossil-fuel intensity of its economy to take advantage of its windfall of domestic natural gas. Only as gas prices began to rise from 2003 with depletion of the Maui field, accompanied by an upward trend in the electricity wholesale price, have the economics of geothermal become attractive again, while the rapidly falling cost of wind generation has triggered a wind-farm boom.

p0595 The New Zealand government's 2008 approach of placing a blanket restriction on the construction of new baseload fossil-fired capacity is likely to leave sufficient legacy thermal capacity in place to supply more than 10 percent of total generation in 2025, unless some further restriction is placed on the ability of thermal plants to bid for dispatch. To some extent the planned carbon tax will provide such a restriction, but the possibility of a need for more direct regulatory restraint on the operation of thermal plants cannot be ruled out if the 90 percent goal is seriously pursued.

p0600 Long suppressed by policymakers and the dominant generators, the potential for small-scale distributed generation and an active, responsive demand side might become a problem rather than a support for the 90 percent target if central generation is overbuilt and then stranded by an eventual demand-side renaissance. Policymakers would be well advised to take proper stock of their demand-side options earlier rather than later.

p0605 Turning to the wider global picture, New Zealand combines a number of characteristics that are not shared by the majority of the countries covered in this book. It is an island system without external backup, which means that its domestic electricity price is set in isolation from wider markets. It has a century-long history of a dominant role for renewables (hydro and geothermal) in its generation mix; the strong trend toward greater reliance on fossil fuels since 1970 now appears as an aberration that is already being reversed by relative-price trends in fuels and technology. The likely dominant renewable technologies for the next generation of investment—geothermal and wind—are well proven and mature, and the New Zealand resource endowment is known to be on a scale that makes a 90 percent renewables target entirely realistic. The cost of bringing in these renewables appears to be little if at all higher than the cost of fossil-fuel generation, especially in the context of a carbon charge and with the prospect of increased urgency of climate-change policy in the coming decades.

p0610 For other countries, high-renewables targets in electricity are probably feasible only at much higher cost. From Figure 14.6 it would appear that for most OECD countries, nuclear power offers a more likely path toward carbon-free generation than the renewables that are at the heart of New Zealand's determinedly nonnuclear future. In this respect one lesson to be learned from New Zealand (and Iceland) is that to escape from both nuclear and fossil fuels at reasonable cost requires an unusual combination of low population and an abundant natural resource endowment—or technological breakthroughs on a truly epochal scale.

p0615 For New Zealand, probably the most important lesson yet to be learned from the rest of the OECD is the importance of real-time demand-side response and distributed generation in a modern electricity system. Deregulation and corporatization of New Zealand's electricity sector since 1987 have left untouched the centralized engineering solutions that served the country well from the 1950s to the 1970s. The current market institutions built around that structure present obstacles to the widespread adoption of a 21st-century smart grid and small-scale-generation technology. A substantial regulatory agenda remains to be tackled.

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