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Perspectives on Policy

Non-Linear Pricing Theory: The Case of Wholesale Electricity Pricing in New Zealand

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In order to establish a wholesale electricity market in New Zealand it has been necessary to determine appropriate pricing arrangements for wholesale electricity. In the early 1990s, a conflict arose between the efficiency requirement for new entrant generators to achieve their required rate of return (which implies a marginal-cost price on incremental supplies) and the equity effect on existing consumers of a substantial price increase to achieve linear marginal-cost pricing. This paper provides the theoretical underpinning for advocacy of so-called "progressive pricing" as a second-best way to reconcile these conflicting objectives, and attributes the eventual rejection of non-linear pricing to changes in key parameters.

1. Introduction

The deregulation of the New Zealand electricity industry since 1984 has been bedevilled by the issue of how wholesale electricity should be priced. From 1923 to 1987, grid electricity was generated by a government department whose prices were set to recover average costs, defined to include a contribution to new capital formation. Competing entry by independent commercial generators was blocked both by legislation and by the ability of the New Zealand Electricity Department (NZED) to cross-subsidise its marginal plant. The costs of generation and transmission were bundled into the bulk supply tariff.

Following corporatisation of the Electricity Corporation of New Zealand (ECNZ) in 1987 and the separation of the grid operator TransPower in 1993, electricity transmission and generation prices were unbundled and more commercial pricing procedures were introduced. The issue then arose of whether the unbundled price of generated energy was above or below the competitive price, i.e., the price at which new independent generators could earn normal profits

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while producing energy for distribution over the TransPower grid. Consensus opinion in the industry (supported by the absence of new entrants) was that ECNZ's wholesale price was below the average incremental cost of electricity, and hence was a barrier to entry.

To create a competitive generation sector, therefore, a price increase was required. From 1987 to the early 1990s, ECNZ management and the NZ Treasury lobbied hard to move the wholesale electricity price up to long-run marginal cost.[1] Treasury in 1987 anticipated that this would mean between 8 and 11 cents per kWh, an increase of 300-400% on the then-prevailing price.[2]

Such a price increase would bring large windfall profits to ECNZ, and hence to the Government as its owner,[3] at the expense of electricity consumers. Opposition was vocal and well-organised, leading to a Parliamentary Select Committee inquiry into electricity pricing in 1991-1992. The report of that inquiry (Commerce and Marketing Select Committee, 1992) recommended non-linear pricing, to raise the price paid for incremental supplies of electricity while protecting consumers from a general price increase.

This paper discusses some theoretical issues raised by this debate, focusing on the proposals for non-linear pricing of wholesale electricity put forward by the Commerce and Marketing Select Committee (1992), Bertram, Dempster, Gale and Terry (1992), and WEMS (1992, Vol. 5A, Appendix B). It is shown that the so-called "progressive pricing" of electricity is theoretically defensible, but that the attractiveness of such a pricing arrangement depends heavily on the position and slope of the expected average incremental cost schedule, and on the weight which policymakers attach to the interests of consumers. Changes in both of these help to account for the New Zealand Government's 1995 decision in favour of linear marginal-cost pricing of wholesale electricity supplied to purchasers other than Comalco.[4]

[1] Electricity Corporation of New Zealand (1987, Appendix). For the purposes of this paper no distinction is drawn between long-run marginal cost and its "lumpy" analog, average increment cost.

[2] New Zealand Treasury (1987).

[3] The implication was that the book value of ECNZ's generation assets had been understated at the time of their transfer to the new Corporation, relative to the value which those assets would have had in a completely unregulated competitive wholesale market.

[4] Comalco, an aluminium-smelting enterprise, signed long-term contracts with NZED for low-priced electricity supply to its Bluff smelter in 1963 and 1981. The contracts were extended by ECNZ in 1993-1994, to run until after 2020. The present author has been critical of the Comalco contracts because of their discriminatory character and the accompanying history of capture of the policy process by a large multinational. Those criticisms, however, are directed at misuse of the multipart pricing instrument, not at the instrument itself. Given the initial political decision to transfer profits from NZED to Comalco's shareholders, the chosen contractual instrument was arguably the most efficient means.

2. Non-Linear Pricing and Income Distribution

2.1 Introduction

A standard result in price theory is that a first-best welfare optimum is achieved when a uniform market-clearing price can be charged which is equal to marginal cost, but, if this is not attainable, then there will exist non-linear price schedules that are Pareto superior to any linear price that is not a marginal cost price (Willig, 1978; Phlips, 1983, pp. 172-174; Tirole, 1988, p. 146). The literature built around this insight has generally been concerned with the situation where a natural monopoly cannot charge a marginal-cost price because of a profit constraint imposed by its owners, namely that pure profit must be non-negative. The problem is that a linear average-cost price (the lowest price consistent with the constraint) then lies above marginal cost, with consequent under-allocation of resources to the activity concerned. Non-linear pricing arrangements are invoked as a means of exercising the firm's monopoly power over consumers to extract part of their consumer surplus, in order to raise the monopolist's revenues and hence profit. Familiar examples of such discriminated prices are multi-part tariffs (Coase, 1946) and Ramsey prices (Baumol and Bradford, 1970).

The classic justification for non-linear pricing is thus the reconciliation of $P = MC$ at the margin with an income distribution goal - specifically, distribution between the firm and its customers. The standard textbook exposition addresses the situation where income is to be transferred from customers to the firm by the most efficient means possible. The argument normally starts from, or takes for granted, the assumption that the required transfer of resources is better accomplished directly by the price mechanism than via a tax-transfer organised by the government. [If government intermediation is regarded as the most efficient means of accomplishing the required transfer, then the case for non-linear pricing evaporates and the optimal solution is Hotelling's (1938) proposal that the government should subsidise the natural monopolist out of general revenues, and regulate the price of the subsidised good to equal marginal cost.]

The familiar arguments, one might suppose, should work equally well for the case where satisfying the income constraint requires an income transfer from the monopolist to its customers, for example, a situation where an increasing-cost monopolist is required to divest itself of excess profits.[5] In this case, pure profits (rents or producer surplus) could be dissipated to customers by a so-called "inverted block tariff" or its equivalent, as the alternative to a tax-transfer arrangement under which the monopolist is taxed and the revenues are used to fund government transfer payments to the population of consumers.

[5] The sub-additivity conditions for existence of a natural monopoly can be consistent with increasing costs; see Sharkey (1982). ECNZ's generation activities, however, are not a natural monopoly but a legal monopoly based on consolidated State ownership of prime hydro generation sites.

The mainstream literature devotes relatively little attention to this issue. Most writers evidently take it for granted that there is no symmetric counterpart to the natural monopolist's profit constraint, and hence do not address the mechanisms by which transfers from monopolist to customers might be accomplished. Recent surveys of non-linear pricing such as Tirole (1988, Chapter 3) and Norman (1992) deal only with non-linear prices which extract consumer surplus for the benefit of monopolists. Wilson (1992, p. 5, Figure 1.1 and p. 141) recognises in passing the existence of an increasing-block tariff schedule which he designates a "three-part tariff", but offers no analysis of such tariffs and only one example (lifeline rates).[6]

Nevertheless, several of the seminal papers on price discrimination do note the possibility of transfers from the monopolist to its customers. Baumol and Bradford (1970, p. 265) set up their general problem in terms which refer to undesired surpluses along with undesired deficits:

> We are ... faced with a problem in the area of the second best. Resource allocation is to be optimal under the constraint that governmental revenues suffice to make up for the deficits (surpluses) of the individual firms that constitute the economy.

And they add, in a footnote (p. 265), the comment that

> Presumably, as a practical matter, there is an asymmetry between the problems posed by surpluses and those resulting from deficits. The real difficulty arises when we try to collect resources to cover the deficits without distorting consumers' and producers' choices. Since it is not possible in practice to levy lump sum taxes whose magnitude is independent of the decisions of those who pay them, we are forced to consider second-best solutions to the tax problem. A surplus can presumably be distributed more easily in a "lump sum" manner. One can, for example, distribute shares in future surpluses to all members of the economy on the basis of their incomes at some point in the past, or one can simply divide them equally among all individuals.

Because their analysis was directed to the deficit case, Baumol and Bradford did not pursue further the nature of the instrument by which "shares in future surpluses" might be distributed to all members of the economy. The spirit of their discussion would seem to indicate that they had in mind an annual tax levy on excess profits, redistributed as a negative poll tax; but the expression "distribute

[6] He does note (p. 141) that "concavity is violated in several popular tariff designs", and describes the three-part variant as "especially common".

shares in *future* surpluses" hints that some contractual arrangement of the sort discussed later in this paper may have crossed their minds also.

Willig (1978), in a paper showing the Pareto superiority of non-linear prices over linear pricing under second-best conditions (i.e., conditions where a linear marginal-cost price schedule is not feasible), devoted the largest section in his conclusion to the case of "socially unacceptable" profits, arguing that a non-linear price schedule offered an efficient means of redistributing such surpluses. This emphasis in Willig's conclusion is intriguing, given the fact that the main body of his paper is focussed on the case where average-cost price exceeds the marginal cost (so that the pricing problem is to make up deficits rather than distribute surpluses). The relevant paragraph reads (Willig, 1978, p. 68):

> Of course, a uniform price equal to marginal cost is Pareto efficient from a partial equilibrium point of view. Yet there are several cases in which such a price may be viewed as undesirable for a public utility service. First, marginal cost pricing might induce a level of production at which there are locally decreasing returns to scale and a positive level of vendor profit that is viewed as socially unacceptable. ... In [this case] ... the establishment of a uniform price below marginal cost may be viewed as an effective way to redistribute vendor profits to consumers. However, the analysis of Section 5 [of the Willig paper] shows that there is a modification of such a price that improves the well-being of all consumers and increases vendor profit.

The "modification" referred to must clearly (in the context of the Willig paper) be an inverted two-block tariff of the sort outlined below. The apparent contradiction of "increasing vendor profit" by means of a pricing schedule, the ostensible purpose of which is to reduce profits to an acceptable level by redistributing them to consumers, is not resolved by Willig.

2.2 The Standard Model

At the outset it is worth reproducing the standard textbook story showing the optimality of a two-block tariff for a homogeneous commodity produced under conditions of decreasing cost by a natural monopolist subject to a minimum profit constraint. The point of doing this is to set the stage for discussion of the obverse case: a two-part tariff applied to an increasing-cost monopolist in order to satisfy a maximum profit constraint.

Figure 1, adapted from Willig (1978, p. 64) shows the standard decreasing-average-cost case where the monopoly utility sells quantity q_0 at the uniform average-cost price p_0, earning zero pure profit. The optimal quantity in the absence of a profit constraint would be q_1 corresponding to point k at the intersection of *MC* with *DD*, i.e., where marginal cost equals marginal willingness to pay. The deadweight loss triangle is ajk. Now suppose that a two-block tariff is introduced by means of which q_0 continues to be sold at p_0 but marginal consumption in excess of q_0 is sold at the lower price p_1 corresponding to marginal cost at q_1.[7] The deadweight loss is then eliminated, with abk appropriated as additional consumer surplus and bjk appropriated as additional profit. The move from a linear to a non-linear pricing schedule thus is a Pareto improvement which leaves small consumers unaffected but benefits large consumers and the producer. If the intramarginal price is now adjusted downward to restore the monopolist to zero pure profit, then all consumers gain while the monopolist is left no worse off.

Figure 1. Decreasing-Cost Monopolist

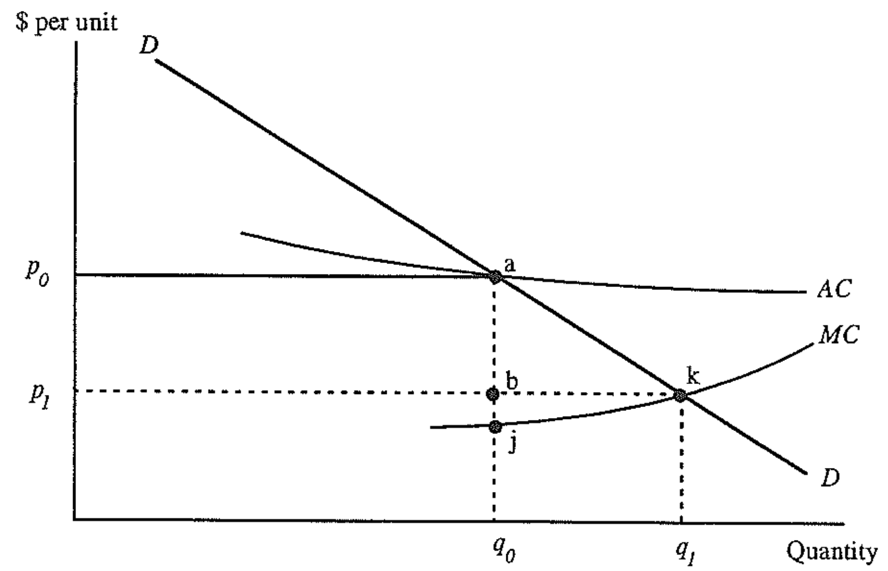
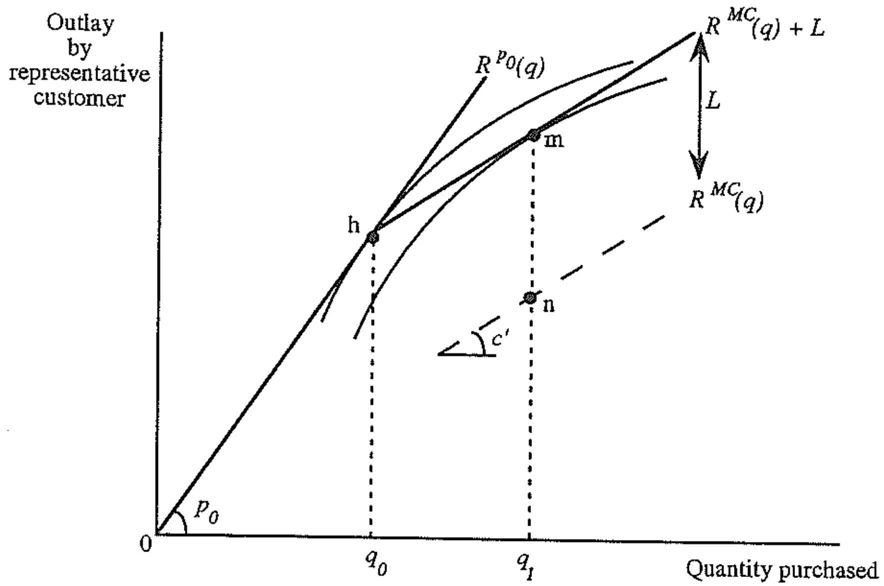


Figure 2, based on Willig (1978), shows the outlay schedules corresponding to these alternative pricing regimes. Here the slope of the line $R^{p_0}(q)$ shows the lowest uniform price consistent with meeting the profit constraint, and point h shows the customer's chosen quantity, q_0, at this price. The line $R^{MC}(q)$ is a uniform marginal cost outlay schedule constructed as a ray from the origin with

[7] Customers must be unable to arbitrage between the two blocks. The standard way of ensuring this is to specify the tariff as a discount for volume so that only the largest customers can secure the lower marginal price.

slope equal to marginal cost, and the parallel line $R^{MC}(q) + L$ traces outlays by the customer above quantity q_0 if a marginal-cost price is charged on all units above that quantity, ensuring that the monopolist meets its profit constraint at all points along $R^{MC}(q) + L$. A larger quantity q_1 (point m) is therefore sold, with the customer on a higher indifference curve and the monopolist's profit at the required level.

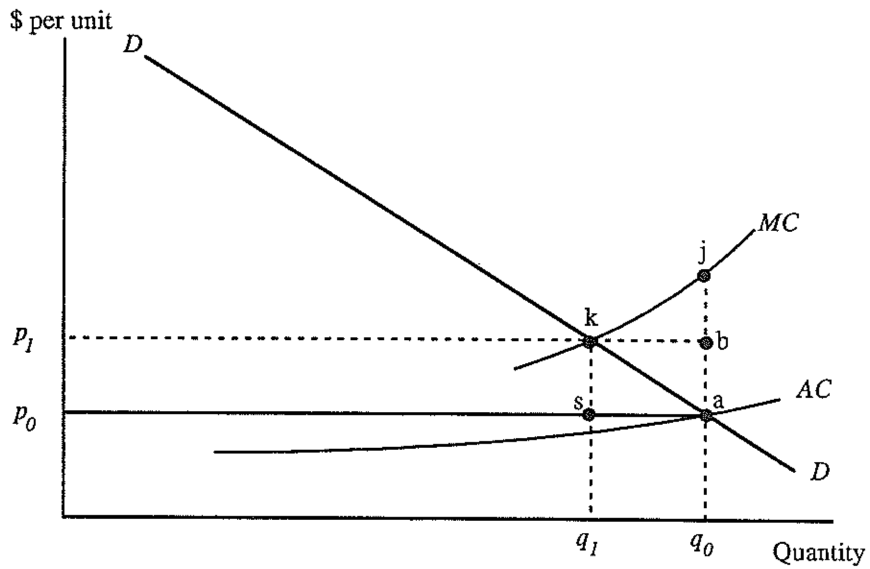
Figure 2. Outlay Schedules for Natural Monopoly



An important detail to which we shall return is that the Willig analysis is based on partial-equilibrium assumptions including the absence of income effects. In Figure 1 this means that the demand curve for the commodity does not shift when the change from a linear to a non-linear price schedule takes place. In Figure 2 it means that the output with a marginal-cost price will be q_1 regardless of the size of the implicit levy, L, embodied in the two-block tariff. With commodities such as electricity (which accounts for around 5% of household expenditure in New Zealand) this *ceteris paribus* assumption clearly cannot be left unchallenged.

The partial-equilibrium implications of a two-block tariff designed to distribute excess profits to customers can now be shown by simply reversing the relationship between the linear price and marginal cost in Figures 1 and 2. We take a situation in which the monopolist has locally increasing marginal cost and would earn excessive profits if a linear marginal-cost price were charged. The uniform (average-cost) price p_0 which satisfies the profit constraint is below marginal cost, resulting in demand q_0 above the optimum output q_1, and a deadweight loss of ajk in Figure 3 if this level of demand is met by the monopolist.

Figure 3. Increasing Cost Monopolist



Clearly, supplying output at this level is not profit-maximising behaviour, and one has to appeal to some other objective of the monopolist or constraint on it. In the case of ECNZ in New Zealand, the motivation clearly is a combination of political pressure and engineering pride, both of which impose strong sanctions against rationing demand by non-price means, while a political constraint has also been imposed on the wholesale electricity price.

A two-block tariff can be imposed which charges price p_0 up to quantity q_1 but the higher marginal-cost price p_1 on all units sold above this. The price schedule then runs $p_0$skb in Figure 3. The result would be to locate customers at q_1. The monopolist's profit then increases by ajks while consumers suffer the loss of consumer surplus aks, leaving the monopolist able to compensate consumers fully for the change and still emerge with the entire avoided deadweight loss as extra profit.

It follows from this that there must exist a number of possible increasing two-block tariffs which would leave the monopolist's profit unchanged (thus meeting

the constraint) while charging a marginal-cost price on the final units consumed and lowering the price on inframarginal consumption below p_0, thus ensuring that consumers are better-off following the change to a non-linear tariff. This is the arrangement often described as "progressive pricing".

Figure 4. Outlay Schedules for Increasing-Cost Monopolist

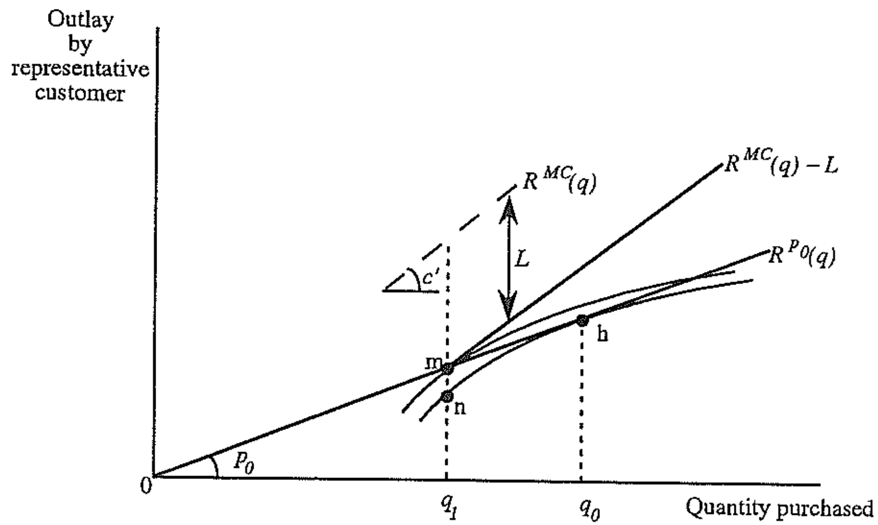


Figure 4 shows the outlay schedules for the progressive-pricing (inverted two-block) schedule derived in Figure 3. Introduction of the non-linear tariff shifts consumers from h back to m and so reduces their welfare; but if the monopolist's additional profits are now transferred to consumers by reduction of the inframarginal price, this has the effect of rotating downwards the $R^{p_0}(q)$ segment of the non-linear outlay schedule in Figure 4. The "corner" of the outlay schedule can then be moved down to touch the original indifference curve at n, leaving consumers fully compensated while reducing quantity demanded and increasing the monopolist's profit.[8] Further reductions in the inframarginal price can hold quantity at q_1 while bringing the monopolist's profit down to any desired level.

A feature of this result is that progressive pricing does not involve the regressive income-distribution implications of the "normal" two-block tariff (cf. Willig, 1978, pp. 61-64; Phlips, 1983, pp. 171-174). If instead of the

[8] It will be noted that this result depends on some assumptions about the shape of the utility function in Figure 4, but the required restrictions are trivial in this context.

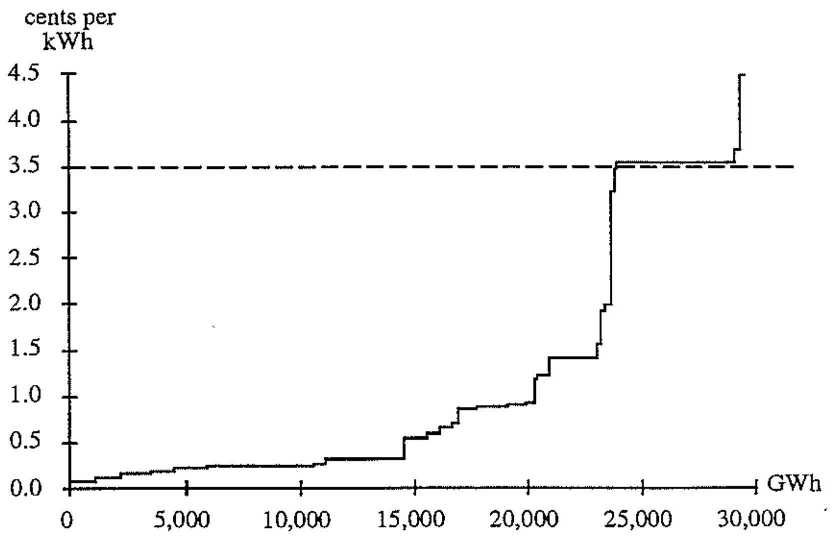
representative consumer we think of a spectrum of consumers from "small" ("poor") to "large" ("rich") the inverted tariff has progressive overtones with respect to income distribution (hence the term progressive pricing). Whereas the standard two-block tariff can be treated as a discount for large volume, the inverted two-block tariff offers, in effect, discounts for small volume. Because the detail of the tariff can be designed to benefit all classes of consumers, large as well as small, relative to the average-cost linear tariff, there is no need to offer a choice of two tariffs to ensure Pareto dominance, as Willig (1978) had to propose in order to ensure superiority of his standard two-block schedule.

3. Application to the New Zealand Electricity Industry

3.1 The Dominant Generator's Cost Curve

Figure 5 shows the estimated short-run marginal cost curve for ECNZ in the early 1990s. The curve is constructed by ranking generating plant in merit order of operating costs, so that the area under the curve up to the output of around 30,000 GWh per year shows the total operating costs of the Corporation. At that time, gross generated electricity was selling for 3.5 cents per kWh and the incremental cost of electricity from new stations was estimated at 6 cents per kWh. More recent figures show an estimated incremental cost of 5 cents per kWh rising to 7 cents as cheap generating opportunities are taken up (Officials' Committee on Energy Policy, 1995, p. 2).

Figure 5. Short-Run Marginal Cost Curve of Generation for ECNZ, 1991



The area above the short-run marginal cost curve and below the wholesale price is the gross surplus secured by ECNZ from its generation activities. The effect of raising the price across the entire market to the long-run marginal cost of, say, 6 cents per kWh would be to increase very substantially the surpluses obtained from sunk-cost assets, especially the hydro stations which have long lives and low unit running costs. On 30,000 GWh of existing generation, each cent added to the wholesale price of electricity would add $300 million to ECNZ's annual revenue flow, in effect a net addition to profit which should capitalise into roughly a $3 billion increase in the value of the assets.

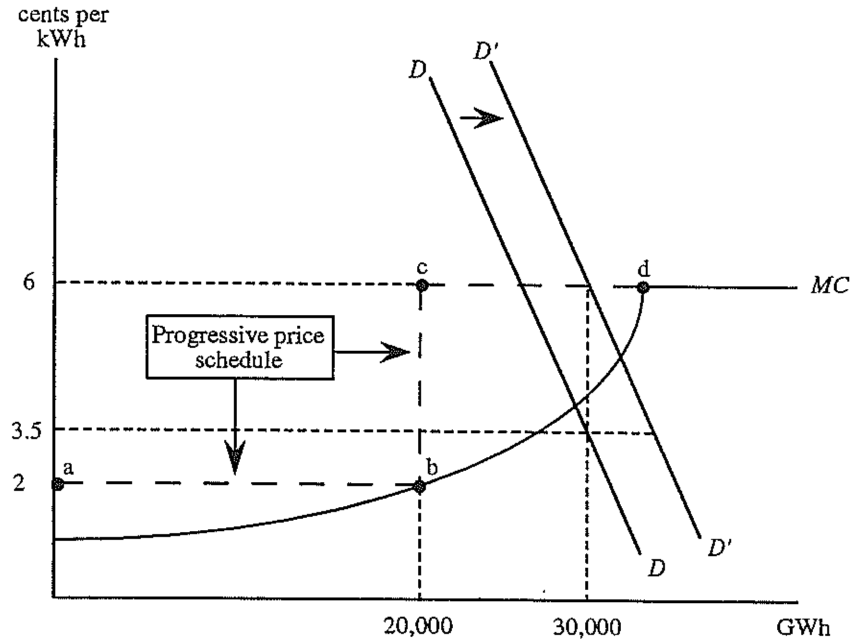
This prospective windfall gain on assets whose costs were sunk was the stumbling block to restructuring in the early 1990s. As Bertram, Dempster, Gale and Terry (1992, pp. 9-10) argued,

> It was evident in late 1991 that rapid progress towards competitive generation ... had stalled. The Task Force [Electricity Task Force, 1989] had not examined the wider macroeconomic and distributional implications of moving directly to a competitive generation market, and had not investigated alternative wholesale pricing structures which could address those effects. As a result, the reform process had proceeded on the implicit assumption that competitive generation requires consumers to meet a high uniform average price for electricity, determined ultimately by the cost of new generation. ...
> The result is that a political consensus cannot be constructed in support of the reforms, because there appear to be no clear benefits to consumers...
> [T]he restructuring process has lacked an implementation scheme which would deliver to consumers clear benefits from the establishment of a competitive market...

3.2 A Progressive Non-linear Price Schedule

Figure 6 shows schematically the two-block progressive-pricing proposal developed by the Hydro New Zealand project in 1992. An inelastic (derived) demand curve for wholesale electricity intersects the then-prevailing average price of 3.5 cents per kWh at gross output of roughly 30,000 GWh, yielding ECNZ revenue of just over $1,000 million. A non-linear price schedule (the heavy dashed line) is then introduced which gives the same total revenue but faces consumers with a marginal price of 6 cents per kWh, at that time the best estimate of long-run marginal cost. The schedule suggested in Bertram, Dempster, Gale and Terry (1992) was 2 cents per kWh on the first 20,000 GWh sold and 6 cents per kWh on the remainder, giving total revenue of $1,000 million provided that sales volume is not greatly reduced by the 70% wholesale price increase at the margin.[9] The rationale for putting these numbers into the original proposal was to achieve a Pareto improvement, leaving consumers no worse off in terms of the purchasing power of their incomes as the wholesale market moved into a competitively efficient price range at the margin.

Figure 6. 1992 "Hydro New Zealand" Progressive Price Proposal



3.3 The Use of Contracts to Underpin a Progressive Price

The obvious problem with any increasing-block tariff is to make it work in practice. As Wilson's (1992, p. 141) above-mentioned reference to "lifeline tariffs" indicates, the idea of increasing-block pricing of electricity has generally been associated with direct regulatory intervention in the pricing decisions of retail utilities. Progressive retail tariffs are charged by several US and Japanese utilities, but these tariffs have no basis in the cost structure of electricity

[9] In terms of the price facing actual consumers, whose demand determines sales volume, an addditional 2.5 cents on the marginal wholesale price involved only about a one-third retail price increase. With short-run demand elasticity less than −0.5 this would imply a fall in demand quantity of less than 15%, probably less than 4,000 GWh. By phasing-in the non-linear price, the Hydro New Zealand proposal envisaged restraining sales volume in the face of rising demand (shown by the shift of the demand curve from *DD* to *D′D′* in Figure 6).

generation for those markets,[10] being aimed rather to manipulate demand (inducing additional conservation effort and thus avoiding some investment in new generation plant, while providing effective transfers to small consumers). In evaluating the progressive-pricing option, many New Zealand industry analysts took for granted the equation of progressive pricing with permanent regulatory intervention. The reason is straightforward: profit-maximisation by a monopolist generator in a deregulated market would not lead to a progressive price schedule.

Other things equal, an unregulated increasing-cost multi-plant monopolist would seek to capture all possible rents on low-operating-cost plant by limit-pricing marginal output and applying this price back across all output. Such behaviour would obviously violate a maximum-profit constraint if one exists. Suppose now that the government were to adopt the position of seeking to modify the monopolist's behaviour in such a way as to prevent it from extracting these rents from consumers, without resorting to outright regulation. In ECNZ's case the Government has the substantial advantage of being the sole shareholder in the monopoly. How, then, might the government proceed?

One proposed solution was vesting contracts. When in 1991 the extent of political opposition to full-marginal-cost pricing of electricity became fully apparent, consultants to ECNZ proposed that the Corporation should defuse this opposition by issuing long-term contracts to selected large customers. These contracts would have locked-in low forward prices for specified quantities of electricity sold to those customers over a period of years. The vesting contracts idea was subsequently taken up by the Wholesale Electricity Market Study (WEMS, 1992, Vol. 5A, Appendix B), and by ECNZ. It was described as follows by ECNZ Chief Executive David Frow in Electricity Corporation of New Zealand (1994, p. 12):

> In late 1994, ECNZ will make an offer of long-term energy contracts to wholesale customers. The contracts will be for different quantities and durations, with customers able to choose their own quantity profile over time. The quantity offered in these initial long term contracts will be 100% of existing demand through the first three years, reducing progressively to 65% for contracts up to 12 years in duration. The pricing of these contracts will be advantageous relative to likely new entry prices, and it is expected that they will underpin the transition to a more competitive

[10] Electricité de France in the 1950s, as Boiteux, Brondel, Duquesne de la Ville, Morel and Richard (1958) noted at the time, charged a linear bundled price for electricity which implicitly combined an orthodox multipart tariff for transmission and a progressive price for generation (which at that time had an increasing-cost profile, with a core of hydroelectric stations and the margin occupied by coal, and later nuclear, stations). Since then the French generation cost curve has become a flat plateau at the cost of nuclear power.

wholesale electricity market by allowing prices to move very gradually towards market entry prices.

Forward vesting contracts of this kind are effectively financial assets whose secondary market value will be related directly to any expected difference between the contract price and the market price, and also to the term of the contract (i.e., the duration of the contractual discount). In offering these forward contracts to its wholesale customers, ECNZ was edging towards creating an instrument with a family resemblance to the Baumol-Bradford proposal to "distribute shares in future surpluses to all members of the economy on the basis of their incomes at some point in the past, or ... simply divide them equally among all individuals". Rather than income or citizenship, however, the criterion proposed by ECNZ was the size (hence market power) of customers.

An alternative approach, more in the spirit of the Baumol-Bradford suggestion and less discriminatory against small consumers, was articulated in the Hydro New Zealand scheme (Bertram, Dempster, Gale and Terry, 1992; Bertram and Terry, 1994). The scheme can be summarised as follows.

As owner of ECNZ, the Government would amend ECNZ's Statement of Corporate Intent to include a self-imposed limit on the Corporation's profit objective.[11] A long-term option contract would then be entered into with an independent trust, under which the trust could in any year call on ECNZ to issue to it forward hedging contracts on a fixed block of electricity generated by ECNZ stations. The benefits of these contracts would, in effect, be period-by-period rebates equal to the difference between the spot price at which electricity could be purchased from the proposed wholesale pool and the contract price. Those benefits would be distributed as vouchers to all wholesale purchasers of electricity, on the basis of their five-year average historic purchases, with an attached obligation on all of those buyers who are themselves electricity retailers to pass the benefits through as matching rebates to their retail customers on the same basis. Retailers whose disclosed pricing behaviour failed to reflect the pass-through of these rebates in some form to customers would forfeit the right to vouchers in the following year and so would be at a competitive disadvantage.

At first sight, these arrangements appear cumbersome, which led some commentators to claim that the Hydro New Zealand arrangement would be administratively complex and costly to operate. These concerns are not to be lightly dismissed, but in fact the suggested institutional structure was quite streamlined in comparison to some of the other mechanisms which have been envisaged to make so-called "light-handed regulation" operational in New Zealand utility industries, and they had the great advantage of meeting directly

[11] The need for such a self-imposed constraint follows from the initial assumption that a regulatory cap on profits is to be avoided. The State-Owned Enterprises Act 1986 makes no provision for self-regulation which prejudices commercial profitability.

the main problems arising with alternative proposals for wholesale electricity pricing:

- The mechanism provided effectively for a profit transfer from ECNZ into the hands of electricity consumers, including the smallest customers of retail utilities.
- The contract would be structured to prevent any party from capitalising out the benefits of the contract as a whole. Secondary market trading of contract rights would be unrestricted, but those rights (vouchers) would be in the form of forward hedges for the year of issue only. To qualify for a new allocation in the following year, each wholesale buyer would have to maintain its purchase history and demonstrate pass-through of benefits.
- Basing the voucher allocation on rolling-average historic consumption was a reasonably effective means of preventing customers from arbitraging between the two blocks in the long run. The cost of this would have been some muting of the long-run marginal-cost price signal, given that each customer's long-run planned purchases would comprise a bundle of high-priced and discounted electricity.
- Effectively all the serious transaction costs would have been incurred up-front in the drafting of the contract and trust deed. Once up and running, the entire scheme would be very low-cost.

The small print of the proposal is set out elsewhere (Bertram, Dempster, Gale and Terry, 1992; Bertram and Terry, 1994). The lesson from the exercise is that a contract mechanism can be devised which transforms revenues foregone by a monopolist generator into rebate benefits for retail customers, via a progressive-price schedule for both wholesale and retail electricity. Feasibility is not, therefore, an issue. There remains, however, the issue of whether non-linear pricing is a better way of compensating consumers than the original Hotelling (1938) proposal for a system of lump-sum taxes and transfers administered by the government.

4. The Tax-Transfer Alternative

4.1 The Distortion to Long-Run Price Signalling under Progressive Pricing

As soon as the progressive-pricing concept surfaced in New Zealand debates in 1991, it began to attract criticism on the grounds that electricity purchasers would face the full incremental-cost price in the short run but not in the long run. In the long run, the price that is relevant for new investment decisions is the discounted value of the total outlays on electricity over the life of the project. Any non-linear price schedule, by definition, puts a wedge between the average and the marginal price, and must therefore give a distorted signal for resource allocation in the long run *if the marginal price is set equal to full incremental cost*, as was proposed in the Hydro New Zealand scheme.[12]

The literature on price discrimination (exemplified by Figures 1 to 4 in the first part of this paper) is usually confined to short-run partial equilibrium, and seldom explores the long-run.[13] The literature on electricity pricing, however, includes much discussion of the choice between long-run and short-run marginal cost as the correct basis for setting efficient linear price schedules when capacity must be added in lumps (see, e.g., Della Valle, 1988; Park, 1989). This literature generally concludes that, in the long run, the two are equivalent so long as the average incremental cost of output from successive "lumps" is constant, but seldom addresses the question of how to deal with any undesired effects on income distribution when successive lumps come at rising average increment cost.[14]

The original Hydro New Zealand study estimated, on a back-of-the-envelope basis, that with wholesale electricity sold in blocks of 20,000 GWh at 2 cents per kWh and 10,000 GWh at 6 cents per kWh, a new load entering the economy at a 10% discount rate would face a long-run average outlay of 4.6 cents per kWh compared to the long-run marginal cost of new generation of 6 cents - a downward distortion of about 20% in the energy price of generated electricity, which translates to approximately a 10% distortion in the delivered price.[15] This distortion to the long-run energy price of electricity was largely offset by the opposite distortion in delivered electricity prices attributable to fixed lines charges in transmission and distribution (Bertram, Dempster, Gale and Terry, 1992, pp. 77-80). The net effect of the two distortions varied in sign depending on which customer class was considered; customers purchasing direct from the grid were estimated to face a long-run average price below marginal cost, while retail customers faced a price above marginal cost (Bertram, Dempster, Gale and Terry, 1992, p. 79, Table 8.5). The two distortions become apparent only when the delivered price of electricity is unbundled between generation and transmission, and the argument made by Bertram, Dempster, Gale and Terry (1992) was that if a two-part tariff was to be used to boost the profits of natural-monopoly transmission operators, a progressive-price arrangement for electrical energy could enable the required income transfer to be made from generation profits to transmission profits, rather than from electricity consumers to transmission profits. (Such transfers had, after all, historically been part of the bundled-pricing procedures of NZED).

This distortion in long-run price signals resulting from a contract-based progressive price for electricity is the main cost of adopting non-linear pricing. In any comparison with a first-best marginal-cost, linear price (the relevant comparison if the income constraint which motivates the quest for a second-best solution does not in fact bind) the progressive price model must emerge the loser on strict allocative grounds.

If, however, an income constraint rules out the linear first-best price, then the relevant comparison is a second-best one, between the non-linear-pricing solution and competing alternatives such as capped linear pricing or use of a separate policy instrument (lump-sum transfers) to satisfy the income constraint.

4.2 New Zealand Modelling of Alternative Price Regimes

An attempt to implement such price-regime comparisons was carried out by BERL late in 1994 for the Officials' Committee on Energy Policy, and involved use of the ESSAM variant of the JULIANNE computable general-equilibrium (CGE) model of the New Zealand economy. BERL were asked to compare three scenarios: marginal-cost pricing, average-cost pricing, and progressive pricing. The modelling technique was to project the economy out to 2010 under each electricity-pricing option, and then to compare the results from the three scenarios in terms of the level of GDP and the volume of electricity demanded in each scenario. Since the model is neoclassical, and since no income constraint on marginal-cost pricing was factored in, the results are as would be expected: "Marginal cost pricing leads to a more efficient allocation of resources than either average cost or progressive pricing" (Officials' Committee on Energy Policy, 1995, p. 4), and progressive pricing out-performs average-cost pricing.

The results of the three model runs are described in Officials' Committee on Energy Policy (1995, pp. 2-3) and summarised by the diagram reproduced as Figure 7 (ibid., Annex 1). The diagram shows, along the horizontal axis, the amount of additional generating capacity required to be built by 2010 and, up the vertical axis, the incremental cost of additional supply. An estimated demand curve at 2010 for each of the three scenarios is drawn, and each scenario is then costed on the basis of its requirement for additional capacity and the corresponding incremental cost.

Marginal cost pricing was estimated to lead to a need for around 7,600 GWh p.a. of additional capacity, pushing incremental cost to around 6 cents per kWh by 2010. Progressive pricing would require about 9,700 GWh p.a. of additional capacity pushing incremental cost to about 6.8 cents per kWh. Average-cost pricing would create a far greater expansion of demand, requiring 13,800 GWh

[12] In the decreasing-cost natural-monopoly case with lumpy investment, the usual design for a two-part tariff sets the average revenue equal to long-run average increment cost, with the marginal price set to reflect short-run marginal cost. Thereby, both long-run and short-run price signalling efficiency can, in principle, be achieved. The increasing-cost case considered here is incompatible with such a first-best-type outcome.

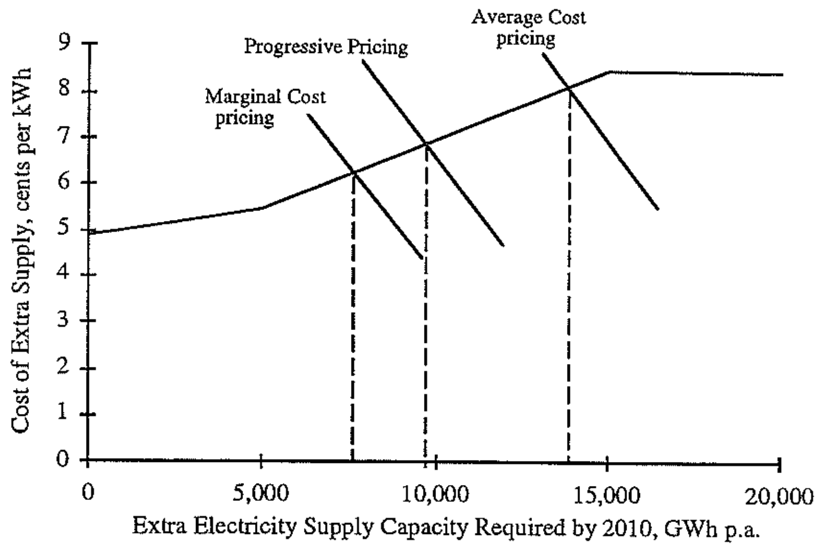
[13] Note, though, Coase's (1946) passing reference to the sunk cost problem.

[14] When Park (1989, p. 58 and pp. 61-63) comes to address the topic of "Excess Revenue at First-Best Prices", he retains the assumption of a linear price schedule and resorts to a shamelessly wasteful mechanism for dissipating rents, namely bringing forward investment in new capacity as a means of raising the monopolist's costs and thus reducing profit.

[15] If price elasticity of demand is around −0.5, this is consistent with the BERL modelling results for electricity demand shown in Figure 7 below.

p.a. of additional capacity and pushing incremental cost to around 8 cents per kWh.

Figure 7. Results of 1994 BERL Model Scenarios Comparing Pricing Options



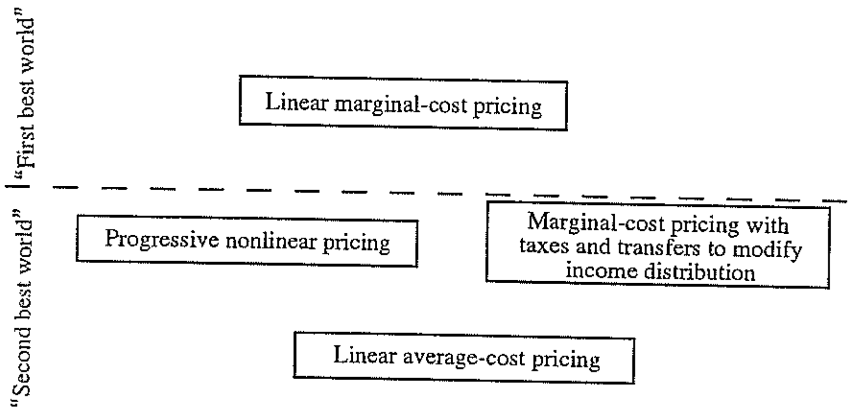
The model's finding that progressive pricing would cause demand by 2010 to be 5% greater than under marginal-cost pricing, thereby adding 0.8 cents per kWh to the marginal price, appears to have been influential in the eventual decision by the Government to proceed with a linear-pricing approach. There are, however, important deficiencies in the specification and interpretation of this CGE modelling exercise.

The two most basic flaws are the failure of the Officials' Committee to deal explicitly with the income constraint issue, and the absence of any scenario which tested a lump-sum tax-transfer option against progressive pricing. The result is that Cabinet was presented with an incompletely specified set of choices.

The actual hierarchy of options is set out in Figure 8. It is easy to agree that, in the absence of any political obstacle, full competitive marginal-cost pricing is the optimal regime. The first step, therefore, should have been for the Government to decide whether the profit consequences for ECNZ of this pricing option were socially acceptable. Only if there is an income constraint is it necessary to explore the policy choice among the second-best options (progressive pricing, average-cost pricing, and lump-sum taxes/transfers). Ranking marginal-cost pricing against progressive pricing as Figure 7 does, without reference to any distributional constraint, is an exercise of no analytical merit.

Progressive pricing should dominate any second-best linear price, for theoretical reasons already discussed, and this ranking is strongly confirmed by the BERL modelling results shown in Figure 7. The second-best policy choice would then come down to a contest between progressive pricing and lump-sum transfers (rebates). This choice, however, was not modelled and officials had no recommendation to offer on it, apart from their implicit suggestion that lump-sum transfers have no general-equilibrium implications (in which case the tax-transfer option would be preferred over progressive pricing, on the basis of the BERL model results). Such an absence of economy-wide feedbacks and income effects, however, is not something that can safely be assumed in this case.

Figure 8. Decision Hierarchy of Electricity Pricing Options



There has been some New Zealand CGE modelling of scenarios in which an increased linear price is imposed on electricity consumers, with the resulting additional revenues to the government either absorbed as a reduction in the budget deficit (Frater, Philpott, Nana, Harris and Miller, 1985; Bertram, 1992) or "recycled" as transfers to households (Bertram, 1992). However, the recycling mechanisms used in the 1992 work (reduced income-tax rates, and a reduction in the rate of GST) are not exactly lump-sum, and hence the results are only indicative. Indications from that work are that, given the significance of the electricity sector in the New Zealand economy, there are important economy-wide effects of any tax-transfer mechanism. Capturing excess surplus from ECNZ by means of dividends to the Government, and then distributing a matching amount to households as transfers, has the same effects as any income transfer from profits to wages, namely a tendency to raise consumption and weaken the balance of payments, while having an unclear impact on aggregate investment. The idealised concept of a lump-sum transfer which is entirely neutral in its effects on resource allocation has not yet been made operational in the New Zealand electricity pricing debate. Indeed, given the fact that electricity is used more as an intermediate good than as a final consumption good (in terms of the CGE models currently in use), it is difficult to imagine a tax-transfer mechanism that did not have significant economy-wide implications.

CGE modelling cannot, however, address the public choice issues raised by the tax-transfer option. It was scepticism about the ability of government to transfer income from consumers to a natural monopolist in a non-distorting fashion that led Coase (1946) originally to propose non-linear pricing as a viable alternative, and it is not clear that transfers in the other direction are immune to his critique. Certainly, there has been a strong undercurrent of opinion in New Zealand policy circles during the past decade which has preferred contract-based market mechanisms to government-mediated transactions, and this stream of thought has been a major influence on energy market restructuring.

5. Conclusion

In June 1995 the Government announced its decision to split ECNZ into two competing SOEs and to leave the wholesale electricity price to be determined competitively in the marketplace, overhung by an implicit threat of future price control if the price at any time exceeds the limits of what is politically acceptable.

Two changes in policymakers' perception of the issues relating to wholesale electricity pricing seem to have contributed to this decision. One was a steady series of downward revisions in the expected average increment cost of new generating capacity, which made the expected wholesale price increase less intimidating. Prices for coal and gas (the main fuels for new increments to capacity) became softer, while costs of windfarms and other renewable technologies fell steeply in the first half of the 1990s to the point where new investment projects began to be undertaken, although all such projects to date have been designed to be embedded in distribution networks.[16] The data plotted in Figure 7 indicate the more optimistic official view on the cost of new capacity, with around 5,000 GWh p.a. estimated to be available at 5 cents per kWh or less. With 3,000 GWh of excess capacity already installed, sustained upward pressure on the wholesale price arising from increasing incremental cost was considered no longer an immediate threat. Officials went well beyond even their model results, advising the Government that "the price of electricity should not rise significantly over the next fifteen years" (Officials' Committee on Energy Policy, 1995, p. 4).

The second change was a lessening of the distributional constraint on electricity pricing, at least as perceived (subjectively) by politicians. Economic growth revived from 1992 on and the economic hardship faced by politically influential parts of the community fell accordingly. In this more buoyant economic climate, an increase in the wholesale electricity price became easier to defend politically.

The basic issue which prompted the early-1990s debate over non-linear pricing, however, has not altogether disappeared. Under the 1992 Framework Convention on Climate Change, New Zealand is moving towards policies which will restrain emissions of carbon dioxide. A major source of such emissions is electricity generation using gas and coal. Imposition of a substantial carbon tax would again raise the cost of incremental generation from these sources, with the accompanying prospect of windfall profits for the owners of existing hydro capacity. A progressive-pricing mechanism might then regain some political appeal.

[16] Embedded generation enables retailers to bypass the high-priced transmission grid and the emerging wholesale pool arrangements. Such strategic considerations significantly improve the expected profitability of embedded windfarms and combined-cycle gas-fired plant. From a national viewpoint, the result is distortionary, being attributable to government-driven overvaluation of the grid assets in pursuit of short-sighted fiscal objectives.

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