Chapter 7
Restructuring the New Zealand Electricity Sector 1984–2005

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Summary

This chapter describes New Zealand's failure over two decades of reform to establish a viable industry self-governance framework, and the parallel failure to achieve restraint on monopoly profits by means of light-handed regulation. Starting from a classic publicly owned monopoly of generation, transmission, distribution, and retailing, New Zealand corporatized all levels of the supply chain, separated lines businesses from generation and retail, removed retail franchises, and broke up the monopoly generator into five companies, two of them privately owned. These measures were insufficient to achieve competitive outcomes in the absence of hands-on regulation. Generators integrated vertically by takeover of retailers, and the resulting retail oligopoly erected an effective barrier to entry by withholding affiliated generators' capacity from the very thin market for hedge contacts. Grid pricing and contract provisions foreclosed demand-side innovation and distributed generation. Distribution lines businesses ramped up mark-ups from 30% to 70% without any regulatory restraint, and were allowed to revalue their assets to underwrite the new high margins. Faced with failure of the original design, the Government in 2003 established a new industry regulator and invested in new state-owned thermal generation to plug the country's yawning gap in reserve capacity.

7.1. Background

New Zealand is a country of 4-million people spread across an area the size of Italy or the UK. From south to north the country is over 2000 kilometers in length, with the two main islands separated by the 30-kilometer-wide Cook Strait. The largest city (and major electricity load center) is Auckland, with 1.3 million inhabitants.

Electrification began in the late 19th century, when local authorities and private entrepreneurs constructed small generation facilities to serve local markets.[1] Following the First World War the Government embarked on the construction of a set of large state-owned

[1] A detailed history of the New Zealand electricity industry is Martin (1998). See also Rennie (1988), Jackson (1988, 1990).

hydroelectric plants on major rivers, linked by a transmission grid from which power was taken off by local-government distribution and retail companies (Electrical Supply Authorities, ESAs), each with a territorial monopoly franchise.

ESAs supplied a bundled service, comprising low-voltage distribution networks, the retailing of electricity to final customers, and supply and servicing of household electrical appliances. In the 1950s, when major new investments in generation plant struggled to keep pace with demand growth and blackouts were a common occurrence, most households were placed on ripple control to switch off water heaters at times of peak demand.[2]

The state-owned generation and transmission system built up from the 1920s displaced most locally owned generating plant, and standardized the countrywide retail supply voltage at 220/240 volts at a frequency of 50 MHz (matching the UK settings). For the next half-century, electricity generation and transmission remained a state-owned monopoly, while distribution and retail remained franchised, publicly owned, local monopolies.

Regulation in this setting was redundant, since both central and local government were democratically accountable, and operated the electricity supply system with social, rather than commercial, goals. Prices were set to achieve break even, in cash flow terms, over the long run. Financial disclosure, in terms of the cash flow model used for much of the public sector, was comprehensive, with detailed accounts for all levels of the system published annually.[3] Asset values were recorded in historic-cost terms without adjustment for inflation, and were also lowered by the common practice of expensing day-to-day small-scale acquisition of capital equipment.

Initially the two main islands had separate electricity grids, but there was an obvious mismatch between the abundant hydro resources of the South Island and the concentration of load in the North Island, particularly in Auckland. In 1965 a high-voltage direct current (HVDC) cable across Cook Strait connected the two systems together, allowing power from large hydroelectric developments in the South Island – particularly Benmore (540 MW) and Roxburgh (320 MW), on the Waitaki and Clutha Rivers, respectively – to be sent north. Thereafter the entire national generation and transmission system developed as a single integrated whole. The North Island accounts for around two-thirds of national demand but only one-third of generating capacity; the South Island has two-thirds of generation capacity but only one-third of demand.[4]

New Zealand's annual electricity consumption is currently around 36,000 GWh, supplied from a system with 8500 MW of installed capacity. The 50% capacity utilization ratio reflects

[2] Ironically, this almost universal penetration of simple demand-management technology in the period of public-sector monopoly has been allowed to slide away in the era of "market reforms" since 1987, as large commercially oriented firms on the supply side have welcomed demand-driven price spikes which they could take directly to their bottom lines.

[3] The Minister in charge of the New Zealand Electricity Department (NZED) tabled a full annual report in Parliament each year. All ESA financial and operational data was published annually from the early 1960s under the cumbersome title *Annual Statistics in Relation to Electric Power Development and Operation for the Year Ended 31 March*. The latter publication rapidly reduced its coverage in the early 1990s and was discontinued in 1994. Its successor, the company-by-company regulatory information disclosure from 1994 on, was both less informative and inconsistent from company to company, which means that public monitoring of performance has been more difficult after the reforms than before.

[4] The mismatch between the two islands would have been greater still had it not been for the establishment in the 1960s of the large Comalco aluminium smelter at Bluff in the far south, which by itself comprises about 17% of national demand and provides the principal market for the Manapouri hydro scheme, the country's largest with capacity of 710 MW (upgraded from 585 MW in 2002).

Table 7.1. Trends 1965–2004.

	Total installed generating capacity (MW)	Peak load (MW)	Total consumption (GWh)	Total sales revenue ($m)	Average final price (c/kWh)	Real average price, c/kWh at March 2004 prices
1965	2336	2048	8189	90.0	1.10	14.56
1970	3683	2690	11,069	143.3	1.29	13.79
1975	4784	3391	16,272	196.4	1.21	8.41
1980	5860	3677	19,040	681.5	3.58	12.58
1985	6988	4642	23,994	1190.4	4.96	9.58
1990	7067	5122	27,309	2144.2	7.85	10.64
1995	7910	5240	29,925	2490.2	8.32	10.23
2000	8845	5830	32,735	2888.2	8.82	10.36
2004	8515	6090	35,795	4014.5	11.22	11.85

Sources: Installed capacity from *Annual Electricity Statistics* and *Energy Data File* for years shown. Consumption, revenue, and prices from *Energy Data File* January 2005, p. 126 Table G.12, p. 134 Table I.1, and p. 135 Table I.2. Real average price 1965–1975 derived using CPI.

the fact that two-thirds of supply comes from hydro generators which are designed to run at a low load factor, combined with the existence at the margin of some high-cost thermal generating capacity which is operated for only part of the year. System-wide capacity utilization has risen steadily over recent decades, reaching 40% in the mid-1980s and approaching 50% in the mid-2000s.

Table 7.1 sets out key statistics of capacity, consumption, revenue, and final price from 1965 to 2004. This period includes the last two decades of the old system, the "reform" years from 1986 to 1998, and recent experience with the restructured system.

Figure 7.1 shows installed capacity and peak load since 1964. Capacity growth has proceeded in a stop-start fashion, attributable partly to the lumpiness of generation projects, partly to swings in policy, and partly to commercial decisions since corporatization. In the mid-1960s the momentum of the hydro construction program was at last outstripping demand growth after a decade of stress in the 1950s. System peak load in the mid-1960s was around 90% of installed capacity, but with hydro capacity expanding 8.5% per year until the mid-1970s, the ratio was brought down to below 70% by the late 1970s, and has remained around that level for the subsequent three decades. Peak load growth, which caused concern among power planners in the 1970s and 1980s, slowed down from the late 1980s; the central problem since 1990 has been maintaining supply in dry years.

Figure 7.1 shows also a slackening in the pace of new construction following deregulation in the early 1990s, and the impact of the periodic decommissioning by the new owners of commercially unattractive dry-year-reserve thermal plant, which has left the system increasingly exposed to climatic fluctuations.

The map of the main high-tension transmission grid in Figure 7.2[5] shows the location of the two main bottlenecks in the transmission system: the HVDC link from Benmore to Haywards, and the central North Island between Haywards and Otahuhu. For the purpose of understanding the basic economics of the network, the nodal spot prices at these three key measurement points suffice to put a price on the two key transmission constraints, which cause market segmentation into three main regions at times of stress (Videbeck, 2004).

[5] For a detailed map of the entire grid showing all nodes, see http://www.transpower.co.nz/?id=4631

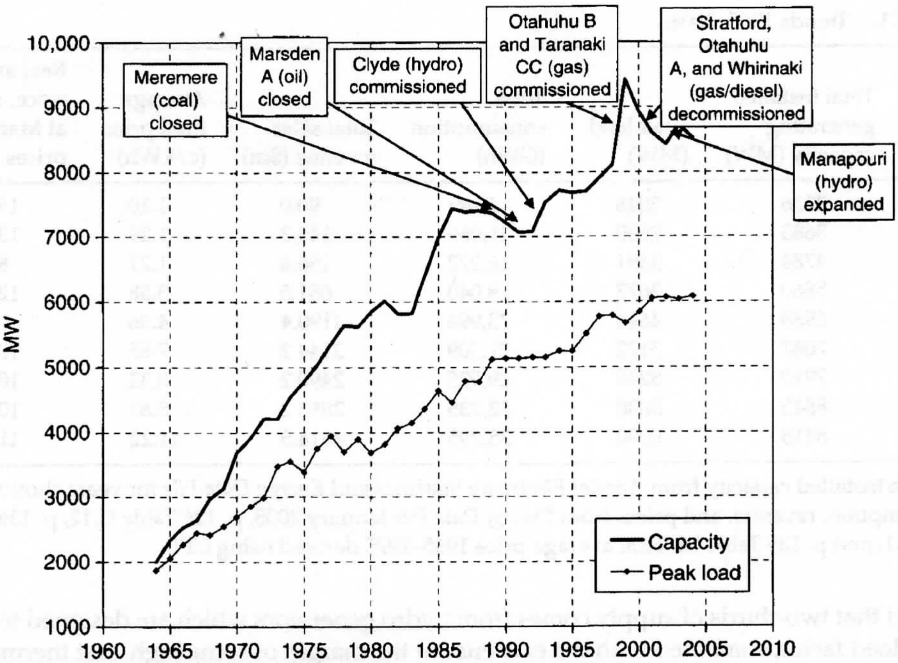

Fig. 7.1. Generating capacity and peak load, 1964–2004. *Source*: Data compiled from *Annual Statistics in Relation to Electric Power Operation in New Zealand* 1965–1993, and from *Energy Data File* for years 1995–2004.

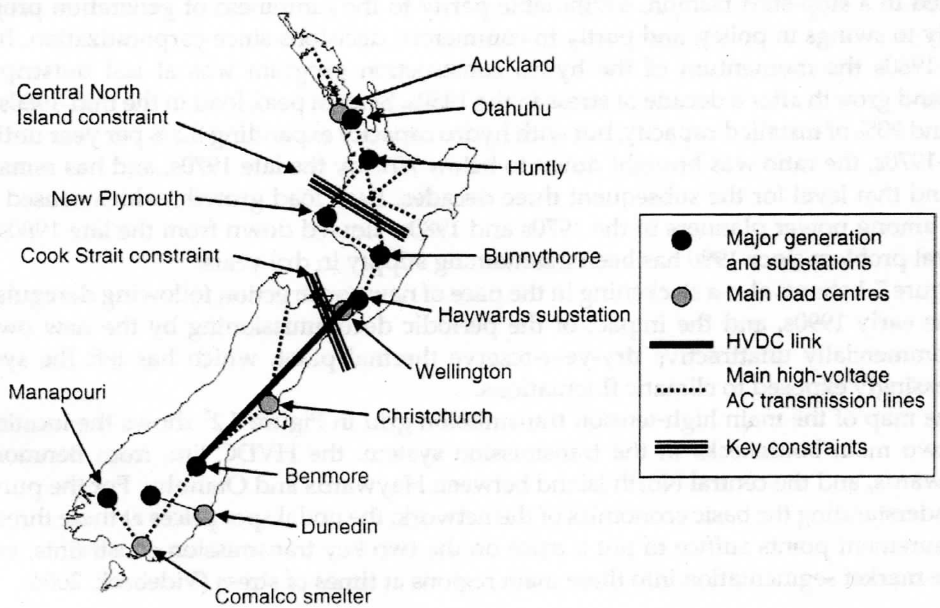

Fig. 7.2. Major transmission lines, showing location of the two main constraints.

7.2. Supply/Demand Balance

Three key features of the electricity supply industry (ESI) in New Zealand have to be borne in mind when considering options for restructuring:

- Most generation (60–70%) is from renewable sources (hydro and geothermal).
- The hydro lakes are located mostly in steeply sloping river valleys and provide storage capacity for only a few weeks, which means that unusually dry climatic conditions quickly translate into reduced supply. Similarly, unusually high inflows of water must be utilized within quite a short time horizon, or else be spilled to waste.
- New Zealand is a stand-alone closed market, with no means of importing or exporting electricity. A supply shortage, therefore, results directly in demand rationing and/or price spikes, while excess potential supply can be neither stored beyond a short period, nor sold in external markets.

Prior to the restructuring, which began in the mid-1980s, New Zealand's generation plants were operated on the basis of control procedures that equated the shadow value of stored water to the short-run marginal cost of thermal generation. So long as river flows were adequate, hydro plant could be operated as baseload, with thermal peaking plant utilized in periods when demand exceeded the supply available from optimal utilization of water. The usual roles of hydro and thermal generation were thus reversed. However, hydro also performed (and still performs) the very short-run task of frequency control, via the Maraetai II generating station on the Waikato River.[6]

Until the early 1990s the state-owned monopoly generator and grid operator, the New Zealand Electricity Division (NZED, later the Electricity Corporation of New Zealand, ECNZ), carried out this optimization exercise internally, and scheduled its various generation facilities to optimize the utilization of water by attaching a shadow value to hydro generation to reflect both foregone opportunities to utilize water in later periods, and planners' judgments regarding future hydrological conditions. If lakes were full and high inflows were expected, hydro plant would be operated at capacity. If lake levels were low and a dry year was anticipated, water would be held back and more thermal plant brought online to fill the resulting gap in supply.

Unchallenged control of a balanced portfolio of generation options enabled NZED to reap economies of scope as well as scale, because of its ability to internalize spillover externalities amongst various generation technologies. In particular, the explicit balancing of hydro and thermal generation options to maximize year-round operating efficiency of the system as a whole was the key to the ability of NZED to provide a very high level of security, and quality, of supply across the entire country, even in the face of climatic variability (mainly uncertainty about rainfall and, hence, river flows).

NZED's explicitly forward-looking scheduling and planning procedures took advantage of this heterogeneity of its generation assets to supply wholesale power at an average-cost price (the bulk supply tariff, BST), with operating surpluses from hydro generation used to cross-subsidize the high-operating-cost thermal firming plant. From 1957 on, the BST

[6]The two generating stations attached to the Maraetai dam have a total capacity of 360 MW, well in excess of the capacity needed to utilize run-of-the-river flow. The second station (excess capacity) installed in 1971 was designed to provide frequency control for the national grid, and has metering and control equipment to detect and offset load fluctuations. See http://www.mightyriverpower.co.nz/Generation/AboutUs/HydroStations/Maraetai/Default.aspx

included a levy on consumers to fund new investment in generation and transmission as well as covering operating costs of the system. This cash-in-advance approach meant that whenever a major new round of investment was undertaken, the BST would be raised to provide the necessary funds in advance. Consumers were immediately conscious of the resulting rise in retail charges, which meant that electricity investment was always politically sensitive.

The managers of the system were motivated both by the quest for engineering efficiency, and by this political sensitivity, since NZED and its controlling Minister would carry the political blame for any supply outages. There were strong incentives to invest ahead of demand,[7] keeping a substantial safety margin in both generation and transmission; but there was a countervailing possibility of political backlash if excessive investment programs drove up the BST, and hence the price to consumers, unduly. In the late 1970s and early 1980s the system's planners maintained a wide margin of excess capacity and embarked on a major round of large hydro construction, which exposed NZED to criticism that it was over-investing relative to a socially optimal benchmark.

Such criticism was particularly acute in the mid-1980s as it became apparent that the momentum of the ongoing hydro construction program had carried NZED into a series of large hydro projects (Tongariro, Rangipo, and Clyde) whose unit costs were orders of magnitude higher than the BST. As it became generally accepted that the long-run marginal cost (LRMC) of new generation had risen sharply relative to the average cost of supply, a noisy debate ensued between advocates of immediate increases in the wholesale electricity price to signal future costs, and supporters of continuing with the long-established average-cost pricing approach. This pricing debate is discussed further below.

7.3. Restructuring the Sector

7.3.1. *First steps*

There was a sea change in New Zealand economic policy in the mid-1980s, as neoliberal economic doctrines (largely copied from the UK) were adopted by key ministers in the Labor Government elected in mid-1984, resulting in radical changes to all state-owned operations, including electricity.

Initially the aim was to ensure that state-owned monopolies increased their profitability by raising their prices to contribute to reducing the government's budget deficit (Ministry of Energy Financial Objectives and Pricing Review Team, 1984). A second goal, initially also motivated by revenue maximization rather than structural reform, was to raise the economic efficiency of state-owned operations by converting them into profit-oriented commercial corporate organizations. Linked to this was a desire to curb what were perceived by the New Zealand Treasury at the time as excessive investments in new capacity, which officials regarded as a drain on scarce government resources.

In 1986 the Labor Government announced its decision to reform publicly owned trading activities, including the generation and transmission sectors of the electricity industry,[8] and a State-Owned Enterprises Act was passed to govern the process of corporatization.

[7] As Chapter 1 notes, many countries have had difficulty with investment incentives in the new restructured environment.

[8] For a detailed official history of the reforms summarized here, see *Chronology of the New Zealand Electricity Reform*, at http://www.med.govt.nz/ers/electric/chronology/index.html

In April 1987, the NZED was converted into the ECNZ and a private-sector entrepreneur was recruited to head the new board. The following year the operation of the transmission grid was transferred to a new ECNZ subsidiary, Transpower Ltd, as a first step toward separation of generation from transmission. The expectation of key policy-makers was that the generation assets of ECNZ would in due course be privatized, while the grid would be separated off under a governance arrangement that would restrain its exercise of market power.

In December 1987 the Government set up an Electricity Task Force to advise on the new industry structure and regulatory requirements. The Task Force reported in September 1989, with three key recommendations: establishment of a competitive generation market, separation of the Transpower grid from the ECNZ, and introduction of competition at retail level. Box 7.1 lists the detailed recommendations.

Box 7.1
1989 Task Force Recommendations

Generation

- Generation entry barriers should be minimized and a regulatory rule against price discrimination by ECNZ be explored.
- Large-scale break up of the generation system is not favored but it is recommended that further study of the costs and benefits of spinning off one or two competitive generating companies be undertaken.
- Subject to satisfaction on competitive pressures in the generating sector, ECNZ should be privatized.

Transmission

- The ownership of transmission assets should be separated from the generator.
- Distributors and generators should form a club to own the transmission grid.
- The regulatory framework for transmission performance monitoring should provide recourse to and reliance on intervention provisions in the Commerce Act 1986.

Distribution

- Removal of franchise areas for the supply authority monopoly distribution and retailing of electricity, this to be combined with the removal of the obligation to supply.
- Tariffs to consumers should show transmission and distribution costs separately from energy costs.
- Supply authorities should be corporatized and subsequently privatized for listing on the share market.
- No regulation of retail energy prices, and regulation of distribution line charges should be "light handed".

Source: Report of the Electricity Task Force, 1989.

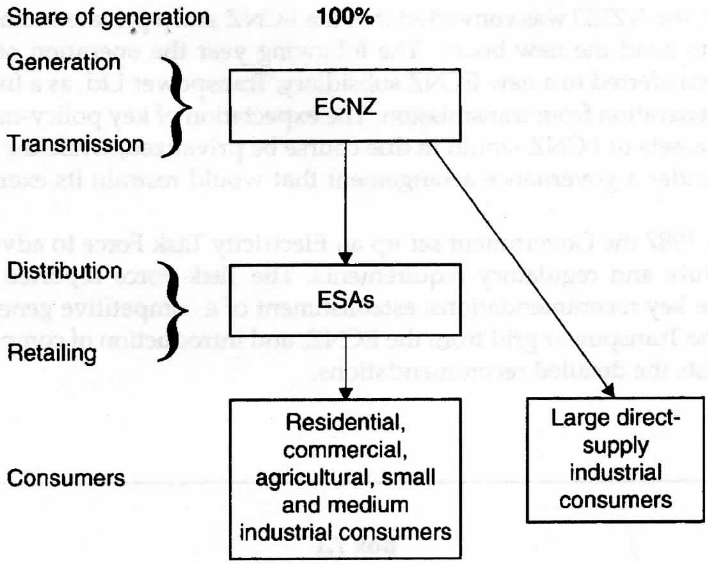

Fig. 7.3. Electricity industry structure 1990.

The last of these recommendations, namely no price regulation, and adoption of a light-handed approach to regulation in general, was wholeheartedly adopted by the Government. New Zealand's early decision not to set up an industry regulator, and to rely solely on general competition law (the Commerce Act 1986) to protect the competitive process and the interests of consumers, distinguished subsequent experience sharply from that in Australia where a specialist regulator was established. Until recently, Germany (see Chapter 8) was the only other OECD country to embark on electricity restructuring without a specialist regulator. Both New Zealand and Germany have now established such regulators.

7.3.2. *Initial structure*

Prior to restructuring, there were two tiers in the electricity sector: the NZED, a government department controlling all large generation and the high-tension transmission grid; and a large number of ESAs running low-voltage distribution networks bundled with retail energy sales and appliance sales and service. A limited number of large industrial customers took supply direct from the grid; all other final purchasers were customers of local franchise-monopoly ESAs. NZED delivered wholesale electricity (bundled generation and transmission) to distributors at a bundled price (the BST). The pre-reform structure is shown in Figure 7.3.

Distributors set prices to recover their costs, with price discrimination in favor of domestic consumers (low priced) relative to commercial customers (high priced) and industrial customers (in between). This price discrimination may have been Ramsey efficient,[9] but

[9] Residential electricity demand is probably more elastic than commercial, because of households' ability to switch to alternative fuels such as gas, coal, and wood.

was portrayed by reformers as being due solely to politically motivated cross-subsidies in favor of residential users (Jackson, 1990).[10]

Although it was a dominant monopoly, the NZED prior to the mid-1980s exercised its market power only in pursuit of a politically set target of covering costs and collecting a margin sufficient to fund new investment projects. Similarly, ESAs had secure monopoly franchises in their territories but their boards were accountable to consumers via regular elections, which had the effect of maintaining continual pressure on management to maintain high standards of supply and to seek only small profit margins.

The restructuring timetable over the two decades from 1984 is summarized in Table 7.2.

7.3.3. Generation and transmission restructuring

Change began with corporatization of the NZED in 1987 to form ECNZ. In 1994 generation was fully separated from transmission, leaving ECNZ with generation while the transmission grid company Transpower became an independent state-owned enterprise charged with operating the grid and scheduling the dispatch of generators. Thereafter, in a series of steps from 1996 to 1999, the larger ECNZ generation assets were split up among four successor companies: Contact Energy, Meridian Energy, Mighty River Power, and Genesis; while the smaller ECNZ stations (plus a number of other generation plants formerly owned by supply authorities) were privatized by sale to Trustpower, Todd Energy, and two smaller operations owned by Natural Gas Corporation (NGC) and Tuaropaki Power. Contact Energy was privatized by a share float in March 1999; the other three large successor companies remain state owned.[11]

By 2004 these were the eight generator class members of the New Zealand Wholesale Electricity Market.[12] The evolving market shares of the main generators, as measured by capacity, are shown in Table 7.3. Two generators, Contact and Meridian, between them now account for 57% of installed capacity, with the remaining 43% distributed among the other six players.

An important consequence of the break-up of the ECNZ generation portfolio was that some complementarities among different types of generation in the formerly integrated system were lost. Of the successor companies, Genesis was heavy on thermal plant and light on hydro; Meridian and Mighty River initially had only hydro and wind generation, with no thermal;[13] Trustpower's portfolio of small plants comprises entirely hydro and wind. The only operator to inherit a diversified generation portfolio was Contact Energy, the first firm to be split off from ECNZ and privatized. Contact's ownership of large North Island thermal (at New Plymouth, Otahuhu, and Stratford), large geothermal plant at Wairakei and Ohaaki,

[10] A feature of reform rhetoric in the early 1990s was the alleged need to eliminate "cross-subsidies" by lowering commercial tariffs and raising domestic ones. No evidence of the relative demand elasticities of these groups was ever publicly advanced to demonstrate that the prevailing price relativities were not Ramsey efficient. The elimination of retail price differentials in the 1990s was driven more by commercial-sector political lobbying than by economic analysis.

[11] There is no evidence to date that the state-owned companies have performed any differently from the private ones.

[12] http://www.nzelectricity.co.nz/C2bMarket.htm

[13] Mighty River subsequently took over a 125 MW gas cogeneration plant at Southdown, and was vested with ownership of the mothballed (never commissioned) Marsden B station, which it is now planning to convert to coal.

Table 7.2. Major milestones in the New Zealand reform process.

Event	Date	Comments
Pricing review	1984	Officials sought revenue gains from increasing electricity prices.
ECNZ established	1987	Corporatization of the state-owned generation and transmission system.
Electricity Task Force	1987	Task force set up to design restructuring program.
Partial grid separation	1988	Transpower set up as ECNZ subsidiary to be grid and system operator.
Task Force Report	1989	Recommendations: privatize generation and distribution, separate the grid as a club, end distribution franchises, adopt light-handed regulation.
Ministry of Energy abolished	1989	Removed Government's in-house specialist resource, hence lowered policy and analytical firepower available to Ministers.
ESA corporatization announced	1990	ESA boards converted to trustees, commercial directors appointed.
Transpower Establishment Board set up	1990	To implement Task Force recommendations re grid restructuring.
Transpower Establishment Board report	1991	Adopted the novel optimized deprival value methodology to value assets at separation from ECNZ; stuck with club ownership proposal.
Energy Companies Act	1992	Distribution companies (ESAs) to be corporatized.
Parliamentary Select Committee report on pricing	1992	Rejected ECNZ case for wholesale price increases; recommended adoption of progressive (increasing block) pricing of power. Echoed by private sector "Hydro New Zealand" proposal (Terry et al., 1992).
Winter supply crisis	1992	May–July drought caused blackouts; ECNZ water allocation criticized.
Committee of Inquiry	1992	Investigated the winter crisis, recommended greater security margins.
WEMS report	1992	Private-sector proposals for generation restructuring and pricing.
WEMDG set up by Government	1993	To advance WEMS agenda for competitive pricing and wholesale market.
Electricity Market Co	1993	New company established to manage and monitor a wholesale market.
Retail franchises removed	1993–1994	First small consumers, then large consumers open to retail competition.
Full grid separation	1994	Transpower becomes a State Owned Enterprise SOE; club proposal abandoned.
Disclosure regulations	1994	Information disclosure becomes mandatory for all lines businesses; accounting separation of retail and lines activities.
WEMDG report	1994	Recommended competitive pool and spot market, separate grid, long-term tradable wholesale contracts, restrictions on ECNZ market power.
Generation split up	1995	ECNZ to be split in two, small hydro to be privatized.
Contact Energy	1996	Separate SOE generator set up with 25% of ECNZ's generation assets.
MARIA established	1996	Industry arrangements to resolve competitive reconciliation issues at retail level.
Wholesale market	1996	Pool, spot price, wholesale market come into being.

Table 7.2. (Continued)

Event	Date	Comments
Auckland CBD event	1997	Distribution company's line into central Auckland city fails. Recurrent blackouts, emergency new line built by Transpower. Deferred maintenance probably a contributory factor to the breakdown.
Line/energy separation	1998	All ESAs forced to divest either their retail or their lines businesses.
ECNZ split announced	1998	ECNZ to be split into three state-owned generators at April 1999.
Contact Energy privatization announced	1998	Shares floated in March 1999; cornerstone 40% to Edison Mission.
ECNZ split carried through	1999	Now four major generators plus privatized small hydro.
MACQS agreement	1999	Industry self-governing arrangement for grid security.
Ministerial Inquiry	2000	Reported on regulatory issues; gave lines businesses a clean bill of health.
Governance Committee	2000	Electricity Governance Establishment Project to create a unified self-governing framework.
Electricity Industry Bill	2001	Made provision for direct regulation of lines businesses and Government imposition of governance arrangements if industry failed to self regulate.
Winter supply crisis	2001	July–September shortage due to low lake levels. Blackouts averted by voluntary savings achieved by publicity campaign.
On Energy bankruptcy	2001	Last independent retailer driven out, all retailers now vertically integrated with generators.
Hydro spill reporting	2002	Hydro generators must report any spillage to waste.
Market bids and offers disclosure	2002	Full detailed information to be published with a 4-week delay.
Light-handed regulation fails	2002	Commerce Commission retrospectively legitimizes lines businesses' asset revaluations.
Another dry-year looms	2003	March–June predictions of a dry winter, and Contact's withdrawal of some thermal capacity, led to major spot-price spike in April.
Targeted regulation	2003	Commerce Commission moves toward regulation of lines businesses.
Electricity Commission	2003	Industry regulator set up to organize governance, oversee supply security, build and contract for reserve thermal, regulate prices.
New regulatory framework for grid investment and pricing	2004	Electricity Commission to coordinate new investments in grid and generation.
New market arrangements	2003	Electricity Commission takes over the running of the sector under new rules and regulations.
Whirinaki opens	2004	New state-owned reserve generator to underpin security of supply.
Electricity Governance Rules	2004	New governance framework decreed by Electricity Commission after industry participants fail to reach agreement.
Core grid defined	2005	Commission identifies a subset of grid assets which must meet very high reliability standards to avoid "cascade failure".

Table 7.3. Generator shares of capacity, 1994–2004.

Firm	1994 Capacity (MW)	1994 Percent of total	1998 Capacity (MW)	1998 Percent of total	2004 Capacity (MW)	2004 Percent of total
ECNZ	7391	95.9	5361	66.2		
Contact			2046	25.2	2448	28.1
Genesis					1541	17.7
Mighty River					1266	14.5
Meridian					2539	29.1
Trustpower					452	5.2
Others	317	4.1	696	8.6	474	5.4
Total	7708	100.0	8103	100.0	8719	100

Sources: 1994 from *Electricity Enterprise Statistics 1994*, pp. 24–25. 1998 from ECNZ *Annual Report 1997*, p. 31; Contact Energy from *Prospectus* dated March 31, 1999, p. 21. 2004 from Ministry of Economic Development *Energy Data File* January 2005, pp. 116–119.

and two of the largest South Island dams on the Clutha River, has endowed it with greater ability than its competitors to schedule its generating plant strategically.[14]

The wholesale electricity spot market, set up in 1996 and run by the Marketplace Company (M-Co), is based on the interaction of supply and demand.[15] The final price is equal to the last offer price necessary to meet demand, in a single-price auction where all generators receive the same final price regardless of their bid prices. A constraint-adjusted spot price is then set for every half-hour at approximately 250 "nodes" on the national grid.[16] In theory, each nodal price is optimized to achieve the lowest overall cost to the country as a whole, given the offers into the pool by generators.[17]

There has been a sharp contrast between the adoption of complex and sophisticated pricing mechanisms on the supply side of the wholesale market and the almost complete absence of scope for economic incentives to operate on the demand side. The system operator treats demand as completely price inelastic, and there is no mechanism by which either electricity saving by consumers or small-scale distributed generation can participate in the wholesale market from the demand side. In the dry-year crises of 1992 and 2001 the Government resorted to mass publicity campaigns urging voluntary savings by consumers, but at no stage have economic rewards been offered for conservation effort.[18] The New Zealand electricity reforms have been notable for the absence of initiatives such as real-time retail pricing to reward conservation effort by consumers, and opportunities for small-scale distributed generators to enter the market.[19]

[14] A detailed history of Contact Energy in New Zealand, from an avowedly critical point of view, is at http://www.converge.org.nz/watchdog/08/06.htm

[15] NZEM Pricing, www.nzelectricity.co.nz

[16] NZEM Pricing, www.nzelectricity.co.nz

[17] NZEM Pricing, www.nzelectricity.co.nz

[18] An exception may be the Comalco aluminim smelter, whose contract with Meridian Energy is confidential but is rumored to include a provision for interruptibility.

[19] There is a strong contrast between New Zealand's effective foreclosure of small distributed generation and Tasmania's well-established policy of purchasing power from individual consumers who have installed photovoltaic equipment on their properties; see http://www.auroraenergy.com.au/askaurora/solarpower.html#Anchor-You-33869

The absence of initiatives toward providing consumers with time-of-use metering and pricing, or net-metering arrangements for consumers with small-scale generation of their own, has contributed to the inexorable growth of demand and stands in sharp contrast to the fine-tuned and complex system of pricing signals on the supply side. Perhaps most striking has been the adoption of a detailed nodal pricing system for the delivery of power off the grid.

7.3.4. Nodal pricing

A feature of the New Zealand reforms has been wholehearted adoption of the concept of detailed nodal pricing (Hogan, 1992, 1999; Ring et al., 1993a, b), with the result that there are no fewer than 250 separate nodal prices posted across a grid with only 480 entry and exit points. Much of this detail seems redundant to effective functioning of the market, and on balance has probably impacted negatively on market efficiency.[20]

Until recently there have been only two important bottlenecks in the New Zealand grid (see Fig. 7.2): the inter-island HVDC link, and the central North Island. (In the near future the latter constraint will shift northward to the transmission lines between Huntly and Auckland, once a planned new large thermal generator at Huntly is commissioned.[21]) The three key nodes in the system are Benmore (at the southern end of the HVDC link), Haywards (at the northern end of the HVDC link), and Otahuhu, in Auckland (north of the mid-North Island bottleneck).

Figure 7.4 shows that the spot prices at these three key nodes move quite closely together, although from time to time one or other of the two transmission constraints binds, causing regional prices to diverge. These divergences, however, are of second-order significance relative to the overall volatility of the wholesale spot price. Price divergences at the other 247 nodes are generally insignificant.

From time to time, the three principal nodal prices become separated due to grid constraints. During October 2000, for example, when the mid-North Island constraint was tight, the Otahuhu nodal price was roughly double the Haywards price, while Haywards and Benmore tracked closely together. Similarly, in January 2003, the Haywards price of 3.58 cents (c)/kWh became 5.03 c/kWh at Otahuhu, a difference of 41% from south to north of the North Island.[22]

An example of the HVDC constraint binding occurred in January 2002 when the Benmore price of 1.61 c/kWh was nearly doubled to 2.98 c/kWh at Haywards.[23] Again in December 2002, the Benmore price of 3.65 c/kWh became 4.94 c/kWh at Haywards, and 6.12 c/kWh at Otahuhu.[24]

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[20] It could be argued that the design and implementation of the detailed nodal pricing arrangement has been driven primarily by engineers and consultants for whom the issue has been both lucrative and technically interesting.

[21] Inspection of Figure 7.2 shows that major generation at or north of Huntly will be downstream of the central North Island constraint and will thereby relieve it. However, expanded transmission capacity will then be required between the new generator and the Auckland market. The siting of the new transmission line is at present embroiled in a difficult resource consent process.

[22] Figures for the examples of constraint pricing here are taken from http://www.nzelectricity.co.nz/electricity_prices/finals2003/August2003ReferencePrices.xls

[23] See NZEM, *Wholesale Electricity Prices Report* 19 February 2002, at http://www.electricity.co.nz/C2dPricesMonth/020219.htm

[24] The main grid constraints can also bind in the opposite direction, at times when water shortages in the South Island require electricity to move south rather than north. For example, in August 2001 (a crisis period in a dry year with South Island hydro operating well below capacity) the average Otahuhu spot price was 9.93 c/kWh, the Haywards price was 11.13 c/kWh, and the Benmore price was 12.73 c/kWh.

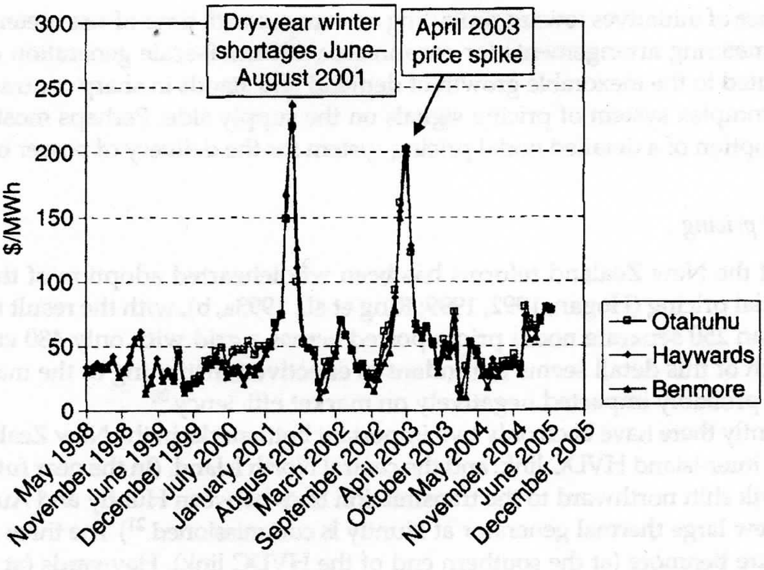

Fig. 7.4. Monthly average spot price at three main nodes, 1999–2004. *Source*: Data from http://www.stat.auckland.ac.nz/~geoff/elecprices/

These examples, however, are not typical of the day-to-day functioning of the system. In a month of normal operation, with no significant constraints apart from line losses, and with power moving north on the HVDC link, the three main nodal prices converge quite closely. In May 2005, for example, the Benmore spot price averaged 6.89 c/kWh, the Haywards spot price was 7.03 c/kWh, and the Otahuhu spot price was 7.09 c/kWh, an overall differential from south to north of only 3%.

7.3.5. *Distribution and retail restructuring*

The Energy Companies Act of 1992 forced all ESAs to corporatize their operations, moving to a commercial company structure with shareholders and profit objectives. In the case of municipally owned networks this was a straightforward process, since they had well-defined owners and already operated on a commercial footing. In the case of the rural Electric Power Boards (EPBs), however, no defined owners existed. The Boards had been set up from 1918 on as "creatures of statute" which installed and managed their network assets on behalf of the consumers who elected the boards. Under corporatization, EPBs were deemed to be owned by all consumers served at the moment of the changeover. A variety of creative schemes for issuing shares were implemented in the early 1990s.

Some Boards, transformed into joint-stock companies, issued shares to newly created elected trusts which held the shares on behalf of consumers in the same way as the EPBs had previous held their real assets. In other cases shares were gifted to individual consumers, many of whom took the opportunity to cash in by selling shares to private-sector interests, which quickly aggregated them into sizeable voting blocs. A period of consolidation by mergers and takeovers followed, as the more entrepreneurial of the new companies bought-up shares where possible, or took over control of trust-owned companies by direct acquisition where trust boards were willing. By early 2003, the four largest companies had captured 60%

Table 7.4. Consolidation of market shares in distribution networks: GWh carried.

	1995	1998	2001	2004
Power New Zealand/United Networks	2569	3384	7120	**
Vector Ltd	4053	4432	4990	10,257
Powerco	347	1019	2083	4074
Orion Ltd	2416	2582	2822	3080
Total, big four	9385	11,418	17,015	17,412
Other companies	13,700	14,422	10,711	12,488*
Total GWh	*23,085*	*25,840*	*27,726*	*29,900**
Share of big four (%)	40.7	44.2	61.4	58.2

*Estimate.
**Taken over 2003 by Vector and Powerco, who divided up the network assets.
Source: MED disclosure statistics, at http://www.med.govt.nz/ers/inf_disc/disclosure-statistics/, plus company disclosures for 2004 financial year.

of the distribution lines business, up from 40% 10 years earlier. In 2003 a further merger reduced the number of industry leaders to three (see Table 7.4).[25]

The Electricity Industry Reform Act of 1998 forced ownership separation of electricity retailing from the operation of distribution networks. Most of the existing distributors opted to retain their natural-monopoly lines businesses and divest their retail arms. The retail businesses, with their customer bases, were quickly snapped-up in 1999–2000 by the five main generators, which thereby achieved vertical integration of their generation plants with retail outlets.[26] The supply of wholesale power to these retail affiliates then became an intra-firm transfer, largely removing any need for the large generators to enter into open-market long-term contracts or sell more than a marginal part of their generation through the spot market.

In the very light-handed New Zealand regulatory environment of the 1990s, vertically integrated generator retailers had a strong competitive advantage over stand-alone retail

[25] It appeared to some observers in the 1990s that the new corporate culture of the major network companies, with its focus on mergers and acquisitions, might shift management priorities from ensuring reliability of supply to financial issues such as the market valuation of the enterprises. Claims of this sort were heard especially in relation to the failure of all the high-tension cables supplying the downtown Auckland area in 1998, due to a combination of improper installation and poor maintenance practice. An inquiry into the failure concluded that "Mercury (the relevant network company, since renamed Vector Ltd) does not have an adequate maintenance policy for 110 kV gas and oil filled cables. It did not comply with manufacturers' recommendations in regard to the routine testing of gas pressure and oil pressure alarms and accuracy of their initiating devices, and electrical checking of the integrity of the outer coverings of the cables." See Integral Energy Australia, *Inquiry into the Auckland Power Supply Failure* http://www.med.govt.nz/inquiry/publicsummary.html#P117_7323 conclusion xvii.) These failings, however, predated the corporatization process and at most it would seem that the new culture failed to remedy them.

[26] Non-major retailers survived only in a few isolated rural areas such as the King Country in the central North Island. (King Country Energy's independent-retailer status is buttressed by ownership of (and vertical integration with) local small hydro amounting to 50% of its retail load. It also has a 50% share in the large Mangahao hydro station in the Manawatu. See http://www.kcenergy.co.nz/generation.html

businesses because of their ability to hold physical hedges[27] within each company, whereas independent retailers had either to secure hedge contracts from generators on an extremely thin market, or face exposure to the spot price. Even faced with a dry-year crisis in 2001, the New Zealand Government took no steps to compel generators to offer hedge contracts on the open market. With no regulatory or statutory protection against the exercise of market power by the vertically integrated generator-retailers, almost all independent retailers were deprived of either profitable arbitrage opportunities or access to profitable long-term contracts, and quickly exited the market.

Only a single large independent retailer remained by the end of 2000. In 1996 the Canadian company TransAlta had acquired a substantial share of the distribution and retail market, but in 1999 the company was unable to acquire a large enough generation portfolio to match its retail sales volume.[28] Faced with large upstream exposure to the hedge and spot markets, TransAlta quickly sold its New Zealand business for $830 million[29] to New Zealand's dominant natural-gas pipeline and retail company, NGC. Possessing only 399 MW of generation capacity, and having failed to secure forward hedge contracts to cover the winter of 2001, NGC's retail affiliate On Energy found itself in June 2001 in a critically dry winter with almost full exposure to the spot market for its supply of electricity.[30] The company could not raise its retail price to cover the high wholesale prices, because its vertically integrated competitors kept their retail prices unchanged throughout the crisis. As NGC's subsequent annual report ruefully noted, recording losses of $304 million from this classic cost–price squeeze:[31]

> "Wholesale prices increased to up to four times their normal levels, placing a pronounced strain on NGC's cash flows, profitability and financing arrangements, and raising serious questions about the operation of the market itself. NGC decided to withdraw from electricity retailing and completed its exit on August 1, 2001 following the sale of its retail electricity customers to two Government-owned energy companies. NGC's withdrawal from that business closed off future retail exposure to the volatile wholesale electricity market and crystallized the resulting losses."

Of the retail customer base of 405,000 which NGC had acquired from TransAlta NZ Ltd the previous year, representing 23% of all electricity consumers, 115,000 were sold to Meridian Energy and 290,000 to Genesis Power Ltd. Since then the vertically integrated five generator oligopoly of retailing has been unchallenged.

The elimination of non-generator parties from the retail market spelt a halt to the process of competition for retail customers, which had briefly flourished in the 2 years following the 1998 separation of lines and energy retail activities. Figure 7.5 shows that the new-entrant

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[27] Retailers can hedge their costs of future wholesale supply either by long-term contracts with generators, or by directly owning physical generating plant. The practice of physical hedging in New Zealand has foreclosed the emergence of a liquid hedge market; this in turn has constituted a major barrier to new entry by independent retailers.

[28] TransAlta in 2000 held more than 20% of New Zealand's electricity consumers but less then 5% of generating capacity.

[29] *NGC Becomes Majority Owner of TransAlta*, media release dated 31 March 2000, http://www.ngc.co.nz/article/articleprint/166/-1/21/. The price represented a $300 million tax-free capital gain for TransAlta.

[30] The wholesale spot-price spike of June–August 2001 is dramatically apparent in Figure 7.3 above.

[31] Natural Gas Corporation, *Annual Report 2001*, p. 5.

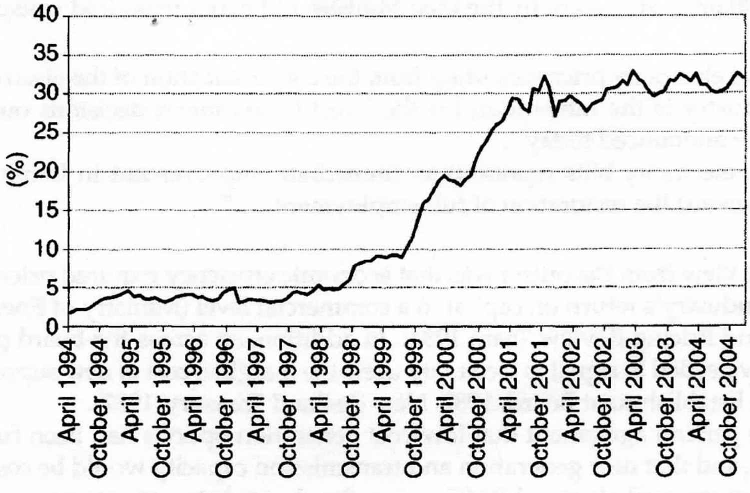

Fig. 7.5. Share of non-incumbent retailers in former franchise territories. *Source*: Stratagen.

share of retail sales in former franchise territories, following removal of franchises in 1993–1994, remained very low until the Electricity Industry Reform Act 1998 separated retail from distribution. Retail competition took off in 1999–2000, but froze again at around 30% as soon as On Energy had been driven out in mid-2001. Three years later, Murray and Stevenson (2004, p. 18) reported to the Electricity Commission that "customer switching figures seem to have declined and stabilized over a period when prices have been rising" and that "price trends suggest electricity prices are probably higher on average than they would be in a workably competitive market".

The 1989 Task Force vision of competitive retail markets served by a liquid market for forward hedge contracts, thus, ran aground on the reality of generators' market power. The anti-competitive effect of vertical integration of generation with retail had not been foreseen at the time of the 1998 separation of retail from distribution networks. Consequently no consideration was given to requiring generators to transact with their retail affiliates via an arms-length contestable market for hedge contracts, and although proposals for such compulsory hedging were discussed during the 2001 crisis, Government took no steps to remedy the extreme thinness of the forward contracts market.[32]

7.4. Pricing, Profitability, and "Light-Handed Regulation"

7.4.1. "Efficient" pricing

A dilemma over the meaning of "efficient prices" dogged the electricity reform process from the outset, and remains an unresolved issue two decades later. One interpretation in the mid-late 1980s was that since the electricity system was breaking even in cash terms at its existing prices, efficiency-enhancing reforms ought to bring down the prices paid by final consumers, and certainly ought not to lead to rising prices.

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[32] The issue now rests with the recently established regulator, the Electricity Commission.

A May 1990 press statement by the then Minister of Energy reassured consumers:[33]

> "Lower real electricity prices resulting from the corporatization of the electricity distribution industry is the motivation for the latest Government decisions on electricity which were announced today ...
> Savings in electricity bills represent an immediate improvement in living standards and help toward the restoration of full employment ...."

An opposing view from the outset was that economic efficiency required prices to increase, to raise the industry's return on capital to a commercial level (Ministry of Energy Financial Objectives and Pricing Review Team 1984). In addition, an across-the-board price increase was allegedly needed to signal to electricity users the marginal cost of new supply (Electricity Corporation Establishment Board, 1987; New Zealand Treasury, 1987).

There was general agreement that low-cost generation options had been fully exploited by the 1980s, and that new generation and transmission capacity would be costly to install. Faced with an upward-sloping LRMC curve, the choice between average- and marginal-cost pricing presented a political dilemma. If the restructured electricity industry were to be allowed to price at LRMC, the inevitable result would be higher prices to consumers and very large operating surpluses on the existing hydro generation plant, far in excess of the surpluses required to yield a competitive return on, and of, the book value of already-existing capital (Bertram, 1988). If a lower average price were set to recover the full cost of supply, including a commercial rate of return on the book value of existing assets, then the resulting price signal would render new investments unattractive while encouraging excessive growth of demand.

Two solutions to this dilemma were on offer. The consumer-oriented position was either to stick with an average-cost price and accept any consequent inefficiencies;[34] or to adopt a non-linear tariff structure to achieve the same outcome of restricting existing generators' total revenue, while providing efficient price signals at the margin. The latter solution was supported by a parliamentary select committee (New Zealand House of Representatives, 1992) and in a report commissioned by a group of major users (Terry et al., 1992).[35]

The other approach to wholesale pricing, championed by the Treasury and ECNZ, was to charge consumers the full LRMC price, and to legitimize the resulting cash surpluses that would accrue to generators, the grid operator, and the distribution networks, by revaluing their existing assets up to a level at which the rate of return on capital would appear to be no more than "normal". In 1987 Treasury had estimated that the BST should be raised from less than 6 c/kWh to somewhere in the range 8–11 c/kWh (New Zealand Treasury, 1987, p. 4).

The Labor Government, which initiated the reforms, was replaced at the 1990 general election by a National Party regime in which the Treasury view prevailed. In terms of

[33] Hon David Butcher, press statement dated May 25, 1990.

[34] Advocates of this approach in the mid-1980s included the New Zealand Business Round Table (1985), Ernst and Whinney (1985), Frater et al. (1985) Jarden and Company (1985), McDonald (1985), Scott and Co (1985), and University of Waikato Interfirm Comparison Unit (1985).

[35] Another pricing arrangement with the same basic thrust would have been to rebate to consumers any excess profits resulting from application of a uniform LRMC price, possibly by means of a lump-sum reduction in fixed lines charges funded from generation surpluses, along the lines later adopted in the UK by Scottish Hydro.

electricity-sector reform, this meant support for "full-cost uniform pricing" of electricity, which translated in practice into higher overall prices for consumers, with any efficiency gains that might result from restructuring being captured as additional profit.

Treasury argued that electricity prices needed to rise rather than fall, to signal LRMC; that no regulatory barrier should be placed in the way of electricity suppliers pushing their prices up to the "limit prices" at which, in theory, the threat of entry by new competitors would cap prices; and that gains from increased prices and/or reduced costs, provided they fell below the contestability threshold, could legitimately be taken as profits and built into the asset valuations shown in the companies' regulatory accounts. This tolerance for wealth transfers from consumers to suppliers[36] meant that New Zealand's regime of so-called "light-handed regulation" lacked any bright-line test for abuse of market power until all assets had been revalued up to the replacement-cost ceiling, and companies had adjusted their margins to match the higher ratebase. It also reveals the extent to which New Zealand policy-makers adopted without qualification some recent developments in economic and accounting theory, which other OECD governments have treated with more circumspection.

7.4.2. *Economic and accounting theory and the New Zealand reforms*

Economic policy-making in New Zealand in the late 1980s and early 1990s was heavily influenced by three overseas developments in the economics and accountancy literature. These were:

- The proposition, familiar from early UK debates over electricity restructuring, that electricity generation and retailing were potentially competitive activities and that in relation to those two levels of the electricity market, therefore, policy intervention could be limited to promoting competitive conditions, not to controlling prices.
- The theory of contestable markets set out in Baumol et al. (1982). Contestability theory was interpreted to mean that in a process of "competition for the market", a natural monopolist would be unable to price above the limit at which a new entrant would be attracted. This, New Zealand officials reasoned, meant that if an incumbent monopolist's assets were revalued up to replacement cost, no more than a competitive rate of return on that valuation would be achievable unless management could cut costs by improving efficiency. Hence, although electricity lines networks were natural monopolies, officials decided no regulatory restraint on price would be necessary, as market disciplines would do the job unaided; all that would be required would be transparent information disclosure.
- The newly fashionable method of accrual (current-cost) accounting, which prescribed that fixed assets should be continually revalued to market value, and that profit and loss statements ought to reflect changes in shareholder wealth accruing as a result of each year's trading activity. In the hands of the New Zealand accounting profession, this methodology was incorporated into "generally accepted accounting practice" (GAAP) in a partial manner that opened the way to manipulation of asset valuations. To summarize a complex story, New Zealand's Accounting Standard SSAP28 (later FRS3) prescribed that natural-monopoly entities whose assets do not (by definition) have a competitive

[36] The two Government departments most closely associated with electricity regulation during the 1990s, Treasury and the Ministry of Commerce, adopted and promoted the so-called "total surplus standard" for regulation. This standard treats all pure transfers as welfare-neutral and hence of no concern to the regulatory authorities. See Bertram (2004).

arms-length market value, should value their fixed assets at optimized depreciated replacement cost (ODRC), which was claimed to approximate the capital cost of setting up from scratch a new supplier providing the same service, to the same standard, as the incumbent (Cooper, 1995). This valuation could then be used as the ratebase for setting and justifying prices. In the view of the officials overseeing the light-handed regulatory regime during the 1990s, no concern over excess profits could arise so long as no more than a competitive rate of return on the ODRC-valued assets was revealed in the regulatory accounts prepared for disclosure purposes by all transmission and distribution network owners.

If assets were to be continually revalued to the hypothetical contestability limit, consistency required that the profit-and-loss account should record as income all wealth changes accruing to the shareholders, whether by virtue of current cash flows or of asset revaluations. New Zealand's GAAP, however, did not (and still does not) require this to be done for upward revaluations. Gains and losses on the actual sale of particular assets are recorded in the profit-and-loss account, as are all *negative* revaluations (asset write-downs).

The crucial omission is the treatment of upward asset revaluations (effectively, negative depreciation). Rather than being recorded as revenue in the profit-and-loss account, these are recorded separately in a "revaluation reserve", usually hidden deep in the notes to the financial statements. Under this procedure, the accrual to a company's books of hundreds of millions of dollars of revaluations of fixed assets need never be recognized as income, and so can be excluded from recorded profits for both taxation and regulatory purposes,[37] while the revalued assets can be used as the ratebase for price setting and justification.

7.4.3. *Generation and the wholesale spot price*

Figure 7.6 shows the generation supply curve for May 2004, constructed by stacking the various generation plants in merit order of variable operating cost. The large hydro plants,

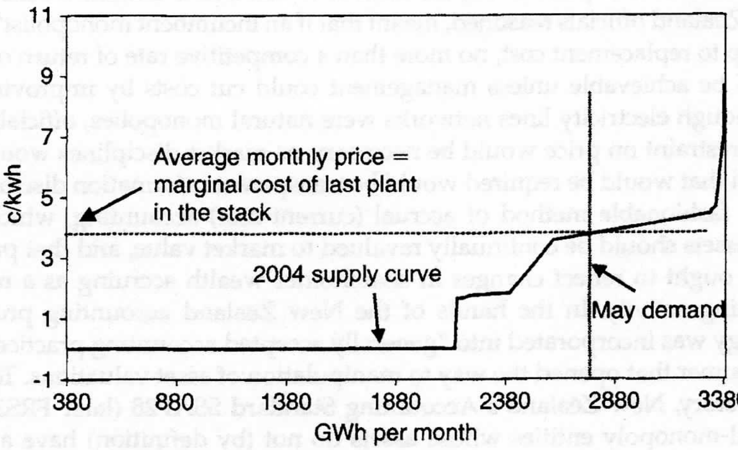

Fig. 7.6. Generation supply curve 2004.

[37] This practice is acceptable to the tax authorities because New Zealand does not have a capital gains tax.

whose operating cost is close to zero, crowd the higher-operating-cost thermal and geothermal units out to the marginal one-third of the market. The upward-sloping curve at the right of the diagram shows these various non-renewable units stacked in merit order. The market-clearing spot price, which provides, over the long run, the anchor for long-term wholesale supply contracts, is found at the point on the supply curve at which aggregate demand intersects the supply curve. The May 2004 demand, it can be seen, lay only about 400 GWh (14% of monthly demand) inside the point at which the supply curve turns sharply upwards. In this situation, radical price spikes can be anticipated if either demand rises, or supply falls, by this amount. The months following May are winter in New Zealand, when demand is higher and the system's ability to meet demand without price shocks rests heavily on the volume of very low-operating-cost hydro generation made available by the owners of hydro plant.

By withholding even a small part of the available water from use for generation at times of strong demand, the owners of large hydro plants can potentially pull the bidstack to the left, thereby (deliberately or inadvertently) driving up the spot price and raising their operating surplus – an opportunity for the exercise of market power mitigated in the New Zealand case only by the existence of a duopoly, rather than a monopoly, of major hydro generators with the necessary market leverage. The very steep profile of the supply curve beyond about 3000 GWh per month confers substantial market power on any hydro generator (or cartel of generators) with the ability to withhold capacity and thereby shift the bidstack to the left.

To achieve such withholding, a hydro generator must either have unutilized water storage capacity which can be allowed to fill while generation is curtailed; or else must be able to dispose of unwanted water by hydro spill.

New Zealand policy-makers became aware only in 2001 (5 years after the break-up of the ECNZ generation portfolio) of the possibility that hydro generators might game the spot price by spilling water to waste. The Government's ex-post review of the 2001 dry-winter supply crisis brought to light the fact that in the summer of that year Meridian Energy had been spilling water from Lake Tekapo. Whether this was strategic behavior to drive up price (as one distributor alleged), or responsible management to avoid flood risk (as Meridian claimed),[38] the issue was placed on the agenda for regulation, and new rules subsequently came into force requiring generators to report each month on the details of any spill.[39] Since 2001 there has been very little hydro spill recorded.

Use of empty storage capacity to withhold water, however, is not so subject to Government control. An example of the strategic importance of commercial generators' restriction of hydro generation in order to build up (or protect) the level of storage lakes was the price spike of April 2003, visible in Figure 7.3.

Rainfall in the early months of 2003 was below normal, and lake storage fell below the levels required to ensure ability to meet the forthcoming winter demand. The two large hydro generators in the South Island (Meridian and Contact) both cut back water use, citing the need to conserve water and maintain storage levels ahead of the coming winter. At the same time, Contact took its 357 MW gas-fired Stratford station offline in mid-April for

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[38] See *Electricity Post-Winter* Review, 2001, Section 2.2, http://www.winterreview.govt.nz/submissions/summary/summary-03.html#P186_28826

[39] Hydro spill reporting is now to the recently established Electricity Commission; see http://www.electricitycommission.govt.nz/opdev/secsupply/sos/overview/hydrospill1/

maintenance.[40] Both actions shifted the bidstack significantly to the left. As lake storage levels dropped to 60% of normal for the time of year, the spot price was driven up sharply to an average for the month of 20 c/kWh, and Government solicited voluntary demand restraint by electricity users in order to avoid blackouts. Rainfall subsequently increased during May and June and the supply situation eased, bringing the spot price back down to 6 c/kWh by June.

The extreme volatility of the spot market in the April 2003 event was attributable not only to the high shadow price implicitly assigned to water by Contact and Meridian Energy. It was worsened significantly by the fact that the New Zealand bidstack in 2003 had far less reserve thermal plant, and hence a much steeper right-hand end, than had been the case at the beginning of the reforms. In the dry year 1992 the ECNZ portfolio had included four high-operating-cost thermal plants, which were brought online to compensate for the water shortage. Because these plants' capital costs were sunk, the only economic cost of bringing them online was the operating cost, primarily fuel. By their mere existence, these plants exercised a moderating influence over the spot market by placing a ceiling on the spot price over a range of several hundred MW of supply capacity.

Table 7.5 shows the thermal high-cost reserve capacity that had been available in 1992 (when operation of the Marsden A oil-fired station during the dry-winter crisis reduced the scale of blackouts in the Auckland region), and compares this with the corresponding reserve capacity available in early 2003 before the April price spike. The difference is striking. Under commercial incentives and supposedly competitive conditions, the former owners of thermal reserve plant had decommissioned and/or demolished a total of 620 MW of reserve capacity.[41] Over the same period, roughly 1000 MW of new thermal plant was commissioned, but none of this qualified as reserve capacity to cover dry years; the Southdown and Otahuhu B stations simply helped supply to keep up with growing demand, while the cogeneration stations perform no role in relation to dry-year firming, since their operation is tied to the steam requirements of the host facilities.

Having failed to persuade any of the commercial generators to invest in new reserve plant, the Government opted in 2004 to spend $160 million on construction of a new 155 MW diesel-fired thermal station at Whirinaki, where Contact Energy had demolished an almost identical plant a couple of years previously. The station, although owned by the Crown, is maintained and operated by Contact Energy under contract, and is not to be dispatched at a price of less than 20 c/kWh[42] (roughly the monthly average price during the April 2003 price spike, see Fig. 7.3).

7.4.4. *Grid pricing*

The high-voltage transmission grid was transferred in 1994 to a new State-Owned Enterprise, Transpower Ltd, following several years of debate over asset valuation and pricing.

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[40] NZEM, *Declining Storage Levels Fuel Rising Electricity Prices* 7 May 2003, http://www.nzelectricity.co.nz/C2dPricesMonth/030508.htm

[41] Prior to 1992, the 133 MW Meremere coal-fired station in the Waikato had already been decommissioned by ECNZ in 1990. Marsden A (114 MW) was closed in mid-1992 and demolished in 1997. Stratford (200 MW) closed in late 1999. Otahuhu A (90 MW) and Whirinaki (216 MW) were decommissioned in 2002.

[42] Electricity Commission, *Explanatory Paper to the Initial Security of Supply Policy*, June 2005, http://www.electricitycommission.govt.nz/pdfs/opdev/secsupply/policy/Initial-SOS-Policy-Explan-Paper.pdf, Part VII p. 21.

Table 7.5. Thermal generating capacity, March 1992 and March 2003 compared.

Station	1992 capacity (MW)	Operating cost, c/kWh, 1991	2003 capacity (MW)
New Plymouth	580	3.13	400
Huntly	1000	2.92	1000
Stratford TCC	198	3.97	355
Otahuhu B	0	n.a.	380
Southdown	0	n.a.	118
Big thermal total	*1778*		*2253*
Stratford	200	3.97	0
Otahuhu A	90	6.27	0
Marsden A	114	7.43	0
Whirinaki	216	18.5	0
Total high-cost dry-year reserve thermal	*620*		*0*
Te Awamutu cogen	0	n.a.	52
Kinleith	0	n.a.	40
Te Rapa	0	n.a.	44
Edgecumbe	0	n.a.	25
Kapuni	0	n.a.	355
Whareroa	0	n.a.	65
Cogen total	*0*		*581*
Total thermal	***2398***		***2834***

Sources: 1992 capacity data from *Annual Statistics in Relation to Electric Power Operation in New Zealand for the Year Ended March 31, 1992*, pp. 57–59. 2003 capacities from *Energy Data File* July 2003, pp. 108–109. Operating-cost estimates from Terry et al. (1992), p. 128.

Following the 1987 transfer of the NZED generation and grid assets to ECNZ at a negotiated vesting value of \$6.3 billion, ECNZ undertook the task of allocating this lump-sum valuation across its generation and grid assets. The transmission system was assigned a value of \$2.1 billion, and generation and other fixed assets \$4.2 billion.[43]

In July 1990 the Transpower Establishment Board was set up to oversee the separation of the grid from ECNZ. A central issue confronted by the Board was the valuation that should be assigned to the grid assets when they were fully vested in a new independent company. ECNZ management and Treasury were focused on achieving privatization of the generation assets at a high price, and this could best be achieved by off-loading as much as possible of the Corporation's debt into the books of its grid subsidiary, allowing the generation assets to be sold relatively unencumbered by debt. In addition, a range of operating expenses formerly attributed to generation were transferred to Transpower prior to separation (Terry et al., 1992, p. 87), raising the reported profitability of ECNZ's generation business in readiness for sale.

A higher valuation of the grid assets was then required to bring Transpower's debt–equity ratio down to a commercially sustainable level. The TPEB achieved this objective by having the grid assets revalued to "optimized deprival value" (ODV), a variant of depreciated replacement cost. This resulted in a valuation of \$2.55 billion (Ernst et al., 1991). The higher asset value and increased operating costs were used to justify a real increase of 21% between 1989 and 1991 in the grid transmission charge per kWh conveyed.

[43] ECNZ *Annual Report 1989*, p. 47.

Over the decade following its establishment as an state-owned enterprise, Transpower paid down its debt and wrote-down its ODV asset valuation in recognition that the long-run sustainability of the grid itself depended upon transmission prices low enough to compete with distributed generation connected directly to distribution networks, for which transmission service would not be required. To protect the grid's pre-eminent position in the short term, Transpower used its market power to impose contract conditions on distributors which obliged them to collect transmission charges on all power delivered, whether it was taken from the grid or generated locally by suppliers connected only to the local network. These contract conditions, by imposing high fixed connection charges regardless of load changes, also eliminated the prospect that retailers might be able to profit from demand-side conservation initiatives. The resulting barrier against entry by small-scale distributed local generation, and the equally suffocating effect on local demand-side conservation initiatives, effectively foreclosed development of both for a decade.

7.4.5. Distribution networks

Legislation to force through the corporatization of ESAs was passed in 1992, and the process was largely completed by April 1994. As the new companies were set up, the issues of asset valuation and price setting had again to be addressed. Following the Transpower precedent, the Minister of Energy and the Treasury planned to revalue all assets up to ODV prior to vesting, enabling the new distribution companies to start off with a new, higher ratebase against which their profitability could be monitored under a light-handed regulatory regime of information disclosure.

It was obvious to all industry participants, including major users, that the historic-cost asset valuations in the books of the pre-corporatization ESAs were far below depreciated replacement cost. Roughly speaking, at 1994 the network assets of all networks combined had a book value of $2 billion, but a replacement-cost valuation would come to double that amount.[44] If the new companies were gifted a $2 billion asset revaluation at the time the assets were vested, two politically significant groups stood to lose. One group was electricity users, who effectively would have to pay for the increased profits required if the distribution companies were to meet commercial rate-of-return targets on their revalued ratebases. The other group were private investors eager to make capital gains by acquiring distribution assets cheaply and then undertaking the revaluations themselves.

Early in the restructuring process it became apparent that switching to a replacement-cost ratebase for pricing supply to customers in low-density areas would sharply increase electricity prices in low-density rural areas with a high ratio of line length per customer. A confidential survey undertaken by officials in 1989–1990 found that "full-cost pricing" would require price increases of up to 300% for rural electricity users.[45] Faced with the prospect that the political fallout would halt the reform process at the outset, Treasury fell back on a modified form of replacement-cost valuation called ODV, which included the proviso that whenever the economic value of an asset (the discounted present value of expected revenues[46]) was below full ODRC, the asset would be written down and the users of the asset

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[44] Cabinet documents recently released under the Official Information Act reveal that these orders of magnitude were known to ministers and officials in 1991, 3 years before vesting took place.

[45] Cabinet committee document SAS (90) 31, March 13, 1990, p. 10.

[46] The circularity between asset values and revenues was well understood. The ODV technique enabled the revenues extracted from specific groups of consumers to be selectively capped, with the ratebase valuation of the assets serving that group written down accordingly, leaving an ostensibly competitive market return on the assets for disclosure purposes.

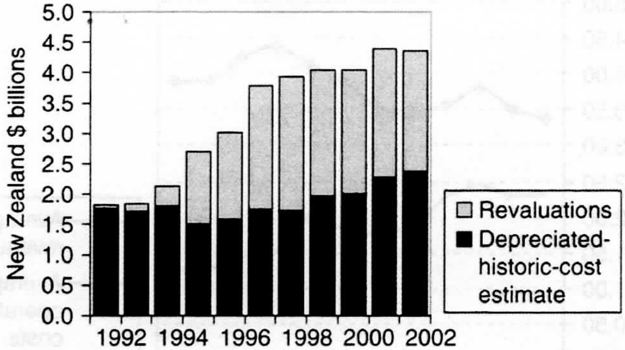

Fig. 7.7. Asset book values of electricity distribution networks, 1992–2002. *Source*: Bertram and Terry (2000, p. 7).

thereby protected from rate shock. This ingenious solution became embedded thereafter in the valuation procedures for both grid and distribution networks.

In the event the new National Government elected in late opted pragmatically to continue the time-honored practice of using revenues from densely populated parts of each ESA's territory to cross-subsidize the prices charged in low-density areas – a procedure which had been generally accepted by consumers since the 1920s.[47]

Neither the ODV concept nor the decision to retain urban–rural cross-subsidies removed the looming prospect of a general price shock if network asset valuations were doubled across the board. In October 1991, Ministry of Commerce officials estimated that the ODV valuations would be 2.5 times the existing book values.[48] Modeling carried out for the Government in April 1992 by a local accountancy practice suggested that a rate shock of 25% would be required to meet the required return on a revalued ratebase.[49]

Treasury at this stage proposed that the assets should be vested at book value but that the new companies be allowed to revalue to ODV without facing any regulatory restraint. It would then be the responsibility of the new corporate boards to decide whether to squeeze their customers or accept below commercial rates of return.[50] Cabinet agreed,[51] and the Establishment Boards of the new companies were instructed to adopt existing book values for their opening balance sheets. Figure 7.7 shows the subsequent process of increasing the regulatory ratebase by writing-up asset values to replacement cost.

Figure 7.8 shows the evolution of prices and average costs of lines networks over that period. Free from regulatory restraint, the sector raised its aggregate Lerner Index from 0.36 at vesting to 0.68 by 2001.

The loophole in the regulatory system was well known to, and understood by, industry insiders. It was equally obvious to analysts familiar with current-cost accounting theory. The procedure of vesting the assets at historic cost, while signaling to the new owners that ODV valuation would be the regulatory benchmark, transferred responsibility for

[47] Corporatized ESAs are compelled, under the reform legislation, to maintain supply to all rural customers until 2013. Thereafter they will be allowed to disconnect unprofitable customers.

[48] Ernst and Young, letter to Michael Lear, Ministry of Commerce, May 14, 1992, p. 1.

[49] Ibid., p. 3 of appendix. Ernst and Young pointed out in this letter that recognizing asset revaluations as income would reduce the required rate shock to between 5% and 9%, but the point was not taken by officials.

[50] Officials' briefing document for Minister of Energy, May 8, 1992.

[51] Cabinet State Sector Committee document STA (92) 96.

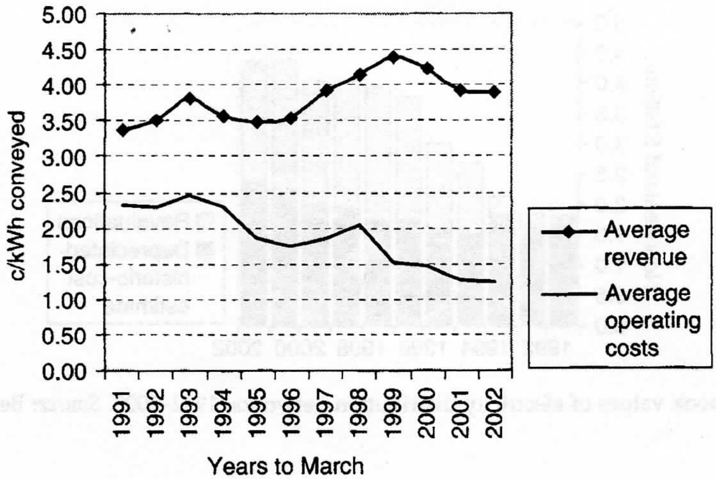

Fig. 7.8. Price–cost margin of electricity distribution networks, 1991–2002. *Source*: Bertram and Twaddle (2005, p. 295), Figure 1(f).

subsequent increases in margins and prices from the Government to the distributors but left consumers unprotected.

In a current-cost accounting framework, profitability should be measured with revaluations (changes in shareholder wealth) recorded in the profit-and-loss accounts. New Zealand's GAAP did not require this to be done.[52] Lines companies were therefore able to inflate the denominator and reduce the numerator in their profit calculations, as justification for an annual wealth transfer from consumers to distribution network owners of $200 million annually (0.2% of GDP) from the late 1990s on (Bertram and Twaddle, 2005).

Perhaps ironically, the information disclosure regulations for electricity lines networks, promulgated in 1994, included a requirement for companies to disclose an "accounting rate of profit" which included the wealth effects of ratebase revaluations,[53] and this requirement was complied with, resulting in the disclosure of profit rates often of 30–40%, and in one case as high as 90%,[54] with no reaction from Government.[55]

[52] This issue had been thoroughly discussed prior to the UK privatizations, and the regulatory accounting implications worked out, in the "Byatt Report", *Accounting for Economic Costs and Changing Prices: A Report to HM Treasury by an Advisory Group*, London: HMSO, 1986, Volume 1.

[53] Ernst and Young, as advisers to the Ministry of Commerce, set out the correct accounting procedures in a letter of May 14, 1992, and explained the correct interpretation of the Accounting Rate of Profit (later renamed the Return on Investment) in Ernst and Young (1994).

[54] Far from recognizing the implications of these numbers, a 2000 Ministerial Inquiry rejected the calculation methodology itself and found no grounds for regulatory concern (Caygill et al., 2000, Table 7.3, p. 14, and p. 15 paragraph 75).

[55] The largest lines company, United Networks, disclosed a return on equity of 235% for 2000, 347% for 2001 and 125% for 2002, without attracting attention from Parliament, media, or officials. See *New Zealand Gazette* 2000, No. 111 p. 2807 (http://www.dia.govt.nz/Pubforms.NSF/URL/UnitedNetwork111Aug00.pdf/$file/UnitedNetwork111Aug00.pdf); 2001, No. 104 p. 2665. (http://www.dia.govt.nz/Pubforms.nsf/URL/Unitednetworks104Aug01.pdf/$file/Unitednetworks104Aug01.pdf); and 2002, No. 122 p. 3272. (http://www.dia.govt.nz/Pubforms.nsf/URL/UnitedNetwork122.pdf/$file/UnitedNetwork122.pdf). In fairness it should be noted that the taking of monopoly profits is not illegal under New Zealand competition law. Consumers have no legal redress against high prices, and the Electricity Complaints Commission set up in 2001 was barred from hearing complaints about pricing. See http://www.electricitycomplaints.co.nz/faqs.htm

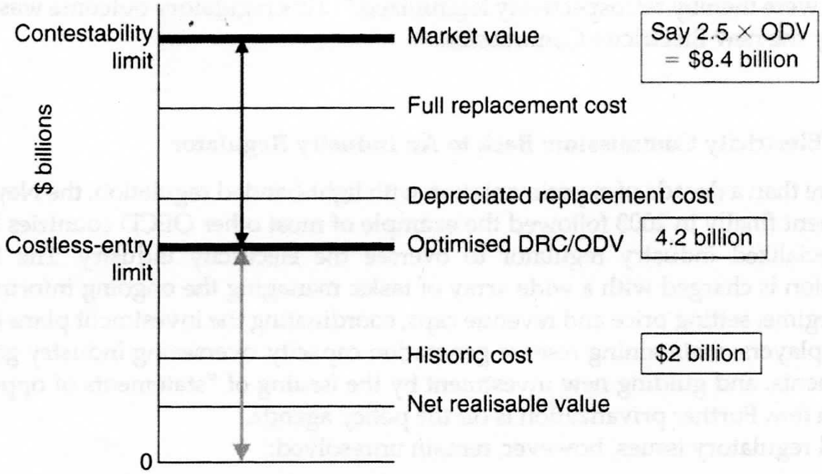

Fig. 7.9. Range of possible ratebase valuations for the distribution networks.

Figure 7.9 shows schematically the range of feasible asset valuations, any of which could have been arbitrarily chosen for ratebase purposes. The theoretical limit valuation under conditions of perfect contestability (zero costs of entry and exit) is represented by the ODV of $4.2 billion – more than double the pre-corporatization historic cost. Adding in the observed effects of barriers to entry (in particular, very high fixed costs of entry and exit) raises this further by a factor of 2.5 (based on the actual purchase price of distribution networks taken over as going concerns).

In short, the New Zealand regulatory regime for lines businesses prior to 2003 encouraged ratebase revaluation up to ODV, which was achieved by the network businesses over the first 6 years of reform. Thereafter, as market expectations factored in the lack of credibility of the light-handed regime, network assets changed hands at "fair value" levels, which included the discounted value of expected future regulatory tolerance. The market judgment in these transactions suggested that an actual contestability limit valuation would be of the order of $8.4 billion for all networks aggregated.

The essential issue raised by asset revaluations throughout the electricity sector was not the theoretical choice of valuation methodology per se; there are ample precedents around the world for both the historic-cost and the replacement-cost approach, with matching implications for the setting of the warranted rate of return on the resulting ratebase. The central issue was the New Zealand Government's decision to radically change the ratebase valuation methodology in asset mid-life, causing a dramatic levy (several billions of dollars) on the aggregate wealth of consumers, for the benefit of electricity suppliers. No protection was provided for consumers against this wealth expropriation. In particular, no regulatory provision required suppliers to compensate consumers for the wealth transfer, whether by means of rebates or through allocation of shares in the newly created equity value of suppliers.

In August 2001 Parliament passed a set of amendments to the Commerce Act 1986, giving the New Zealand Commerce Commission the task of regulating transmission and distribution lines networks. The Commission conducted lengthy hearings on the pricing practices of the electricity networks sector, and eventually decided to use the status quo of mid-2002 as its ratebase for future profit-cap regulation. The revaluations and widening margins of the 1990s were thereby retrospectively legitimized.[56] This regulatory outcome was inherited in 2003 by the new Electricity Commission.

7.5. The Electricity Commission: Back to An Industry Regulator

After more than a decade of experimentation with light-handed regulation, the New Zealand Government finally in 2003 followed the example of most other OECD countries by setting up a specialized industry regulator to oversee the electricity industry. The Electricity Commission is charged with a wide array of tasks: managing the ongoing information disclosure regime, setting price and revenue caps, coordinating the investment plans of various industry players, maintaining reserve generation capacity, overseeing industry governance arrangements, and guiding new investment by the issuing of "statements of opportunity", to name a few. Further privatization is off the policy agenda.

Several regulatory issues, however, remain unresolved:

- There is little prospect that the incumbent generators will be forced to divest their retail affiliates; yet without such divestment, new competitive retail entry remains foreclosed.
- Similarly, although Government has declared itself in favor of the rapid development of distributed generation, Transpower's grid pricing practices, which foreclose most opportunities for such projects, remain in place.
- Since 2002 a rush by large incumbent generators to build wind farms is raising a raft of difficult coordination problems, since the location of favorable sites for wind farms, and of the hydro generation assets that can be used to back-up wind generators, does not always coincide with the existing grid infrastructure, presenting the grid's operator, and the new regulator, with investment and coordination requirements not foreseen even a few years ago.

7.6. Conclusion: The State of Play at 2005

The structure of the industry in 2005 is shown in Figure 7.10. Of the 1989 Task Force recommendations, some have been implemented while others have been abandoned along the way. ECNZ has been broken into five separate generators (the Task Force had recommended against breakup). Only two of these generation companies are in private hands, while the Government continues to own 60% of generating capacity. The Task Force's fear that generation breakup without an industry regulator might result in losses of efficiency in the coordination of scheduling and investment seemed to have been borne out by 2002, and partly in response to this a new industry regulator was introduced in 2003.

Generation and transmission were separated early in the reform process, but the Task Force's proposal for club ownership of Transpower was rejected early on by industry participants, leaving the grid in state ownership.[57]

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[56] The Commission's deliberations are fully recorded at http://www.comcom.govt.nz/Industry Regulation/Electricity/ElectricityLinesBusinesses/Overview.aspx

[57] The Government attempted to implement the club proposal in 1992, but distributors refused to take part in the formation of a club in which their interests would have been diametrically opposed to those of generators, but in which they would not have had sufficient voting power to form a blocking coalition. The Task Force had failed to appreciate the likely extent of these conflicts of interest.

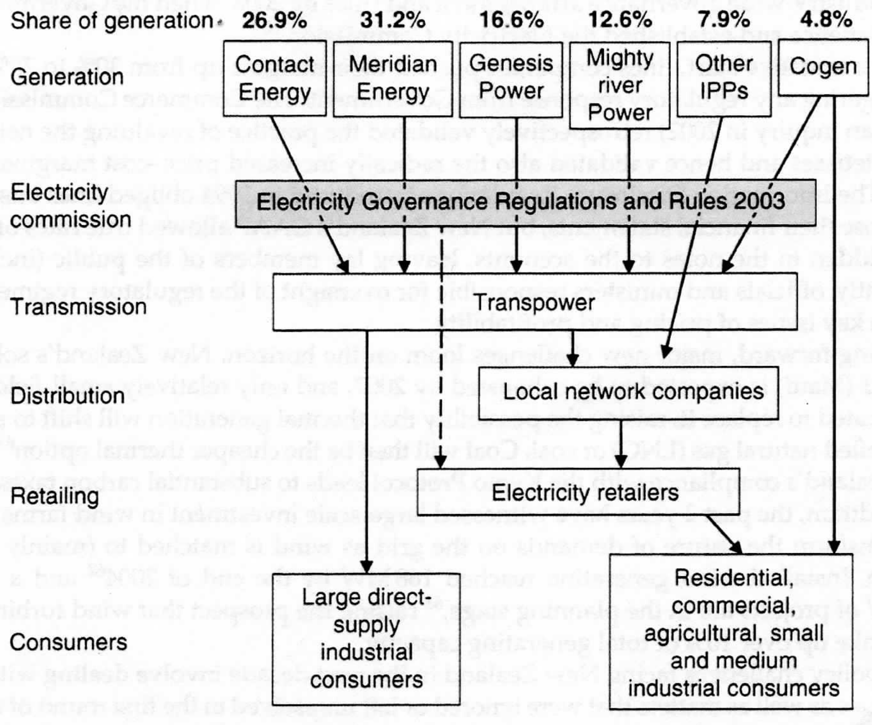

Fig. 7.10. Electricity industry structure 2004.

Corporatization of ESAs has been carried through, but less than half of distribution network assets have been fully privatized, and the interim trust-ownership arrangement has become entrenched in many rural and small-town systems. Retail franchises have been abolished and retail operators separated from lines networks, but competition at retail level quickly stalled once retailers and generators became vertically integrated.

No liquid market for hedge contracts has yet emerged – a defect still to be addressed by the new industry regulator. The main buyers in the wholesale market are the retail affiliates of generating companies, plus major manufacturers taking supply directly from the grid. Direct consumer exposure to spot market prices was estimated in 2003 to be no more than 10–15%,[58] which is not surprising given that the great bulk of the wholesale market is intra-firm.

Customer invoices continue to be presented without disaggregated line-item information that would enable consumers to identify the costs incurred at each stage of the supply chain – a level of information disclosure which the Task Force regarded as fundamental to retail competition, but which has never been mandated by Government.[59]

Possibly the most important lesson from the New Zealand experiment has been the failure of the Task Force's preferred model of light-handed regulation. Industry self-regulation under information disclosure failed comprehensively over a full decade of attempted implementation. Generators and distributors proved unable to agree on club governance for the grid in 1992–1994. Generators, distributors, retailers, and Transpower were unable to agree

[58] Commerce Commission, Decision number 491, www.comcom.govt.nz

[59] The New Zealand Commerce Commission, as *de facto* industry regulator from 2001 to 2003, repeatedly drew attention to this gap in the information disclosure arrangements, with no response from Government.

on an industry-wide governance arrangement and rules by 2003, when the Government ran out of patience and established the Electricity Commission.[60]

After a tentative start, lines companies pushed their margins up from 30% to 70% without triggering any regulatory response from Government. The Commerce Commission (following an inquiry in 2002) retrospectively validated the practice of revaluing the networks' asset ratebases and hence validated also the radically increased price–cost margins in that sector. The Information Disclosure Regulations introduced in 1994 obliged lines businesses to disclose their financial statements, but New Zealand's GAAP allowed true rates of return to be hidden in the notes to the accounts, leaving lay members of the public (including, apparently, officials and ministers responsible for oversight of the regulatory regime) in the dark on key issues of pricing and profitability.

Looking forward, major new challenges loom on the horizon. New Zealand's sole large gas field (Maui) is expected to be exhausted by 2007, and only relatively small fields have been located to replace it, raising the possibility that thermal generation will shift to reliance on liquefied natural gas (LNG) or coal. Coal will then be the cheaper thermal option[61] unless New Zealand's compliance with the Kyoto Protocol leads to substantial carbon taxes.

In addition, the past 2 years have witnessed large-scale investment in wind farms, which will transform the nature of demands on the grid as wind is matched to (mainly hydro) back-up. Installed wind generation reached 168 MW by the end of 2004[62] and a further 700 MW of projects are in the planning stage,[63] raising the prospect that wind turbines will soon make up over 10% of total generating capacity.

Key policy challenges facing New Zealand in the next decade involve dealing with these new issues as well as matters that were ignored or left unresolved in the first round of restructuring. These include the implementation of the Kyoto Protocol to which New Zealand is a party; opening up the demand side of the electricity market to new initiatives such as small-scale distributed generation, time-of-use metering and charging, and net metering of customers with their own generation capability; and breaking the logjam in retail competition. With an electricity regulator at last firmly established, there is an opportunity to make progress on these items of unfinished business.

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[60] Here again there are parallels with the German experience, discussed in Chapter 8.

[61] Mighty River Power is in the process of seeking planning permission to convert the mothballed oil-fired Marsden B power station to coal.

[62] http://www.windenergy.org.nz/FAQ/proj_dom.htm

[63] http://www.windenergy.org.nz/

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