# Rents in the New Zealand Energy Sector

*Geoff Bertram Victoria University*

This paper discusses the nature and origins of rents as a category of income arising from the working of markets, with illustrations drawn from the New Zealand energy sector, and then considers how such rents are distributed, whether by allocation to specific individuals or groups, or by being "dissipated".

A rent arises in any situation where some resource or commodity is in fixed, limited supply and can be hired out or sold for a price higher than the supplier's minimum reserve price. Rents fall into several categories depending upon the cause and nature of the scarcity which gives rise to them. We may distinguish:

- pure scarcity rents accruing to land or other natural resources in fixed supply, when demand for the services of those resources exceeds the cost of making them available. The New Zealand market for kauri and high-grade heart rimu timber currently exhibits rents of approximately this type, as continuing demand for such timber for specialty uses presses against the limited supply from a nearly-depleted resource which is subject to competing demands from conservation and tourism uses. In the long run (100 years+) native forests are of course reproducible on an expanded scale; but the growth cycle is long enough, given the absence of large-scale replanting in the past half-century, to render the forests containing high-grade native timbers effectively a resource in fixed and scarce supply. Another, internationally-familiar, example is fisheries, where fish stock and the maximum rate of biological reproduction set limits to the size of the sustainable catch, and where the absence of an agency to appropriate rents is apt to lead to overfishing (Gordon 1954).
- differential rent, which accrues to low-cost suppliers in any industry where not all suppliers have the same unit costs. Two types of differential rent may be distinguished. First is so-called "Ricardian rent" accruing to some producers in an industry on account of their control of especially productive or well-located natural resources. In the New Zealand

energy sector the major example is hydro electric generating sites, with prime sites near major centres of consumption—for example, the Waikato River—yielding high rents to the scarce combination of water-flow and topography. Another example is the Kapuni natural gas field which, as a low-cost onshore operation, secures Ricardian rent in a New Zealand market where the price of gas is set to render the offshore Maui field profitable. A second type of differential rent which verges on quasi-rent (see below) is analysed in Salter (1966) and may be designated "Salter rent". This applies to the case of a capital-intensive industry where the costs of entry are high because of the need for any new entrant to invest a large sum to build a single plant. Existing firms in the industry, who have already incurred their investment costs, are sheltered by this barrier to entry because their current operating costs per unit of output are well below the long-run unit cost (including capital costs) which face new entrants. Amortisation and the return on investment of existing firms in any industry (not just natural-resource-based sectors) are covered by the Salter rents or quasi-rents they earn on their sunk investment costs.

- quasi-rents, which accrue to the owner of a reproducible productive asset which is in fixed supply in the short run, but open to competitive entry in the long run. These rents tend to erode over time (hence the "quasi"), as competing producers are attracted in, and prices are bid down, by the high profitability resulting from the rent. In New Zealand's energy sector, one case study of quasi-rents which has been researched is the retailing of CNG in the period when only a limited number of service stations were equipped for the trade (Ellis 1983).
- monopoly rents, which accrue to the owner of an activity licensed and protected by government, or protected by the enterprise's own deployment of market power. The protected status (to date) of the Marsden Point oil refinery generates rents of this kind (albeit they are mainly dissipated in running a high-cost refinery) (Barr and Gaudin 1985). The monopoly control over the Kapuni and Maui gasfields by the Shell-BP consortium, under New Zealand's prevailing licensing regime, may also generate monopoly rents (Bertram, 1978, p.293). (One hypothetical alternative would be

to have a number of separate companies owning and operating the two fields in competition with each other; if no cartel were formed, competition would theoretically drive the price down to the marginal producer's cost of supply. In practice, "no cartel" is a very strong and usually unrealistic assumption.) On a world scale, the major example in the past decade has been the ability of OPEC to command high oil prices during the period of time required for alternative sources of supply, and energy-saving investments in consuming countries, to come on-stream. (In the longer-run, OPEC's monopoly has proved "contestable". In the very long run, pure scarcity rents should again give Middle East producers high returns on their oil, assuming no comparable new oil province is discovered.)

To some extent, thus, whether a particular stream of income is viewed as a rent or not depends on the time-scale of the analysis. The high profits from a known oilfield, for example, appear as rents for the period of exploitation; but without the expectation of such a level of profitability should oil be struck, the original exploration effort might not have occurred. Resources requiring to be found by exploration before they can be exploited, and technologies which must be invented and developed before they can contribute to production, are cases where rents have a "socially useful" function as an incentive to further exploration or research.

Indeed it is generally true that the key incentives in a growing and/or changing economy are provided by the rents which entrepreneurs anticipate winning if their ventures are successful. New industrial investment is motivated by the quest for quasi-rents, mineral exploration by the quest for scarcity and/or Ricardian rents. Without rents, or the hope of them, a capitalist economy would lack its mainspring.

*A rent exists, then, whenever the consumer of a commodity is obliged to pay more than the cost of supplying that commodity from the cheapest existing source.* In free markets, the price is expected to settle at roughly the cost of production from the *marginal*, not the *cheapest*, source of supply. Therefore in any free-market situation there will be rents gained by the owners of relatively low-cost ("intra-marginal") supplies. Rents will be entirely absent only when all firms in an industry have identical unit costs, and when the product sells for a price which is just equal to cost.

It follows that the gaining of rents is an intrinsic part of the efficient functioning of the market mechanism—there is no *necessary* incompatibility between rents and market efficiency. Such incompatibility *may* arise, however, in the case of monopoly rents, especially where these are not sanctioned by society in the interests of overall economic efficiency. The allocation of rents may also, of course, raise important issues of equity.

In the sections which follow, we shall first look more closely at how rents arise; then consider how they may be allocated or dissipated; and then identify issues relating to incentives, efficiency and equity in the New Zealand energy sector.

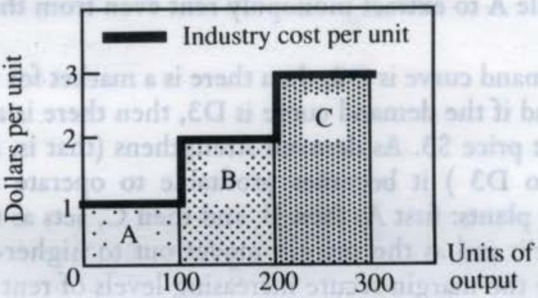
## Differential Rent: Some Simple Economic Theory

Rents arise first from the fact that not all economic resources are of equal productive capacity, and second from the fact that many real-world market structures are characterised by some "degree of monopoly" (market power). Either or both of these two elements may be encountered in any specific situation.

To show how rents are conceptualised and measured, it is useful to begin with a simple model of differential rent in an industry which has three producing units of unequal productivity. Suppose that A, a low-cost producer, has production costs (including "normal profit"—that is, the opportunity-cost of mobile or "footloose" capital employed) of $1 per unit, while B, the moderate-cost producer, has unit costs of $2, and C, the high-cost producer, has unit costs of $3. Suppose further that all three plants have productive capacity of 100 units of output per week, and that each plant can produce either its full output or none (this assumption is merely convenient, not essential; for a more sophisticated version of the story see Salter 1966 p.78). We can then draw Figure 1, showing the cost and output capabilities of the three units side-by-side. The resulting heavy black line is an "industry supply curve" in the sense that this concept is used by Salter (1966 Chapters IV—VI) (see also Parmenter and Webb 1974).

The position is then that if the product is selling for a price of $3 per unit or more, all three plants can be operated profitably. If the price falls to a level below $3 but above $2, then plants A and B are profitable but plant C, if operated, would make a loss. If the price

FIGURE 1: Industry supply curve



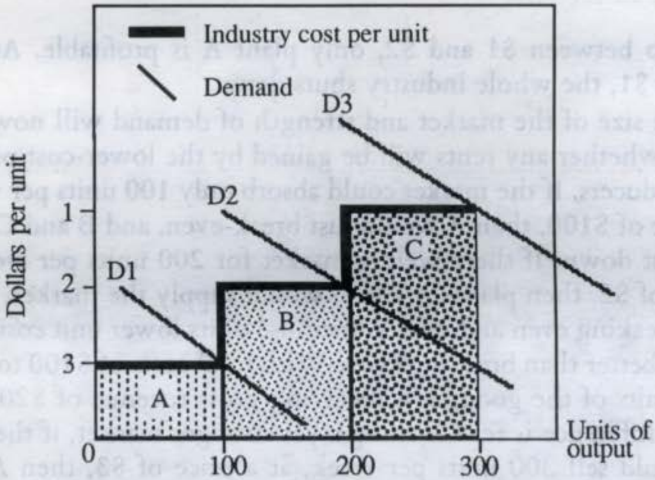

falls to between $1 and $2, only plant A is profitable. At prices below $1, the whole industry shuts down.

The size of the market and strength of demand will now determine whether any rents will be gained by the lower-cost producer or producers. If the market could absorb only 100 units per week at a price of $100, then A would just break-even, and B and C would be shut down. If there were a market for 200 units per week at a price of $2, then plants A and B would supply the market, with B just breaking even and with A (because of its lower unit cost) doing much better than breaking even. With total costs of $100 to supply 100 units of the good, A is receiving gross revenue of $200. This $100 difference is rent. Taking a yet stronger market, if the industry could sell 300 units per week, at a price of $3, then A's rent income would rise to $200, and plant B would now become also an "intra-marginal" supplier, earning rent of $300–$200=$100.

In economics it is usually taken for granted that the size of the market for a good varies inversely with its price: price-cutting attracts in more buyers, while price increases drive some potential buyers away. This idea gives the "demand curve", which can be superimposed on the industry supply curve to give the "market price" and "market quantity" at which demand and supply are in balance with each other. Figure 2 shows three possible demand curves, corresponding to the three situations outlined in the preceding paragraph. If the demand curve is D1, then there is a market for 100 units at price of \$1. More than 100 units could be sold only if price were reduced below \$1. Plant A is therefore the only possible supplier, and will receive no rent (given our assumption that plant output must be 100 or nothing. A more flexible output would enable A to extract monopoly rent even from this market—see below).

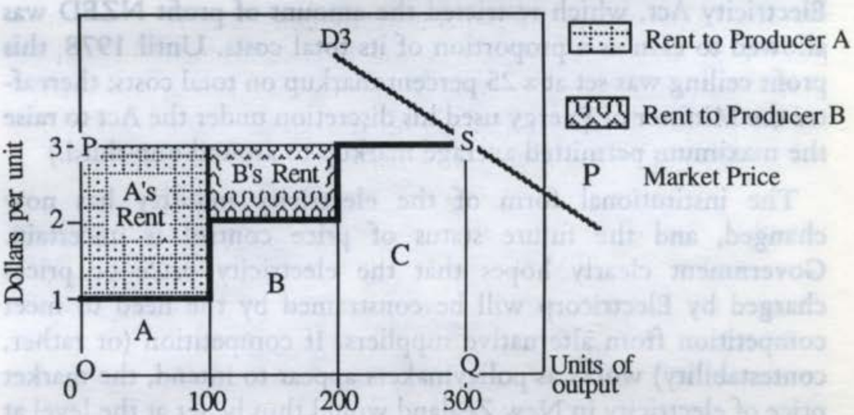
If the demand curve is D2, then there is a market for 200 units at price \$2; and if the demand curve is D3, then there is a market for 300 units at price \$3. As demand strengthens (that is, as we move from D1 to D3 ) it becomes profitable to operate successively higher-cost plants: first A, then B, and then C, acts as the "marginal supplier"; and as the margin moves out to higher-cost plants, those inside the margin secure increasing levels of rent income.

FIGURE 2: Demand curves and industry supply curve




Take, for example, the state of market demand represented by the demand curve D3 (see Figure 3). The market price is p, so the market can now accommodate all three producers, with C operating at the margin and both A and B receiving rents. The total cost of supplying 300 units per week to the market is obtained by adding up the three rectangles A+B+C—in other words, total cost is the area enclosed below the industry supply curve. In the example, this comes to 100+200+300 = 600. Total revenues from sale of the good are given by the area of the rectangle OPSQ, price times total quantity; in this case, 300 × 3 = 900. Total rents are the difference between revenues and costs (900-600 = 300) and these rents are distributed between A and B according to the sizes of the shaded rectangles [A's rent] and [B's rent].

FIGURE 3: Rents to producers with different supply costs




To show how these ideas apply in practice, we can take two examples of energy-supplying industries in New Zealand for which research has been done: electricity generation and CNG retailing.

# Some New Zealand Examples

## 1 *Electricity Generation*

The production of electricity in New Zealand has been dominated since the 1920s by the NZ Electricity Division (NZED), reorganised in 1986-87 as State-Owned Enterprise Electricorp. This organisation owns and operates some 30 hydroelectric stations and 8 thermal power stations, all of which are tied together in a single nation-wide system, the National Grid. The system is operated with the aim of supplying electricity as cheaply as possible from the available generating capacity, subject to the constraint that allowance must always be made for actual or possible variations in rainfall (and hence in the volumes of water available for hydroelectric generation).

Price control on the "bulk tariff" at which NZED sold its power prevented the organisation from exploiting its consumers by pushing up the price to obtain monopoly rents. (This price control operated through the mechanism set out in Section 34(1) of the Electricity Act, which restricted the amount of profit NZED was allowed to earn as a proportion of its total costs. Until 1978 this profit ceiling was set at a 25 percent markup on total costs; thereafter the Minister of Energy used his discretion under the Act to raise the maximum permitted average markup to around one-third.)

The institutional form of the electricity industry has now changed, and the future status of price control is uncertain. Government clearly hopes that the electricity price or prices charged by Electricorp will be constrained by the need to meet competition from alternative suppliers. If competition (or rather, contestability) works as policymakers appear to intend, the market price of electricity in New Zealand would thus be set at the level at which it is not profitable for anyone to build a new power station to compete with existing suppliers. Given the very large indivisible investment costs of new generating stations, and the fact that existing suppliers are operating with large sunk costs and may be able to engage in lengthy price wars to hold their market share, this is at best a blunt instrument—but it may prove a suitably menacing one to hold prices in the long run reasonably close to (i.e. just below) the "marginal cost of supply"—that is, the price at which it is just worth installing new generating capacity.

For the purposes of the present paper, the significant feature of the electricity industry is that it exhibits rising marginal cost of supply up to somewhere near the existing scale of output, but fairly constant marginal costs for increasing levels of supply. The reason for this is that there exist several technologies for generating large quantities of electricity at a fairly standard best-practice cost. One of these technologies is thermal generation fired by coal, gas or oil. In the near future, coal-fired or gas-fired thermal stations are the most likely new marginal additions to the electricity system in New Zealand, given uncertainties over long-run world oil prices.

The reason why New Zealand has to date had cheaper electricity than many overseas countries is that the country is endowed with natural resources which produce electricity at less than its "world marginal cost". These resources—river gorges, geothermal steam, shallow coalfields, natural gas—have by now mostly been developed for electricity, or allocated to other competing uses (ranging from wild and scenic river preservation to domestic reticulation of gas). The investment costs of developing these resources for electricity generation have been incurred in the past—they are "sunk costs"—so that effectively we can treat the dams, powerhouses, boilers and turbines as extensions of the natural resources themselves—as assets bequeathed to present users by the past. When electricity from these sources is sold, any revenue in excess of current operating costs is effectively rent. It is from these rent incomes that the electricity generating industry finances the servicing and repayment of past loans, the building of new power stations, and any payments of taxes and profits to Government (the present owner).

The large operating surplus characteristic of NZED in the past, and of Electricorp today, is thus to be interpreted as differential rent "earned" by low-cost intra-marginal stations in the national system.

An idea of the orders of magnitude involved can be gained from the financial results of NZED in its last year of operation, 1985-86 (Annual Statistics, 1986, table iv p.2). In that year 26,000 gigawatt-hours (Gwh)of electricity were generated from the thirty operating stations, and sold for roughly $1,068 million—an average revenue of 4.1 cents per kilowatt-hour. [A gigawatt-hour is 1 million kilowatt-hours.] (This average price is less than the bulk tariff because of the inclusion of the Comalco aluminium smelter and one or two other special low-price customers.) Of the 26,000 GWh total, about 18,700 GWh came from hydro stations and 7,300 GWh from thermal stations (including geothermal). The working and administrative costs of the hydroelectric stations totalled $63 million, or around 0.34 cents per kilowatt-hour. The corresponding figures for the thermal stations were total working and administrative costs of $266 million, giving average unit operating costs of 3.65 cents per kilowatt-hour. Working and administrative costs of running the transmission lines and substations of National Grid totalled $69 million (about 0.27 cents per kilowatt-hour of electricity), bringing total operating costs to $398 million, and leaving roughly $670 million of operating surplus to pay for interest, depreciation, and profits. (Of this, $62 million was spent on loan repayments, $366 million was paid as interest, $78 million was allocated to depreciation, and $164 million remained as net profit.)

Interpreting these numbers in the framework of Figure 3 above, we could treat the hydro system as producer "A" and the thermal stations as a group as producer "B". Adding the system overhead operating costs of 0.27 cents per kWh to the average unit operating cost of the generating stations, we would have average unit cost for the hydro system of 0.61 cents per kilowatt-hour and average unit cost for the thermal system of 3.92 cents per kWh. (Annual unit-operating-cost data are shown in Table 1. These costs exclude capital charges.)

TABLE 1: Unit operating costs of the New Zealand electricity generating system

| | *Working and Administration Costs of Generation, Cents/kWh* | | |
|---|---|---|---|
| *Year to March* | *Hydroelectric stations* | *Thermal stations* | *All generating stations combined* |
| *1983* | 0.17 | 2.17 | 0.70 |
| *1984* | 0.23 | 2.60 | 0.76 |
| *1985* | 0.25 | 2.65 | 0.87 |
| *1986* | 0.34 | 3.65 | 1.27 |

In a simple story which ignored the real-world detail of the electricity industry, we would then have a product which cost roughly 3.9 cents per unit from the high-cost producer and sold for 4.1 cents per unit, so that the thermal "plant" roughly broke even. The lower-cost hydroelectric "plant", however, had unit costs of only 0.61 cents, and therefore secured rent of (4.1—0.6) = 3.5 cents per kWh, or a total of $655 million. On this basis, therefore, virtually all NZED's operating surplus would have constituted differential rent to the producing units based on the cheap hydroelectric resource. To credit all this as rent to the hydroelectric system would, however, understate the actual contribution of the thermal stations to overall profitability, because if the thermal stations did not exist to provide dry-year security of supply, the hydroelectric generating sector would have to be larger, with roughly 15 percent excess capacity in normal-rainfall years.The existence of thermal stations is what permits the hydro system to operate at 100 percent capacity in mean years; in the calculations which follow, we have therefore "credited" 15 percent of the revenue from hydro-generated electricity to the thermal system, and 85 percent to the hydro system.

Table 2 presents calculations on this basis for the four years 1982/3-1985/6. We have taken total revenues from sales of electricity, and subtracted all the operating costs of the electricity system including expenditure on buying-in electricity from independent suppliers (an item of negligible significance relative to the totals). This gives the operating surplus for the system as a whole. We then allocate this operating surplus between hydro and thermal stations by repeating the calculation for each block of generation, incorporating the crediting of 15 percent of hydroelectricity revenues to the thermal system for reasons just discussed, and assuming that all electricity from both sources was sold for a uniform price. (In fact, hydro electricity was sold for a lower average price than thermally generated electricity. This is power due to the Manapouri-Comalco contract for sale of electricity from the Manapouri hydroelectric station to the Comalco aluminium smelter at Bluff at a very low price. This detail does not change our aggregate rent estimate, though it affects its allocation between hydro and thermal stations.)

The system's total operating surplus, thus calculated, is \$462 million in 1983/84, rising to \$633 million in 1985/86. The fact that the great bulk of this accrued to the low-operating-cost hydro block of generating capacity confirms that the dominant reason for the profitability of the system is differential rent.

How much of the operating surplus can be treated as rent? As an approximation, we shall take the total surplus minus the "normal rate of profit" on mobile capital which, if not paid this rate of return, would leave the industry. Dams and turbines, once built, are not footloose (that is, they will not shift to other uses if they cease to earn a return on their capital costs) but some parts of the capital invested in the electricity system would certainly have positive "transfer earnings" (that is, could secure a return in alternative uses) and allowance should be made for this. Unfortunately, we do not have the data to conduct this exercise. The net book value of NZED's "completed works" (that is, stations actually generating power, and operating transmission systems) in 1985-86 was around \$3 billion (Annual Statistics..... 1986 , p.2), so that if we were to allow for, say, a 10 percent "normal" return on this total, nearly half the total operating surplus would appear as "normal profit"

TABLE 2: Differential profitability in the electricity sector

*Part 1: Total system*

| *Year to March* | *(1) Total electricity generated GwH* | *(2) Total sales revenue $ million* | *(3) Working and administrative costs of generating stations $ million* | *(4) Non-generation working and administration costs incl purchase of power $ million* | *(5) Total hydro and thermal operating surplus $ million (2)-(3)-(4)* |
|---|---|---|---|---|---|
| *1983* | 23,619 | 712 | 166 | 84 | 462 |
| *1984* | 24,997 | 760 | 191 | 59 | 510 |
| *1985* | 25,754 | 827 | 224 | 62 | 541 |
| *1986* | 25,986 | 1,033 | 330 | 70 | 633 |

*Part 2: Hydroelectricity stations*

Hydroelectric generating stations as a group:

| *Year to March* | *(1) Electricity generated GwH* | *(2) Adjusted share of total revenues* $ million* | *(3) Working and administration costs $ million* | *(4) Pro-rata share of non-generation operating costs (incl purchases) $ million* | *(5) Operating surplus $ million (1)-(3)-(4)* |
|---|---|---|---|---|---|
| *1983* | 17,321 | 444 | 30 | 62 | 352 |
| *1984* | 19,358 | 500 | 45 | 45 | 409 |
| *1985* | 19,115 | 522 | 48 | 46 | 428 |
| *1986* | 18,688 | 631 | 63 | 50 | 518 |

*Part 3: Thermal Stations*

Thermal generating stations as a group:

| *Year to March* | *(1) Electricity generated GwH* | *(2) Adjusted share of total revenues* $ million* | *(3) Working and administration costs $ million* | *(4) Pro-rata share of non-generation operating costs (incl purchases) $ million* | *(5) Operating surplus $ million (1)-(3)-(4)* |
|---|---|---|---|---|---|
| *1983* | 6,298 | 268 | 137 | 22 | 109 |
| *1984* | 5,639 | 260 | 147 | 13 | 100 |
| *1985* | 6,638 | 305 | 176 | 16 | 113 |
| *1986* | 7,298 | 401 | 266 | 20 | 115 |

*15% of hydro revenues credited to thermal to reflect its contribution to system security

*Source:* Annual Statistics in Relation to Electricity Construction, Generation and Supply for years shown.

rather than rent. But because the great bulk of this sunk capital is not mobile, its actual transfer earnings are extremely low (just the scrap value of the materials and plant) and accounting conventions such as a required return on book value of assets fail to meet the economic definition of rent. As a very rough guess we might suppose that perhaps $50 million of the operating surplus might credibly be classed as transfer earnings, and therefore excluded from the category of "rent". The 1985/86 operating surplus of $633 million would then consist of $50 million of transfer earnings of capital, and $583 million of differential rent.

One further problem is posed by the fact that the electricity from the largest (and almost the cheapest) hydroelectric station Manapouri is sold to the Bluff aluminium smelter at a price less than half the wholesale price to other bulk-electricity buyers. Part of the potential rent from the hydro system is thus not collected as revenue, but rather is passed on, via lower electricity prices, to the partners in the Bluff smelter and to the world's aluminium users. (The rationale for this arrangement in the past was that the "potential rent" could not be realised in practice because of the remoteness of Manapouri from the country's main electricity markets. As this rationale has faded with expansion of demand and improvement of the National Grid, so government has been able to raise the price of power to the Bluff smelter.) The amount of rent thus "missing" from Table 1 on account of its dissipation via the Bluff smelter is extremely difficult to estimate, but would have lain somewhere between $10 million and $50 million in 1985-86.

There is of course a wide range of operating costs amongst individual hydro and thermal stations, and a fuller attempt to estimate rents needs to look at the station-by- station picture. In Figure 4 and Table 3 below is shown the way in which greater real-world detail can be incorporated for the 1983/84 year. The diagram has two components: first, a left-hand segment which shows the special situation relating to Manapouri and the Bluff smelter, and then a right-hand segment which shows the remainder of the electricity sector (including Manapouri power over and above that used by the smelter). Starting from the flat low-cost plateau representing Manapouri, the industry supply curve (showing the short-run marginal cost of supply) slopes up to the right as one after another of the higher-cost generating stations are brought into the picture.

To draw Figure 4, in the absence of official data relating to the Bluff smelter, we assume that in 1983/84 the smelter used 3,900

GWh at an average price of 1.5 cents/kWh. This then leaves the remaining 21,000GWh produced and sold receiving average revenue of 3.05 cents/kWh, net of system overheads. Operating surpluses secured are shown by the shaded area in Figure 4, and are calculated station-by- station in Table 3. The total is of course the same (bar some rounding errors) as in Table 1, since all we are doing is analysing the system's operating surplus in greater detail. The more thorough approach in Table 3, however, identifies the fact that among the thermal stations Wairakei, Huntly, New Plymouth and Stratford together secured surpluses totalling \$53 million, while Meremere, Whirinaki, Otahuhu and Marsden A aggregated minus \$30 million. We have not attempted in Table 3 the earlier 15 pecent adjustment in the allocation of operating surplus between hydro and thermal.

The theoretical structure underpinning Table 3 and Figure 4 is illustrated in Figures 5 and 6 below. In Figure 5, the demand curve in the right-hand quadrant is the demand by all electricity users other than the Bluff smelter. A controlled wholesale price (bulk tariff) of p* has been imposed at a level which is below the "market-clearing" price at which the demand and supply curves in the right-hand quadrant intersect. Assuming that transfer-earnings on capital have been incorporated in the curves, the total surpluses "earned" by the system then consist of the rents from the Manapouri bulk sale at price pm (area M) *plus* rents from all other generating capacity with unit operating costs lower than the bulk tariff (area N) *minus* the losses (negative rents, area L) from those stations which have operating costs above the bulk tariff, but are nonetheless operated to satisfy the market demand q* at the bulk tariff. (This, obviously, is not an operation running according to strictly commercial criteria.)

TABLE 3: Calculating operating surplus by individual stations, 1983/84

Results for the 1983/84 year

| *Stations* | *Power produced 000 kWh* | *Working expenses excl admin $000* | *Fuel $000* | *Admin charges $000* | *Total O&M costs 000 $* | *Per-unit O&M ¢ per kWh* | *Revenues @3.05¢ except Comalco (1.5¢) $000* | *Surplus $000 (see note j)* |
|---|---|---|---|---|---|---|---|---|
| *Ohau B*[a] | 105,496 | 54 | 0 | 83 | 83 | 0.08 | 3,218 | 3,134 |
| *Benmore* | 2,629,812 | 1,513 | 0 | 2,317 | 2,317 | 0.09 | 80,209 | 77,893 |
| *Manapouri I*[b] | 3,900,000 | 2,255 | 0 | 3,454 | 3,454 | 0.09 | 58,500 | 55,046 |
| *Manapouri II*[c] | 927,102 | 536 | 0 | 821 | 821 | 0.09 | 28,277 | 27,456 |
| *Lake Coleridge* | 247,075 | 161 | 0 | 247 | 247 | 0.10 | 7,536 | 7,289 |
| *Tekapo B*[d] | 914,154 | 660 | 0 | 1,011 | 1,011 | 0.11 | 27,882 | 26,871 |
| *Ohau A*[e] | 1,130,394 | 794 | 0 | 1,216 | 1,216 | 0.11 | 34,477 | 33,262 |
| *Aviemore* | 1,124,001 | 771 | 0 | 1,181 | 1,181 | 0.11 | 34,282 | 33,101 |
| *Roxburgh*[f] | 1,792,452 | 1,486 | 790 | 2,276 | 2,276 | 0.13 | 54,670 | 52,394 |
| *Rangipo*[g] | 334,982 | 326 | 0 | 499 | 499 | 0.15 | 10,217 | 9,718 |
| *Maraetai* | 763,627 | 1,125 | 0 | 1,724 | 1,724 | 0.23 | 23,291 | 21,567 |
| *Waitaki* | 608,810 | 1,091 | 0 | 1,670 | 1,670 | 0.27 | 18,569 | 16,898 |
| *Whakamaru* | 457,851 | 1,087 | 0 | 1,664 | 1,664 | 0.36 | 13,964 | 12,300 |
| *Aratiatia*[h] | 309,055 | 720 | 0 | 1,103 | 1,103 | 0.36 | 9,426 | 8,323 |
| *Matahina* | 282,948 | 720 | 0 | 1,102 | 1,102 | 0.39 | 8,630 | 7,528 |
| *Arapuni* | 760,555 | 1,952 | 0 | 2,989 | 2,989 | 0.39 | 23,197 | 20,208 |
| *Tokaanu*[i] | 800,805 | 2,175 | 0 | 3,332 | 3,332 | 0.42 | 24,425 | 21,093 |
| *Tekapo A* | 169,192 | 487 | 0 | 745 | 745 | 0.44 | 5,160 | 4,415 |
| *Atiamuri* | 268,529 | 829 | 0 | 1,269 | 1,269 | 0.47 | 8,190 | 6,921 |
| *Waipapa* | 230,533 | 717 | 0 | 1,098 | 1,098 | 0.48 | 7,031 | 5,934 |
| *Ohakuri* | 375,320 | 1,226 | 0 | 1,878 | 1,878 | 0.50 | 11,447 | 9,569 |
| *Karapiro* | 486,971 | 1,773 | 0 | 2,716 | 2,716 | 0.56 | 14,853 | 12,137 |
| *Cobb* | 179,134 | 957 | 0 | 1,466 | 1,466 | 0.82 | 5,464 | 3,997 |
| *Wairakei* | 1,150,101 | 8,407 | 0 | 10,732 | 10,732 | 0.93 | 35,078 | 24,346 |
| *Waikaremoana* | 343,769 | 2,941 | 0 | 4,504 | 4,504 | 1.31 | 10,485 | 5,981 |
| *Highbank* | 53,290 | 701 | 0 | 1,073 | 1,073 | 2.01 | 1,625 | 552 |
| *Huntly* | 1,298,320 | 6,979 | 12,538 | 26,409 | 26,409 | 2.03 | 39,599 | 13,190 |
| *Mangahao* | 92,704 | 1,327 | 0 | 2,032 | 2,032 | 2.19 | 2,827 | 795 |
| *New Plymouth* | 2,265,137 | 11,066 | 37,337 | 55,337 | 55,337 | 2.44 | 69,087 | 13,750 |
| *Stratford* | 507,411 | 3,270 | 9,483 | 13,397 | 13,397 | 2.64 | 15,476 | 2,079 |
| *Monowai* | 43,279 | 765 | 0 | 1,172 | 1,172 | 2.71 | 1,320 | 148 |
| *Arnold* | 26,647 | 1,089 | 0 | 1,668 | 1,668 | 6.26 | 813 | −855 |
| *Meremere* | 268,233 | 7,045 | 9,006 | 20,076 | 20,076 | 7.48 | 8,181 | −11,895 |
| *Whirinaki* | 9,028 | 353 | 363 | 793 | 793 | 8.79 | 275 | −518 |
| *Otahuhu* | 55,373 | 2,000 | 1,835 | 5,410 | 5,410 | 9.77 | 1,689 | −3,721 |
| *Marsden A* | 85,222 | 5,105 | 8,260 | 15,977 | 15,977 | 18.75 | 2,599 | −13,378 |
| *Totals* | 24,997,311 | 91,379 | 78,823 | 50,150 | 220,352 | 0.00 | 760,187 | 507,527 |

*TABLE 3: Calculating operating surplus by individual stations, 1983/84—continued*

*Notes:* a. Incl 4.9% of Twizel Control.
b. Sales to Bluff smelter.
c. Remaining Manapouri power not sold to smelter.
d. Incl 42.5% of Twizel Control.
e. Incl 52.6% of Twizel Control.
f. Incl Wakatipu & Hawea controls.
g. Incl 29.5% of Tongariro control.
h. Incl Taupo control.
i. Incl 70.5% of Tongariro control.
j. Surplus includes an unknown, but probably not very large, amount of "normal profit" on mobile capital; and is not corrected for the interdependence of thermal and hydro generation.

*Sources:* NZED, *Annual Statistics*; plus NZED, *Annual Generation Costs, Year Ended 31 March 1984* (unpublished). Note that generating costs by station appeared in the Annual Report of the NZED for years up to 1982/83 but have not been published since. The 1983/84 figures above were released but not published by NZED.

Figure 6 shows how the situation in Figure 5 would be modified if a uniform market-clearing price, p', were charged for all electricity supplied, including power for the Bluff smelter. The total surplus would be increased by extra rent from Manapouri (area W) plus extra rent from intramarginal stations (area X), *plus* the losses no longer incurred by supplying excess demand (area L). The strict, "perfect" free-market situation of Figure 6 yields total rents (M+W+N+X) which are larger than the rents obtained under the status quo (M+N-L). Total electricity consumption is cut back from q* to q', saving costs which would otherwise have to be incurred to meet marginal demand from high-cost marginal stations.

FIGURE 4: New Zealand Electricity Division operating cost and surplus, by Station, 1983/84

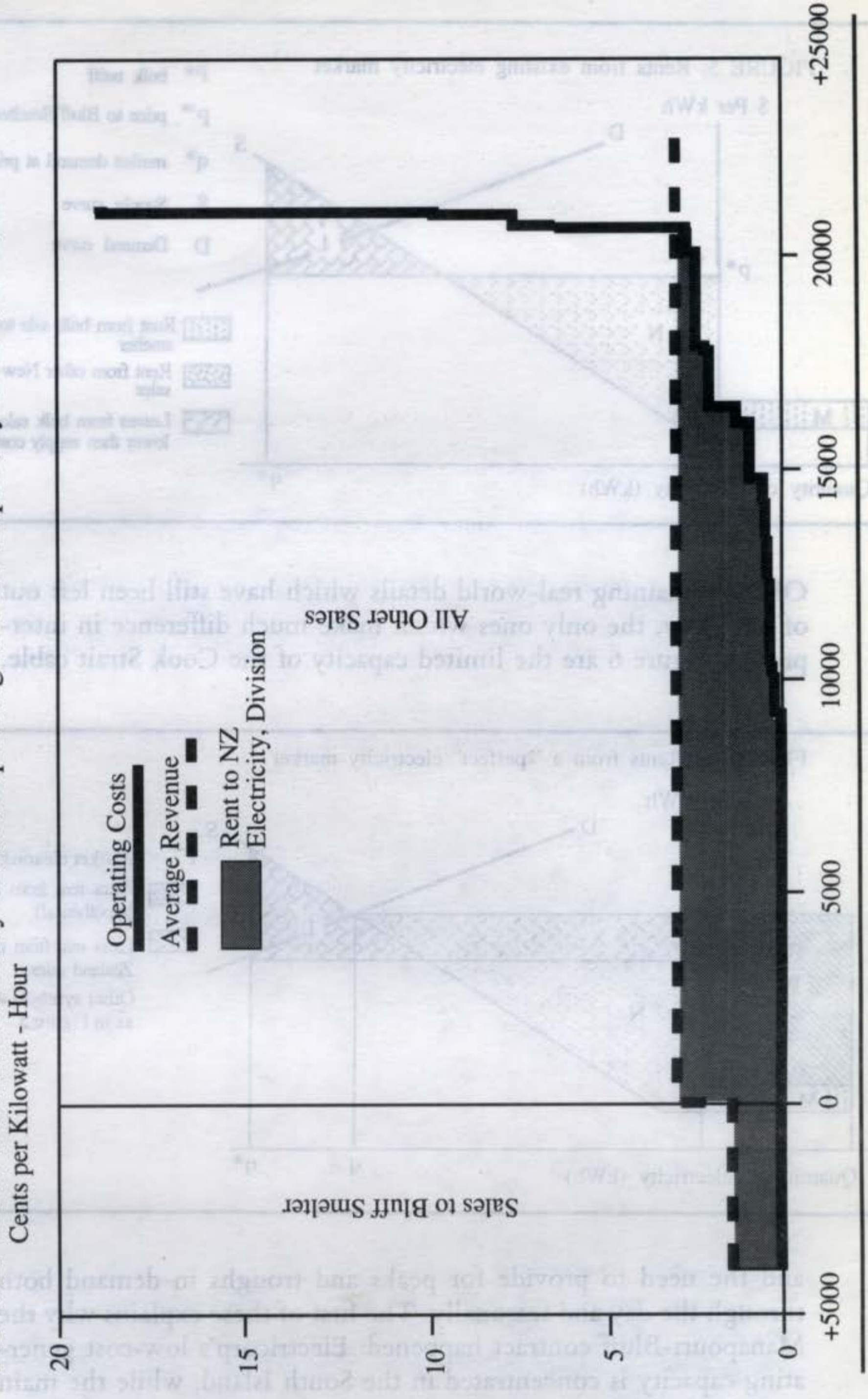
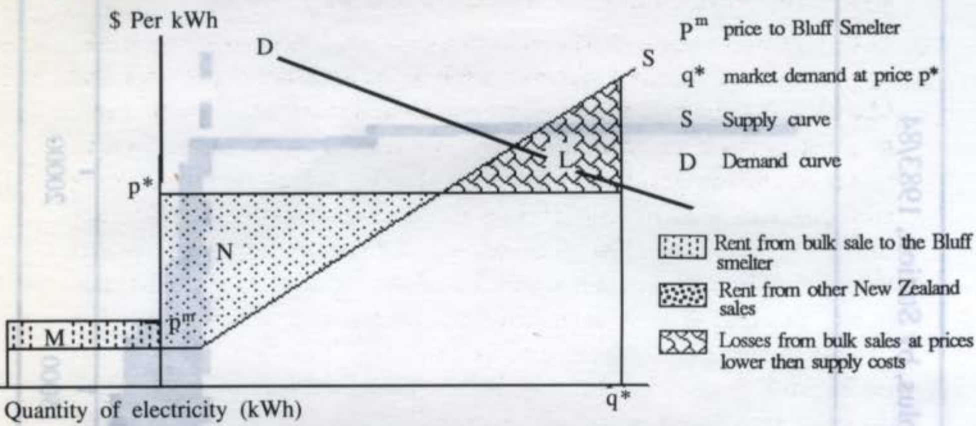
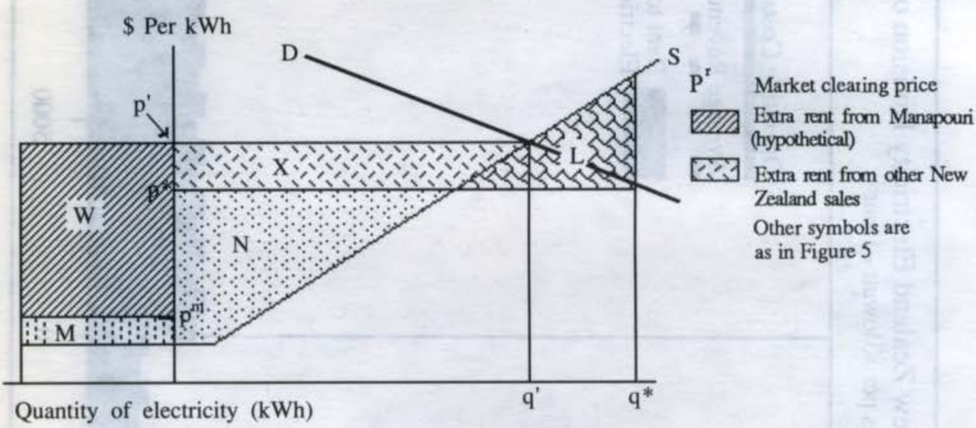


FIGURE 5: Rents from existing electricity market




Of the remaining real-world details which have still been left out of our story, the only ones which make much difference in interpreting Figure 6 are the limited capacity of the Cook Strait cable,

FIGURE 6: Rents from a ``perfect'' electricity market




and the need to provide for peaks and troughs in demand both through the day and seasonally. The first of these explains why the Manapouri-Bluff contract happened: Electricorp's low-cost generating capacity is concentrated in the South Island, while the main markets for electricity are in the North Island. The market-wide free-market price p' could thus only arise if the Cook Strait cable were large enough not to pose a constraint on inter-island transmission of power, and if such transmission was costless.

The second issue—peaks and troughs—explains why very high-operating-cost thermal stations such as Whirinaki, Otahuhu and Marsden A exist and would continue to be used from time to time, to meet periods of especially high demand. Figure 5 is drawn in terms of annual quantities of energy (kWh), but electricity is actually purchased as a flow of kilowatts, and low-cost stations are limited in the rate at which they can produce electricity. When therefore, the rate of use exceeds the flow capacity of low-cost stations, the higher-cost marginal stations must be brought into the system if power cuts are not to be required. The demand curve D in Figures 4 and 5, thus, must be thought of as an "average" demand curve and p' as an "average" price. The actual demand curve shifts in and out in the course of each day, and it is this feature of the system which presents the major analytical challenges for the managers of any electricity supply system (cf Electricorp 1987). By using figures on actual unit costs incurred over the course of a typical year and average revenues earned, we can abstract from this issue without losing too much. It needs always to be remembered, however, that before drawing strong conclusions about how the market for electricity *ought* to be organised and regulated, it is necessary to come to terms with the physical and engineering realities of the system.

The significance of the existence of large differential rents in the electricity sector has recently come to the fore because of the decision to corporatise the old NZED under the name Electricorp. The government, acting as the owner of the assets of NZED, proposes to transfer those assets to Electricorp at a price which corresponds to the present value of the rents (net revenues) likely to be earned by Electricorp in a market environment in which its possible competitors will be "marginal" suppliers—that is, newly-built thermal stations, or new hydro stations on sites not already developed (and hence high-cost, or environmentally-sensitive, or both). This element of "contestability" is expected to result in a long-run wholesale price for electricity at the marginal cost of new supply.

It is of some interest to relate our rent estimates above to the disputed issue of the value of Electricorp's assets. We have analysed at least $580 million of the $630 million operating surplus of the generating system for the 1985/86 year as differential rents (Table

1 and discussion) on the basis of the controlled price then ruling, and on the basis of the cost structure characteristic of pre-corporatisation NZED. It was shown that in 1985/86 average revenue was not much above average operating cost of thermal supply, which means that it was substantially below the long-run marginal cost of supply (that is, below the level at which it would be possible for a new generating station to break even, including covering its capital costs). A common estimate of the long-run marginal cost of new thermal generation in 1986 was around 8 cents/kWh, about double the short-run marginal cost at that time, taken to be the average unit operating cost of the thermal stations as a block, from Table 2. The following year Treasury estimated the long-run marginal cost of new supply as "in the range of 8-11 cents per unit ($1987)" (Treasury 1987, p.4).

This implies that in 1986, the "barrier to entry" provided by the gap between short-run and long-run marginal cost could have enabled a deregulated NZED to add 4 cents or more per kWh to its average revenue before being threatened by the entry of competing generating stations. If all output at the 1986 level continued to be purchased at the higher price, the resulting extra 'Salter rent' on the 22,000 GWh not sold to the Bluff smelter would have added $880 million to the $580 million-odd of actual differential rent, a total of nearly $1.5 billion. Allowing for subsequent inflation and possible cost savings under corporatisation, it seems safe to say that the *potential* operating surplus of the electricity system now operated by Electricorp should be above $1.5 billion annually, if the above estimates of marginal cost are correct.

At first sight, an asset capable of earning $1.5 billion annually should be worth well above the $8-10 billion which Treasury was asking on the taxpayers' behalf (until the negotiations were taken out of their hands by a group of Cabinet Ministers late in 1987), let alone the finally-agreed price of $6.3 billion. Such a low price could, however, make sense if "market-clearing" prices are expected to remain below the long-run marginal cost estimates just cited; or if Government intends to continue to use price control to prevent Electricorp extracting Salter rents from its customers in the short run. In the longer run such a price-control policy would not be sustainable, because as demand for electricity expands, the existing system will eventually be unable to satisfy demand, leading to a demand for new generating stations to be built. To warrant such construction, the average electricity price would have to equal the long-run marginal cost by the time excess demand appears—say, early in the next century. The doubling of the existing average price entailed in this adjustment, Treasury suggests, will need to take place some time over the next 12 or so years (Treasury 1987, p.4 ). The controlled price can reach its long-run level along any year-by-year "path" chosen by the government's regulators.

Electricorp, in their 1987 forecasts, discuss the future course of prices and show in a table and diagram (reproduced as Appendix I) the assumptions on which their main forecasts of electricity demand are based (Lermit and Cameron 1987, p.16). They have the existing (1987) bulk tariff of 5.4 cents/kWh prevailing until 1990/91, after which the wholesale price (in 1987 dollars) rises to 6.6 cents by 1995/96 and 8.9 cents by 2006/07. This last figure appears to be their present estimate of the unit cost of new generating capacity, and they comment (1987 p.22) that "the Corporation will be unlikely to carry out new developments while the price charged remains below the cost of expanding production".

A back-of-envelope calculation using these prices shows that if Electricorp were currently securing, say, $600 million of rent annually from generation of about 27,000 GwH at a wholesale price of 5.4 cents/kWh, then annual rents would rise to the full $1.5 billion by the year 2006/07, and the present-value at 10 percent of the stream of rents *even if no profit were secured on any increase in sales above 27,000 GWh* would be $9.5 billion. At the 9 percent discount rate favoured by Electricorp (Lermit and Cameron 1987 p.17) this would rise to $10.8 billion, while at the 13 percent discount rate used in some other parts of the government sector, the present value would drop to $6.7 billion. These figures recognisably overlap with the range in which bargaining between Treasury and Electricorp was proceeding in late 1987 before an impasse was reached. However, our back-of-envelope numbers seem to suggest that Treasury's asking price of around $8-10 billion, which Electricorp evidently rejected, could be considered to have been rather low, especially at the lower discount rates. [Electricorp is reported to be currently using a 7 percent discount rate.]

There seem to be two major reasons why Electricorp might be more pessimistic about its future profitability than our figures above would suggest. The first is that the figure of 8.9 cents/kWh for the unit cost of new supply may actually be rather above the price at which competing suppliers might enter the New Zealand electricity market. Several possible competitors might expect to undercut the 8.9 cents figure, possibly substantially, on the basis of low fuel costs. A natural-gas-burning electricity station built as a downstream diversification by Petrocorp, or the partners in the recent Kupe oil/gas strike, or Brierley Investments, or by the Auckland Electric Power Board in association with any of these, might conceivably push its unit costs down to the 6-7 cent range by shaving investment costs, using new improved technology, and using the new station as a means of flaring-off "surplus" gas. Similar downstream investment by Coalcorp might also undercut the Electricorp figure, if a decision were taken to exploit coal resources which had no other market. The price path assumed by the Electricorp forecasts, and the (probably similar) path underlying Treasury's calculations, may thus not be attainable.

Secondly, as Electricorp note at some length in their forecasts (Lermit and Cameron 1987, pp.22-25, 31-32), one major possible competitor for the local electricity market is energy conservation. Three recent studies (Boshier et al 1986; NZERDC 1987; Tolerton 1987) have drawn attention to the possibility that electricity-saving technology could be introduced at a rate sufficient to eliminate future growth in electricity consumption by the New Zealand economy. Tolerton estimates that 4.5 PJ/year of electricity could be saved by conservation measures which would have positive pay-off to the consumer at an average cost equivalent to 6 cents/kWh. In that case, existing generating capacity would suffice to meet future needs, and there would be "a corresponding decline in long-run marginal cost as the need for capital developments is reduced" (Lermit and Cameron 1987, p.24). This opens up the possibility of stagnant electricity demand with no real increase in the existing wholesale price, leaving a present value of the Electricorp operation of, say, $6 billion. Such inability to push up the electricity price to full long-run marginal cost in the face of consumer resistance and the availability of a competitive substitute (conservation) is the most likely reason for valuations of the electricity system lower than $10 billion.

To date, New Zealand households have shared (via lower-than-marginal-cost prices) in the differential rent resulting from their country's possession of high-yielding generation sites. In future, this dissipation of the rent will be replaced to some (as yet unknown) extent by a process of appropriating the rents as revenues or dividends to government. The rents, thus, are being reallocated to a new use: away from subsidising living standards directly, and towards relieving the burden on taxpayers of government debt. If, as a result, tax rates can be cut significantly because of increased earnings from electricity sales, this would provide countervailing relief via household disposable incomes; but the benefits of tax cuts are unlikely to accrue to the same groups that benefit most from the existing subsidy. In *principle*, however, the reallocation could be achieved without leaving anyone in New Zealand worse off—especially if some component of increased electricity charges can be "exported" (e.g. by loading it onto the consumers of Bluff aluminium or other electricity-intensive export commodities).

From a revenue point of view, thus, the best way to conceptualise the proposed sale of the system to Electricorp is to view Electricorp as taking over from the Government the servicing of some $6.3 billion of the existing national debt. The formal transfer of the assets is not necessary to accomplish this aim; all that is required is for the Government to lay claim to the rents from electricity generation under the heading of revenues available to be used to support government expenditure in general (in contrast to the past and present—until Clyde and Ohaaki are completed—when electricity rents have been earmarked for large-scale projects to build new power stations). Since Electricorp's existing interest payments on its loans from the government already contribute some $400 million to the government's debt-servicing capacity, the net budgetary gain should not be overstated.

From the point of view of the Royal Commission, the interest of this issue arises from the effect of electricity prices on household living standards. The possibility that (real) electricity prices could rise *on average* by about 100 percent some time in the next decade or so, coupled with the declared intention to introduce new pricing structures to eliminate the existing cross-subsidy in favour of domestic electricity users, would mean that one of the long-established universal benefits provided by government would be sharply reduced.

The best way for New Zealand to hold down electricity prices in the long run is to encourage energy conservation measures and thus avoid the future necessity of building more power stations. There is thus a strong pay-off to household living standards from successful implementation of conservation measures, and it could be appropriate for the Commission to make mention of this point in its report.

## 2 *CNG Retailing: a Case of Quasi-Rents*

A 1983 study of the CNG industry collected cost estimates for service stations selling CNG to motorists, and estimated their profitability (Ellis 1983, Chapter 7). The situation at that time was that CNG was a relatively new fuel and only a few stations in each area were equipped to sell it. Consequently:

> most stations still have a catchment area in which they have a weak monopoly. Stations in smaller centres, or where the entry of would-be competitors is restricted by limitations on the available gas supply, have a stronger monopoly.
>
> The consequence of this, together with exemption from price control, is that CNG stations have been able to set their prices at a level which provides them with a generous return on their investment, provided that they can obtain sufficient turnover to keep their equipment busy. The same price yields a much less generous return if the station is only supplying a light level of demand, such as that to be expected soon after opening (Ellis 1983 pp.180 & 182).

The cost of installing CNG equipment in an existing service station, taking account of government grants, was estimated as \$94,000 for a small station selling 670 cubic metres of gas a day, and \$166,000 for a large station selling 3,000 $m^3$ a day. The smaller station could be expanded to 1,000 $m^3$ a day at an extra cost of \$25,000 (with government grant); and the large station could be expanded to 4,300 $m^3$ a day at a cost to the owner of \$69,000 (Ellis 1983, pp.183-186).

Operating costs were estimated for these four representative types of operation: small, small expanded, large, and large expanded. Station operating costs and revenues are shown in Table 4 below:

Ellis estimated the selling price required for each type of station to break-even as an investment proposition (providing for a depreciation rate of 10 percent and a net profit before tax of 20 percent of original capital outlay). This permits estimation of the so-called "normal profit" required to warrant the installation of new CNG retailing equipment, and hence gives an estimate of the quasi-rents secured as a result of the ability of the limited number of operators in the industry to charge an average price of 42.2 cents per cubic metre. In the longer run, as Ellis points out (1983 p.196) competition from new entrants would be expected to drive the price down towards the normal-profit level. In the short run, early entrants to CNG retailing secured quasi-rents, at a rate that increased sharply

TABLE 4: CNG retailing in 1982 cents per cubic metre

| Type of station | Operating cost | Selling price | Break-even price | Actual | "Normal profit" | Quasi-rent |
|---|---|---|---|---|---|---|
| | | | | — Operating surplus: — | | |
| *Small* | 25.7 | 42.2 | 37.4 | 16.5 | 11.7 | 4.8 |
| *Small expanded* | 26.1 | 42.2 | 36.0 | 16.1 | 9.9 | 6.2 |
| *Large* | 26.3 | 42.2 | 30.9 | 15.9 | 4.6 | 11.3 |
| *Large expanded* | 26.4 | 42.2 | 30.5 | 15.8 | 4.1 | 11.7 |

*Source:* Ellis 1983, pp.193-195

with the size of the operation. It was presumably the existence of these quasi-rents that attracted one of the major oil companies (Caltex) into early promotion of CNG, thus stealing a march on its competitors.

The working of this long-run market adjustment mechanism was aborted in 1984 by the imposition of new standards for the on-line metering of CNG sold by retailers (Ministry of Energy 1984, p.56). These standards required the installation of pumps with high-technology electronic metering equipment, at a cost of around $25,000 apiece. At a stroke, the new standards radically reduced the incentives faced by new entrants to the CNG retailing sector, and cut the profits of those already in the industry. The quasi-rents, thus, rather than being squeezed out as the industry expanded to itsa competitive-equilibrium numbner of outlets, were transferred as extra revenues to the manufacturers of the new metering equipment.

## 3 *Petrol: The Marsden Point Refinery*

The expanded and upgraded refinery at Marsden Point was built on the basis of an undertaking by the New Zealand Government that the owners (the consortium of major oil companies serving the New Zealand market) would be permitted to recover a "reasonable" (around 15 percent) return on their capital investment by loading capital charges onto the local-market prices of oil products. The refinery's costs subsequently over-ran the original estimates by a large margin.

Oil company projections indicated that the type of expansion desired by the Government—a hydrocracker capable of processing a wide variety of types of crude oil—would not be profitable if undertaken in a competitive market context. That is, there were no perceived rents to be obtained from a free market. Only the government's willingness to guarantee the refinery partners a monopoly of the domestic market, and to permit them to exploit that monopoly by raising petrol and other oil-product prices, made the expansion worthwhile. The benefits to New Zealand, the government argued, would take the form of greater security of supply in the event of a new Middle East war or embargo; the higher prices for motorists were a fair price to pay for this security.

From the private companies' point of view, their favoured local-market position was only as secure as the Government's tenure of office. However, the new government in 1984-85 chose to assume the whole of the refinery-expansion debt, somewhat more than $5 billion. Subsequently, however, the Government has moved towards deregulation of the local market, which may mean that the refinery ceases to be a competitive supplier even with its debt servicing charges carried by excise tax rather than through price recovery.

Barr and Gaudin (1985) traced the historical course of the prices of premium gasoline and light crude oil, in real 1984 dollar terms, from 1965 to 1985. The real price of gasoline about 1973 before the first oil shock was 45¢ per litre. Following the first oil shock, the real price rose to 80¢, and apart from a dip in the late 1970s (reversed by the second oil shock of 1979-80) was still at this level in 1984. There then took place a sharp increase to 90¢, following the 1984 devaluation and Budget adjustments.

Tax as a component of the price, Barr and Gaudin showed, was lower after 1980 than in the preceding 30 years, and was not a factor in the mid-1980s rise in prices. (Tax has been around 22 cents/litre real over the past several decades). Having allowed for changes in crude oil prices and in taxes on petroleum products, they concluded that:

> The component of the price that has increased is the refinery and distribution margin . . . There have been very tight refinery processing margins overseas since 1981. In spite of this, the total New Zealand margin has increased from some 20 cents/litre prior to 1973, to approximately 30 cents/litre between 1982 and the present. The major reason for this 50 percent increase appears to be the previous government's decision that a large component of the Marsden Point refinery expansion would be loaded onto the gasoline price.
>
> This loading is presently 7.48 cents/litre on all petroleum fuels whether processed by the Refinery or imported directly. It is a cost-plus loading

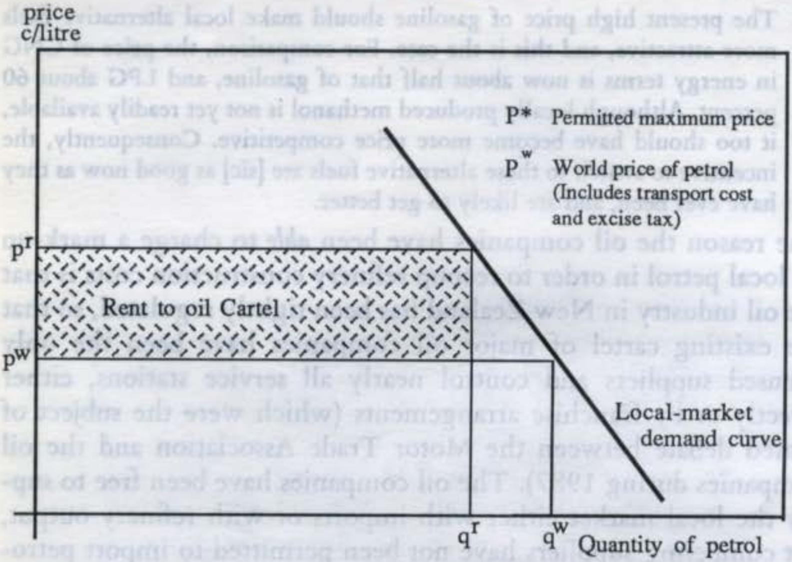
> that is expected to rise significantly in the near future, perhaps to more than 10 cents/litre.
>
> The present high price of gasoline should make local alternative fuels more attractive, and this is the case. For comparison, the price of CNG in energy terms is now about half that of gasoline, and LPG about 60 percent. Although locally produced methanol is not yet readily available, it too should have become more price competitive. Consequently, the incentive to switch to these alternative fuels are [sic] as good now as they have ever been, and are likely to get better.

The reason the oil companies have been *able* to charge a mark-up on local petrol in order to recoup refinery construction costs is that the oil industry in New Zealand has been tightly regulated, so that the existing cartel of major oil companies have been the only licensed suppliers and control nearly all service stations, either directly or by franchise arrangements (which were the subject of heated debate between the Motor Trade Association and the oil companies during 1987). The oil companies have been free to supply the local market either with imports or with refinery output, but competing suppliers have not been permitted to import petroleum products for resale. New Zealand consumers are therefore unable to purchase petrol at its import price, and must instead pay a loading on the price to support the refinery.

Figure 7 shows, in terms of simple economic theory, the way in which it was originally envisaged that the capital charges for the refinery expansion would be loaded onto the New Zealand petrol price. The price $p^w$ is the world price at the current exchange rate, marked up for normal wholesale and retail margins and New Zealand excise taxes. (That is, $p^w$ is the price petrol consumers would pay if there were a free market.) The price $p'$ is the permitted price charged by the oil companies. The higher price reduces local market demand from $q^w$ to $q'$, but given a low price elasticity of demand for petrol the smaller market yields substantially greater revenues to the cartel than would prevail in the free-market situation. The shaded rectangle shows the rents gained by the refinery partners as a result of their monopoly position in the local market. Obviously, de-regulation of the industry would open the way for companies not involved in the Refinery to bring in imported petrol and sell it at the lower price $p^w$, thus undercutting the Refinery cartel.

It was this vulnerability of the cartel to competition from imports in a de-regulated environment that probably underlay the government's 1986 decision to convert the "refinery levy" part of the

FIGURE 7: Price structure of premium petrol




local petrol price into a general excise tax, which is now to all intents and purposes indistinguishable from the other taxes on petrol, such as the National Roads Board tax, and the revenue from which goes into the Consolidated Fund, out of which the government has undertaken to pay the costs of servicing the debt resulting from the expansion. In terms of Figure 7, the effect of this change is to collect the shaded area as excise tax rather than allowing the companies to collect it directly as a mark-up. Because an excise tax is charged on all petrol (including any that may be imported by new competitors) the price of imported petrol is effectively pushed up to $p^r$, eliminating the possibility of the existing cartel's being undercut by new entrants to the petrol wholesaling industry. This, of course, amounts to a substantial degree of protection for the refinery via a mechanism of cross-subsidy: competing suppliers' petrol will carry a tax burden the revenue from which is then passed across to service the capital charges of their competitors.

The present price structure of premium petrol is shown in Table 5. It can be seen that of the total tax of *36.36 cents per litre*, nearly half (16 cents) originated as the cost of servicing refinery debt, but was consolidated into the other taxes in 1987. The implications of this consolidation are of some interest and importance. In the 1986 Budget, the government announced that it would take over from the New Zealand Refining Company the responsibility for servicing the company's debts, as part of moves to deregulate the oil industry. The government shortly thereafter borrowed in the vicinity of $5.3 billion overseas for the purpose of taking over the outstanding debt, and introduced a 16 cents-per-litre levy on all petrol sold in New Zealand. At that point, however, the procedures halted. The borrowed money has since been held abroad, while the Government is still paying over to the Refining Company the proceeds of the 16 cents levy, even though this has now been converted to a general excise tax paid initially into the Consolidated Fund.

Once the oil industry is deregulated, therefore, the government will remain responsible for maintaining servicing payments on the refinery debt, leaving the Refining Company carrying only a small residual risk in the event that passing crude through the tolling operation at Marsden Point proves less profitable for the major oil companies than shipping-in refined product from overseas. This decision is of marginal significance relative to the really big windfalls of the past. Any real profit on the Marsden Point refinery expansion was taken out of New Zealand in transfer payments for equipment and services during the first half of the decade, under the contractual agreements with government that loaded the cost of the resulting debt onto petrol consumers.

With the refinery levy now incorporated into the general excise taxes charged on all petrol sold (whether of local or overseas origin), the pricing structure required to sustain the refinery would render imported petrol competitive in the local market if it can be landed at less than *28 cents per litre CIF*. In fact, the import statistics for the 1986-87 June year show (Item 334.11.43) imports of 374 million litres at an average CIF valuation of *27.6 cents per litre,* and VFD valuation of 24.8 cents. This seems to indicate (if the import valuations are to be believed) that there are no large *current* rent flows accruing to the refinery, and that *with its capital costs met,* the refinery can more-or-less match import competition. Comparison with US retail prices shows them equivalent to roughly *40 cents/litre* at an exchange rate of 65 cents United States/NZ$1, which seems consistent with the above figures if allowance is made for markups and distribution costs.

An interesting question currently is whether the debt-servicing costs are actually as high as 16 cents per litre of petrol. World interest rates have fallen substantially—by at least a quarter to a

TABLE 5: Breakdown of the premium petrol price, March 1988

| | | Cents per litre |
|---|---|---|
| Retail price | | 92.0 |
| Retailers' margin, including GST | | (8.737) |
| Wholesale price including GST | | 3.263 |
| GST component of wholesale price | | (7.569) |
| Wholesale price net of GST | | 75.694 |
| Bulk sales fator (average effect) | | +0.450 |
| Average recovery to oil companies | | 76.144 |
| Oil companies' inland distribution and profit margin | | (11.600) |
| Total taxes other than GST: | | |
| *To Consolidated Fund:* | | |
| Former Refinery levy | 16.00 | |
| Other | 9.80 | |
| Total | 25.80 | |
| To National Roads Board | 9.90 | |
| Total Excise taxes | 35.70 | |
| Local Authorities Petroleum Tax | 0.99 | |
| Total taxes | | (36.36) |
| Available to meet landed cost of petrol at main ports | | 28.184 |

*Source:* Ministry of Energy

third—since the expansion finance was raised. The servicing costs on the debt could now be as low as *10-12 cents per litre,* leaving government with a useful supplement to its general revenues, and hence to its goal of reducing the budget deficit. This additional tax is currently being collected under cover of the claim that the full amount is required for debt servicing; but in future it provides the government with an obvious opportunity to reap political advantage from significant reductions in petrol prices, undertaken at its discretion.

For the longer run, an equally interesting question is whether it will be profitable to keep the refinery operating in a de-regulated environment. Even with its capital charges covered, the refinery is only just able to match the import prices of refined products. The next round of bargaining between the major oil companies and the government may well involve a threat from the companies that the refinery will close down (with obvious implications for unemployment in Whangarei) unless subsidies on operating costs are provided to supplement the government's assumption of capital charges. There are, in sum, few if any rents now arising from the refinery *per se.*

## *Conclusion*

This paper has taken a brief look at some theory relating to economic rent, and the application of such theory to three case studies in the energy area. The central feature of energy economics is the enormous size of the rents which from time to time are encountered, and the consequent ability of the energy sector to support some of the New Zealand economy's largest and most profitable concerns.

The importance of rent is not simply as a flow of current income (which in simple theory could be taxed away without altering *current* resource allocation). It has a central role as an incentive to warrant the very large-scale investments characteristic of energy production; and as the central issue in negotiations between energy enterprises and government—for example, over the asset value for Electricorp, or the terms of construction of the refinery expansion. In the Electricorp case, the parties have just announced an agreed valuation of $6.3 billion, which is very low relative to our calculations earlier in this paper, and must be presumed to incorporate a discount (about half-a-billion dollars) for the concealed subsidy to Comalco which will now have to be met by Electricorp, as well as reflecting pessimistic [low] price expectations and skilled bargaining by Electricorp management.

In the refinery case any rents were capitalised and taken out during construction, leaving a commercially-marginal operation, a heavy debt burden bequeathed to future taxpayers, and the likelihood of demands for further subsidies in the near future.

It is noteworthy that only in the case of quasi-rents, such as those identified in the CNG case study, can it be left to market forces to eliminate rents over time. In cases of differential rent (such as the electricity system) the rents exist in perpetuity, and only their distribution is open to be decided by the market or by other forces. In the past, Electricorp's rents have been partly dissipated to consumers via low prices, partly dissipated to the large dam-building labour force by means of over-investment in redundant generating capacity (especially Clyde), and partly appropriated by government. In future, the government's claim will be determined by tax laws and by the newly-agreed asset valuation and its associated "required rate of return", which will give the government a flow of dividend income from the Corporation. Because the valuation has turned out low, the Corporation is likely to retain control of a substantial part of its rent income and will therefore have large resources available to finance diversification of its interests (and to attract buyers if the operation is eventually privatised).

In cases of legally-protected monopoly rent, finally, two points are relevant. First, there are incentives for those protected by politically-sustained shelters to capitalise their advantages at an early stage. Second, rent persists only so long as the policy regime does not change. The 1984 change of government has brought a radical change in the policy regime under which the oil industry operates in New Zealand, and the move towards de-regulation has forced the Labour Government to confront several rather special problems arising from bilateral-monopoly bargaining during the "Think Big" era at the beginnning of the decade. The difficult conflict arises that one central objective of deregulation—cheaper petrol for New Zealand consumers—is inconsistent with the inherited arrangement to pay for the refinery expansion out of petrol prices. Only by shifting the debt burden from petrol consumers to taxpayers can the government clear the way for substantial reductions in petrol prices beyond relatively marginal opportunities for cut-price discounting by wholesalers and/or retailers.

# References

Barr, H. and Gaudin, A., 1985, *Automotive Fuels in New Zealand: Trends in Real Prices* (Wellington, DSIR Applied Maths Division).

Baumol, W.J. and Bradford, D.F., 1970, "Optimal Departures from Marginal Cost Pricing", *American Economic Review* June.

Bertram, I.G., 1978, "The Political Economy of Oil: Peru and New Zealand Compared", *Australia and New Zealand Journal of Sociology* Vol.14 No 3(Part 2), October.

Boshier, J.F., Allan, R.R., Ellis, M.J., Gallacher, J., and Phillips, P.H., 1986, *Four Futures: Energy Implications of Social and Economic Change* (NZERDC, Wellington).

Electricorp, 1987, *Electricity Pricing: an Invitation to Contribute* (Wellington).

Ellis, M.J., 1983, *A Cost-Benefit Assessment of Compressed Natural Gas* (M. Phil. thesis, University of Auckland.

Gordon, H.S., 1954, "The Economic Theory of a Common-Property Resource: the Fishery", *Journal of Political Economy*, April.

Lermit, R.J., 1986, *The Economics of a North and South Electricity Tariff Differential* (Wellington, NZED).

Lermit, R.J. and Cameron, L., 1987, *Electricity Sector Forecast 1987* (Wellington, Electricity Corporation of New Zealand Ltd).

Ministry of Energy, 1984, *Annual Report for the Year Ended March 31 1984*, Appendices to the Journals of the House of Representatives, D6 (Wellington, Government Printer).

New Zealand Electricity Division, *Annual Statistics in Relation to Electric Power Development and Operation in New Zealand* (Wellington, Government Printer).

New Zealand Energy Research and Development Committee, 1987, *Energy Management in the Domestic Sector* (Report for the Ministry of Energy, Wellington).

Parmenter, B.R. and Webb, L.R., 1974, "Prices Justification and Microeconomics", *Australian Economic Review* 1974:2, pp.55-60.

Salter, W.E.G., 1966, *Productivity and Technical Change* (Cambridge University Press).

Tolerton, D., 1987, "How Big is the Fifth Fuel Resource?" in International Energy Agency, Energy Demand Analysis Symposium, October 12-14 1987 (Paris, IEA).

Treasury, 1987, *Valuation of Electricity Generation and Transmission Assets* (Wellington, mimeo).