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Under-pricing electricity and the puzzle of regulatory accounting

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Keywords State-owned utilities, electricity investment, pricing, accounting, cost of capital

JEL Classification L32, L51, L94

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30 July 2008

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1. The pricing puzzle

State-owned electricity supply industries (ESIs), particularly in developing countries, find it hard to finance investment from either internal funds or borrowing from the state, and thus are under increasing pressure to turn to the private sector, either via privatisation or by long-term contracting (known as Power Purchase Agreements, or PPAs) with the private sector (normally Independent Power Producers, IPPs). In both cases a typical problem is that electricity prices are below the long-run marginal cost (LRMC) that would be adequate to compensate new investment. If investment is needed, then privatisation with a competitive wholesale market will be unsuccessful unless prices rise to LRMC. If that happens after privatisation, private investors stand to make a politically unacceptable windfall profit on the existing assets. If prices are raised to LRMC before privatisation, then many of the reasons for privatisation (inability to finance investment) may thereby be solved. Avoiding that dilemma via PPAs with IPPs risks the credibility of those PPAs, as consumer advocates will criticise the mismatch between the IPP price and the electricity sales price. As the share of IPP power increases, either retail prices must rise, or the electricity company faces bankruptcy, common features of the Indian ESI (Newbery, 2007).

One common feature of many ESIs, and notably of generation, is that the book value of assets is far below their modern equivalent asset (MEA) replacement cost, or their Optimal Deprival Value (ODV) – the value the business would need to be paid to adequately compensate for being deprived of the asset.[2] There are two possible explanations of this – the first that with inflation the original book value of the asset under Historic Cost Accounting (HCA) will fall increasingly below its MEA value. The second is that assets are typically depreciated on a straight-line basis over a conservative estimate of its lifetime, so that fully depreciated assets may still have considerable economic life remaining.

This paper investigates whether the explanation for the systemic under-pricing of electricity in state-owned enterprises (SOEs) is the choice of historic cost accounting, and shows that this is an inadequate explanation. Instead the real explanation seems to be a systemic failure to charge an adequate real rate of return on capital in SOEs, which, for capital-intensive enterprises like the ESI, leads to serious under-pricing of not only capital but output, and a consequential difficulty in financing new and replacement investment.

The first question to answer is whether traditional cost-of–service regulatory accounting as practised in, for example, the U.S. under HCA conventions, will systematically under-value

[2] MEA accounting is equivalent to ODV provided the asset is worth retaining, otherwise the ODV may be less than the MEA. MEA valuations are more familiar in standard accounting, while ODV is a regulatory concept particularly favoured in Australia (see ACCC, 1998; IPART, 1998; Clarke, 1998). Whittington (1998) discusses similar accounting concepts for the UK.

assets and lead to regulated prices that are below the LRMC, i.e. the price (and price projections) needed to compensate new investment. If not (and that seems to be the case) the logical inference is that the capital cost component of the price is too low, implying too low a required rate of return. The paper presents a variety of evidence supporting the view that the state systematically sets too low a rate of return. The final question is how prices should be set to ensure that investment can be financed when needed.

2. The long-run marginal cost of generation

What is the long-run marginal cost (LRMC) of new generation capacity and in what sense is it a suitable benchmark against which to compare average electricity prices? This is not a simple question, unless (efficient) prices and costs are constant in real terms. The benchmark competitive market would determine an instantaneous price for generation at each moment and, given perfect foresight so that investment occurs as it becomes profitable, will in turn correctly value capacity at each moment, thereby also determining the correct value of depreciation. The LRMC will then be the price at each moment assuming optimal investment. In an unchanging world this is equivalent to finding the levelised[3] cost of investment. It may be contrasted with rules that depreciate the investment cost over some lifetime, typically linearly, and then compute the capital cost as the interest on, and depreciation of, the resulting asset value, to which would be added the variable cost to give a regulated price.

The simplest case is an unchanging world in which investment and fuel costs remained constant (in real terms) over time, although the variable costs of a particular station might increase with age as maintenance expenditures rise. Suppose that real variable costs (fuel, labour, maintenance) and the electricity price remain constant.[4] This price, p, is then equal to the LRMC if the PDV of gross profits is equal to the investment cost, k, per MW of capacity, for a plant that runs f hours per year[5] with unit variable cost c and an *economic* life of T years:

$$k = \int_0^T f(p-c)e^{-ru}du = f(p\ \phi(r,T) - c\phi(r,T)),$$

where $\phi(g,T) = (1\text{-}e^{-gT})/g$, and r is the real rate of discount. This can be solved for p:

$$p = c + \frac{k}{f\phi(r,T)}. \tag{1}$$

The value of a 1 MW plant of age t will be

[3] The levelised cost is the constant (real) price that gives rise to a flow of gross profits that when discounted over the life of the asset is equal to the investment cost.
[4] It is straightforward to allow maintenance costs to rise from an unchanging initial level over the life of the plant.
[5] The load factor as a percentage will then be $100f/8760$. Thus a plant running for 7,000 hours per year will have a load factor of 80%. Note that 1 MW (megawatt) = 1,000 kW or kilowatts.

$$V_t = \int_t^T f(p-c)e^{-r(u-t)}du = f(p\ \phi(r,T-t) - c\phi(r,T-t)). \qquad (2)$$

The rate of change of this value will be

$$\frac{dV_t}{dt} = -fp + rV_t\,.$$

This can be rewritten to show that the annual gross profit is equal to $rV_t - dV/dt$, confirming that depreciation is the fall in value, $- dV/dt$. Put more directly, if asset values and depreciation are correctly calculated, it will be the case that the price should be the operating cost plus the interest on and depreciation of the current asset value.

2.1 *Regulatory accounting*

If the plant were subject to standard regulatory cost accounting, then it would have a book value at any date written down by the rate of depreciation, which conventionally would be k/L, where L is the deemed life of the asset, to be contrasted with the *economic* life, at the end of which the ODV has fallen to zero. A plant of age u will then have book value $k(1\text{-}u/L)$ and will be allowed to claim $rk(1\text{-}u/L) + k/L$ in capital charges and $c_0e^{au}f$ in variable operating costs (opex), earning regulated revenue $p_{ru}fh$ when age u (all per MW of capacity). Parenthetically, it is easy to confirm that the present value of this stream of interest and depreciation payments will exactly pay for the capital as

$$k = \int_0^L (rk(1-\frac{u}{L}) + \frac{k}{L})e^{-ru}du.$$

If the regulated price, p_{ru}, were set to ensure that the plant covered its total accounting cost at age u, then

$$p_{ru}f = rk(1\text{-}u/L) + k/L + cf,$$

$$p_{ru} = c + \frac{k}{f}(r + \frac{1-ru}{L}), \qquad (3)$$

which differs from (1) at date zero (and most other dates).

How material is this change in accounting? Consider a coal-fired plant in which the initial fuel and O&M costs are \$8/MWh, capital costs are \$1.6 m /MW, the plant life is 40 years, and operates at f = 7,000 hrs per year (load factor is 80%),[6] with r = 8% real. The correct value for p = \$29/MWh, and depreciation *increases* over time (in contrast to straight line depreciation where it is constant) because the interest on the declining capital value falls (their sum being

[6] These costs are plausible for a South African coal-fired power station, given the very low cost of coal there, as stations typically burn low-value coal that is uneconomic to export. For most countries the fuel costs will be a higher proportion of the final price, but different accounting principles do not affect the fuel cost element and so the overall distortion is likely to be highest for low fuel cost cases.

gross profit). In contrast if one takes a simplistic view and amortises the investment over the 40 years on a straight-line basis, the initial price p_{r0} = \$32/MWh, or 10% higher. If the plant were amortized over 30 years (i.e. a conservative 75% of its economic life) then the initial price would be 17% too high.

However, it is obviously misleading to consider one plant in isolation and just one date (that of investment). If all plant were of the same age and the price were set on this basis (current cost accounting on the depreciated regulatory asset base, or RAB), then the accounting price would fall to the economic price in year 19, and by year 40 would be only 88% of the correct cost. Clearly the accounting should be done for an entire company with plant of varying ages, to see whether there is a systematic under-pricing for a company with both new and old plant. To explore how conventional regulatory accounting might distort prices we need a model of capital accumulation and accounting valuation.

3 Company accounting measures

The simplest case to consider is one of steady growth with unchanging real fuel and investment costs. Suppose that in year t, m_t MW of capacity are added, and each plant generates for f hours/year reliably until when it is T years old it suddenly fails permanently (and has zero scrap value). Annual output (and capacity) are growing at rate g and output at date t, y_t, is given by

$$y_t = y_0 e^{gt} = \int_{t-T}^{t} m_0 f\, e^{gu}\, du = m_0 f\, e^{gt}\, \phi(g,T). \tag{4}$$

The investment cost in year t is $ke^{it}m_t = km_0e^{(i+g)t}$, where the cost of 1 MW of generation capacity is k at date zero and the annual inflation rate is i.

The economic value of the company (its ODV) will be the present value of the existing assets, or the sum of the ODV of plants of each age. The simplest case is that of constant operating cost over the life, so that a = 0, for then the value of a 1 MW plant of age u is, from (1) and (2):

$$V_u = \frac{k\phi(r,T-u)}{\phi(r,T)}. \tag{5}$$

The total value of the company at date t (at date t prices) is

$$\begin{aligned} V &= e^{(g+i)t}\int_0^T V_u m_0 e^{-gu}\,du = km_0 e^{(g+i)t}\int_0^T \left(\frac{e^{-gu}-e^{-rT}e^{(r-g)u}}{1-e^{-rT}}\right)du \\ &= \frac{km_0e^{(g+i)t}}{1-e^{-rT}}\left(\frac{1-e^{-gT}}{g}+\frac{e^{-rT}-e^{-gT}}{r-g}\right). \end{aligned} \tag{6}$$

The first question we can now address is to what extent a company following economic valuation principles can finance investment in steady-state growth. The annual real cost of investment will be km_0e^{gt} and the gross profit (in real terms at date 0 prices) in that year will be

$$\pi_t = e^{gt}\int_0^T m_0 f(p-c)e^{-gu}du = e^{gt}m_0\{f(p\ \phi(g,T) - c\phi(g,T)\}. \qquad (7)$$

Substituting for p from (1)

$$\pi_t = e^{gt}km_0\phi(g,T)/\phi(r,T)\}. \qquad (7a)$$

The required rate of savings out of gross profits to sustain steady growth will be the ratio of the real cost of investment, km_0e^{gt}, to real profits, π_t, $\phi(r,T)/\phi(g,T) < 1$, provided $g < r$. (If rT is small the ratio is somewhat more than g/r.)[7] Thus if g = 8% and r = 10% for T = 40, the savings rate would need to be 82% for complete self-finance. If g = 5% and r = 10% the savings rate would only need to be 57%. It suggests first, that the company should use a *real* cost of capital greater than the growth rate of investment if it is to be able to finance investment, and second, that a failure to be able to 100% self-finance is probably indicative of under-pricing (or possibly lumpy investment, in which case medium-term borrowing should resolve the problem).

3.1 *Regulatory accounting*

If the utility is following regulatory accounting with straight line depreciation over a deemed life of L years (typically less than the economic plant life), then the asset value at date t summing over plants of age u will be, under historic cost accounting (HCA) rules, allowing for inflation at rate i:

$$\begin{aligned} B_t &= \int_0^L km_0 e^{(g+i)(t-u)}(1-\frac{u}{L})du \\ &= km_0 e^{(g+i)t}\psi(g+i,L), \quad \psi(m,L) = \left(\frac{e^{-mL}-1+mL}{m^2L}\right). \end{aligned} \qquad (8)$$

If accounting is done under current cost accounting (CCA) rules, then i in this formula is set equal to zero.

The ratio of book value under regulatory accounting to the ODV is B_t/V, which can be evaluated from equations (6) and (8). Thus under CCA, with L=T (i.e. the correct lifetime for depreciation), r = 8%, other costs as before, and with g = 5%, the ratio is 77%. If L= 30 years the ratio drops to 65%, and if instead of 5%, g = 2%, the ratio drops further to 57%. Under HCA (at year zero prices), with L=T, g = 5%, and inflation i = 5%, the ratio is 51%, while with L= 30 the ratio drops to 46%. Figure 2 shows how the ratio varies with the ratio of growth to discount rates for various rates of inflation and assumed asset lives.[8] The plots with zero inflation also

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[7] That suggests taking the ratio g/r is an appropriate normalisation when making comparisons, as in figures 2 and 3 below. More generally, one would expect the discount rate to be higher for fast growing economies (and the social discount rate is typically taken as $\nu g + \delta$ for an inequality aversion parameter ν (often taken as ν = 1) and pure time preference rate, δ.

[8] Footnote 7 explains why g/r is a suitable normalisation, although figure 2 is drawn for a single r=10%

correspond to CCA regulatory accounting.

Thus it does indeed appear that regulatory accounting can lead to the under-valuation of company assets, which is exacerbated by shorter depreciation periods, higher rates of inflation and lower rates of growth (of investment).

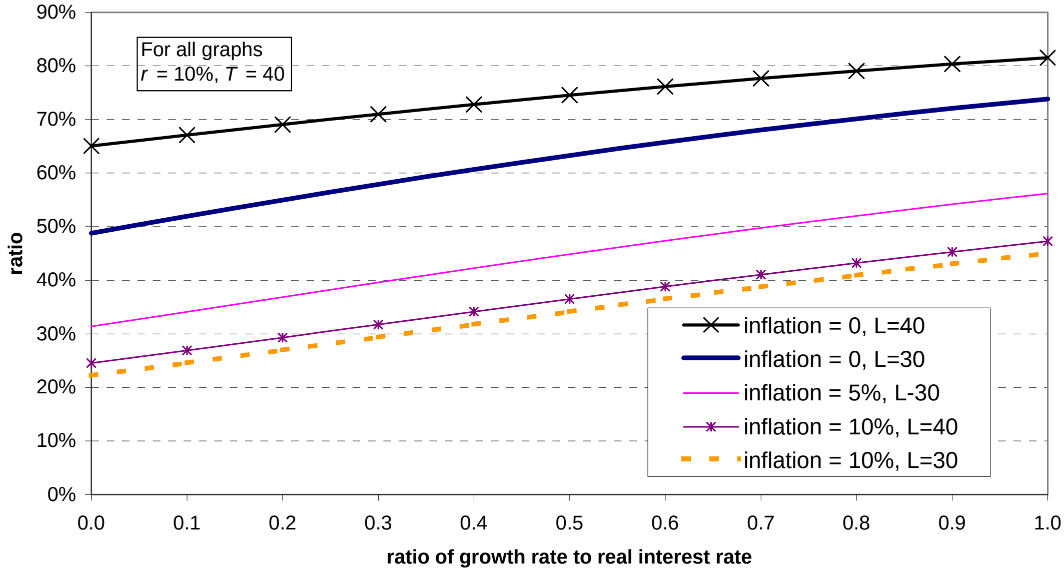

Figure 2 Variations in the ratio of HCA book value to ODV for varying inflation rates and asset lives

Regulatory depreciation allowances will be

$$D_t = \int_{t-L}^{t} \frac{km_0 e^{(g+i)u}}{L} du = \frac{km_0 e^{(g+i)t}}{L} \phi(g+i, L). \tag{9}$$

Again, under CCA, i would be set at zero. The allowed capital revenue will be $(r+i)B_t+D_t$ spread over the y_t MWh, to which will have to be added opex (fuel + O&M) to give the regulated price. The capital charge per MWh will be c_k:

$$\begin{aligned} c_{kt} &= \frac{ke^{it}}{f\phi(r,T)} \frac{\phi(r,T)}{\phi(g,T)} \{(r+i)\psi(g+i,L) + \phi(g+i,L)/L\} \\ &\equiv \frac{ke^{it}}{f\phi(r,T)} \Theta(r,g,i,L), \quad \Theta(r,g,i,L) = (r+i)\psi(g+i,L) + \phi(g+i,L)/L. \end{aligned} \tag{10}$$

which has been written as the product of two terms, the first being the same as the capital element in (1). In terms of year zero prices, the capital charge is constant. Under CCA rules, the allowed capital revenue would be rB_t+D_t, which can be evaluated by setting $i = 0$.

The average accounting cost of electricity is the capacity cost per unit (given above) plus the average variable cost of generation, which is given by $c_{vt} = c_0 e^{it}$ at date t. The average regulated cost of electricity will then be $p_{rt} = c_{kt} + c_{vt}$ which can be compared with $p_t = pe^{it}$ from (1):

$$p_{rt} = c_0 e^{it} + \frac{ke^{it}}{f\phi(r,T)}\Theta(r,g,i,L). \qquad (11)$$

There are three possible sources of difference concentrated in the multiplier Θ(*r,g,I,L*): *g* replaces *r*; the depreciation period *L* will typically be shorter than the economic lifetime, *T*; the accounting might be at HCA, in which inflation at rate *i* must be included in various places (but not for real items such as total output), and as a result the discount rate is the nominal, rather than real, rate.

To tease out the various influences, suppose *L*=*T*, (the correct lifetime), CCA (so no inflation bias), and take the same cost data as before with *g* = 5%. Then *p* = $27/MWh, and although the first term in (11) is just the variable cost, and the same as in (1), the second term is multiplied by Θ(*r,g,I,L*). In this case the multiplier is 0.93, and the average cost (and price) will be $25.7/MWh, 5% lower than the correct price. Under HCA and inflation of 5%, the multiplier is 0.85 and the price is 11% lower than the efficient level.

In the special case in which the rate of growth is equal to the rate of discount, *r*=*g*, the factor will be exactly 1 and there will be no bias, as

$$r\psi(g,L) + \frac{\phi(g,L)}{L} = g\left(\frac{e^{-gL} - 1 + gL}{g^2 L}\right) + \left(\frac{1 - e^{-gL}}{gL}\right) = 1, \qquad (12)$$

regardless of the depreciation period, *L*. Lowering the growth rate to 2% (which considerably reduces the ratio of book value to correct value) and setting *L* = 30, moves the price to 83% (CCA) or 76% (HCA) of the LRMC. Even raising the inflation rate to 20% only moves the HCA price to 67% of LRMC (provided the nominal interest rate reflects the rate of inflation).

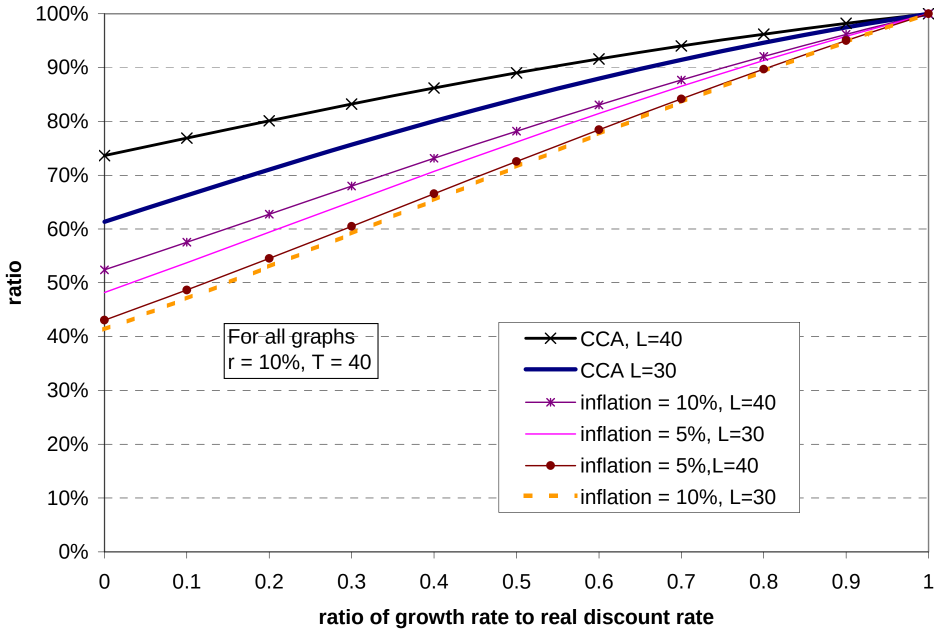

Figure 3 Ratio of capital cost under regulatory accounting to the economic charge

Figure 3 plots the ratio of the capital charge when computed using HCA regulatory accounting to the economic cost in steady growth. In both cases the prices would be equal to the capital charge plus the variable cost. The graphs confirm that at $r = g$ the ratio is 1, and that the ratio is lower at higher rates of inflation, lower rates of g/r, and shorter assumed asset lives, but that for reasonable growth rates the ratio is remarkably high.

The next question is to see how regulatory accounting deals with the ability of the company to finance investment. Gross real profits are then

$$\pi_{at} = m_0 k e^{gt}(r+i)\psi(g+i,L) + \phi(g+i,L)/L. \tag{13}$$

The required rate of saving is

$$\frac{1}{(r+i)\psi(g+i,L) + \phi(g+i,L)/L}, \tag{14}$$

which, for the savings case discussed above (g = 8%, r = 10%, T = 40, but with L = 30 and i = 5%) gives 90% (up from 82%) while at g = 5% and i = 10%) the savings rate must be 79% instead of 57%. Regulatory accounting thus makes it harder to self-finance investment, although provided the regulator or state allows a proper (nominal) weighted average cost of capital (WACC) on the investment, the revenue streams will be enough to pay off any borrowing at that rate.

4. The puzzle of regulatory accounting

Although there is apparently considerable under-valuation of assets under regulatory accounting, this is partly offset by the higher average rate of depreciation, while inflation, provided it does not reduce the real rate of interest, leads to increasing under-valuation of capital but is partly offset through the higher nominal return on those assets. Surprisingly, proper regulatory accounting, even with straight-line depreciation and HCA, should result in an estimated LRMC that is fairly close to the efficient level when rates of growth are high (thus for L = 30, r = 10%, g = 8%, i = 10%, the HCA accounting price is 92% of LRMC. Full CCA consistently applied typically brings the estimate even closer (to 96% in this case).

We therefore have an apparent puzzle – observed electricity prices are frequently too low even when demand growth is high, but this would not seem to be the result of the form of accounting and price determination, at least in a steady growth economy with stationary real input and output prices.[9] There are several possible explanations of under-pricing. One is that is that prices have been held down below the level indicated by regulatory accounting – which is likely for state-owned enterprises (SOEs) that do not have to meet predefined contractual rates of return during inflationary episodes. This explanation is amply illustrated

[9] Bear in mind that taking a low fuel cost exaggerates the discrepancy, so low electricity prices in countries with higher fuel costs would be even harder to understand.

in *Bureaucrats in Business*, (World Bank, 1995). Transfers to SOEs (measured as savings minus investment) were running at 3% of GDP in the late 1970s, recovered somewhat in the mid-1980s, but fell back to 2% of GDP in the 17 low-income countries studied. This is an imperfect measure of the extent of inefficient pricing, as it is reasonable to borrow if future demand growth accelerates or investment needs are bunched (investment will then exceed savings), and similarly a decrease in net savings may just indicate a decrease in investment needs, not an improvement in pricing. Nevertheless, the persistence of deficits in many countries strongly suggests under-pricing, and this is confirmed by reports that compare prices with LRMC.

Another explanation is that the accounting has been properly done, prices have been set at the appropriate regulatory level, but past over-investment resulted in a subsequent period of low investment, until the initially high reserve margin has fallen to the level at which new investment is needed – a not uncommon situation following the fall in projected electricity demand growth rates after the 1970's oil shocks. This second explanation, that good accounting principles were followed but nevertheless resulted in under-pricing, is theoretically more interesting, and may explain the problems currently facing Eskom, South Africa's SOE and the seventh largest electricity company in the world.

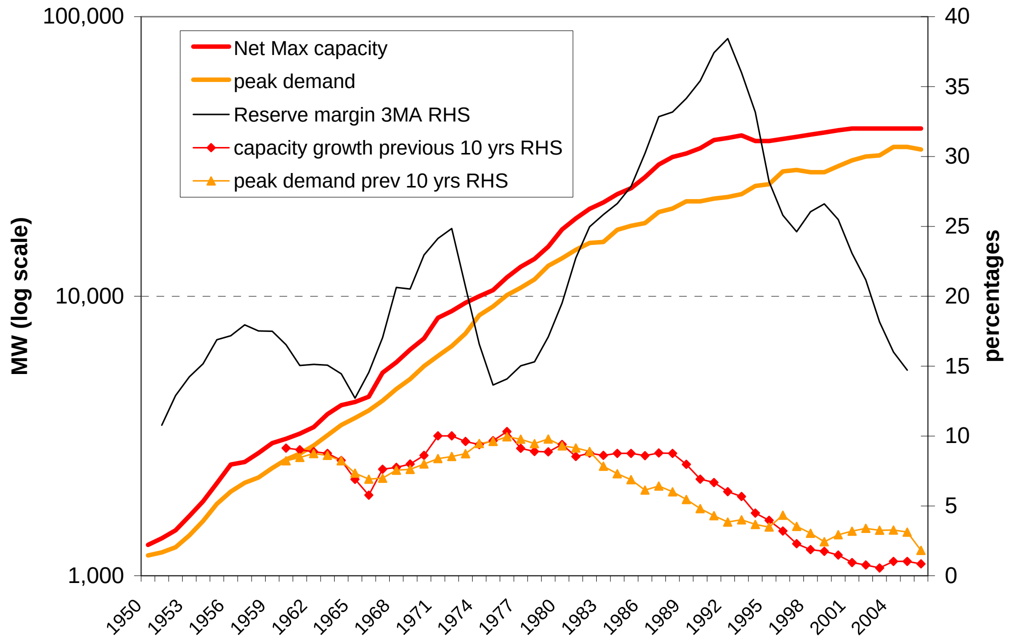

Figure 4 Eskom's net capacity, peak demand, reserve margin 1950-2006
Source: Eskom

Figure 4 shows the evolution of Eskom's net generation capacity and peak demand on a log scale (so that lines of constant slope are steady growth rates). The lower two plots (with diamonds and triangles) gives the backward-looking growth rates of net capacity and peak demand over the previous 10 years, shown on the right-hand scale, which also shows the reserve margin (capacity-peak demand/capacity). Demand and capacity grew at about 9% in the 1950s and at even higher rates in the 1970s and 1980s, although peak demand growth was falling. Initially the capacity margin was below the comfort level of 20% (for a coal-fired system with high growth rates). The move to larger generation units and higher efficiencies designed for higher quality UK coal in the late 1960s resulted in considerable teething problems with poorer SA coal, and resulted in low availability. Eskom reacted by ordering more capacity to address shortages, and then over the following years managed to increase the availability of this new plant, so that Eskom's reserve margin rose dramatically from 1976 to 1992. This eliminated the need to add capacity and for the past two decades little capacity has been added and capacity growth has been systematically below demand growth, leading to a rapid fall in the reserve margin.

If we plug some of these numbers into the formula for the period of steady growth (at g = 9%, r = 10%, L=30, T = 40, inflation (which was averaging over 10% p.a. until 2000), i = 10%, then the ratio of the regulatory price to LRMC is 96% under HCA, whereas by 2007 the actual ratio was less than 50%. Under steady investment, HCA accounting cannot explain underpricing, and so we need to look at the effect of investment holidays, as in South Africa.

4.1 *Investment holidays under backward looking accounting*

Cost-of-service regulatory accounting is backward looking, in that it seeks to reward past investment and thus maintain the credibility of the regulatory compact and hence continue to reassure private investors that they will not be expropriated (Gilbert and Newbery, 1994). Competitive markets are forward looking in the sense that the current price reflects the degree of scarcity, which is the outcome of past and current investments that are motivated by expected future prices. The LRMC is an essentially forward-looking concept, and a current price can only be said to be adequate for investment when combined with some view of prices over the prospective life of that investment. In steady growth, forward and backward looking views are closely linked together, which in part explains why backward-looking regulatory price-setting is so close to efficient or LRMC price-setting.

The results of a higher rate of growth of capacity than demand, followed by an investment holiday, particularly when combined with inflation, can have a dramatic effect of the relationship between the regulated price and LRMC. Suppose that capacity and output were both growing at g before date 0, but afterward demand grows at rate $m < g$, while capacity continues to growth at rate g. If capacity was optimally adjusted at date 0 (when the paths diverge), then the capital charge of (10) will thereafter be replaced with

$$c_{kt} = \frac{ke^{(g-m)t}}{f} \frac{(r+i)\psi(g+i,L) + \phi(g+i,L)/L}{\phi(m,T)}, \tag{10a}$$

(measured at year zero prices) which is no longer constant but will evolve over time. If we compare the HCA regulatory price 12 years after the growth rates diverge with the LRMC (also at year zero prices), and take m = 5% and g = 8% with i = 10% (and L =30, T = 40, a = 0, r = 10%) then the ratio of regulatory price to LRMC is 89%. Had capacity only (ever) grown at 5% the ratio would have been 79%. The excess capacity per unit of actual output (the term $e^{(g-m)t}$) raises the unit capital cost by 43% and to some extent offsets the under-valuation in the book value of capacity.

If investment were to stop K years after the paths diverged (taken as year 0), with no further investment until the excess capacity were eliminated, there would be no investment until $t = gK/m$ years after divergence. By that time the nominal book value will have fallen to

$$B_t = km_0 e^{(g+i)K}\psi(g+i, L-(g/m-1)K)(1-(g/m-1)K/L), \qquad (7a)$$

and depreciation is then

$$D_t = km_0 e^{(g+i)K}\phi(g+i, L-(g/m-1)K)/L. \qquad (9a)$$

The accounting capital cost $(r+i)B_t+D_t$ can then be calculated and averaged over the output of $m_0 fe^{mt}\phi(m,T)$ and added to the variable unit cost $c_0 e^{it}$ to give the average regulated price. With the earlier figures the zero investment phase will last $(g/m\text{-}1)K$ = 7.2 years. The effect is to lower the HCA regulatory price to 60% of LRMC (and 62% under CCA). Surprisingly, the ratio is relatively insensitive to inflation (provided it is steady over the whole life of the surviving plants).

Thus a break in investment combined with regulatory accounting can explain a certain amount of under-pricing, even when the regulatory rules are followed and the real rate of interest remains constant (so the nominal rate increases by the real rate). This last assumption may not be warranted if the company issues nominal bonds in a period of expected low inflation, if when inflation rises, the relevant weighted average cost of capital (WACC) is taken as the average interest payments on the nominal value of the debt. With capital costs comprising about 75% of the (wholesale) price in this case (Eskom has access to very cheap coal) any reduction in the allowed WACC would have a considerable effect on the allowed capital cost. The insensitivity of the correctly computed price to inflation relies on the increase in the nominal WACC offsetting the under-valuation of the book value. That suggests an alternative and more convincing reason for under-pricing – a failure to charge the appropriate cost of capital.

5. The explanation: state-owned enterprises subsidise lending

If companies adopt proper accounting and a commercial rate of return, then pricing may deviate from its economic level, but the deviations seem modest when compared to evidence of serious under-pricing in many countries. Moreover, real electricity prices have often fallen quite dramatically compared with earlier periods. In South Africa, Eskom's average retail price fell 35% between 1987 and 1999,[10] a considerable amount but less than in Hungary, whose real domestic electricity prices fell by 56% between 1970 and 1990, despite a real increase in fuel prices over that period (Newbery, 1999). A common theme is that prices were

[10] Eskom historical data can be found at http://www.eskom.co.za/content/TariffHistory.pdf

kept high in the past to finance often massive investment programmes, notably in the post-war catch-up period, but once that financial pressure was reduced, the SOEs were under weak budgetary pressure to maintain real prices in the face of general inflation, and given the often very minimalist target required rates of return they were instructed to achieve.

An excellent example of the undemanding required rates of return is the Indian Electricity (Supply) Act (1948) that prescribes that each State Electricity Board (SEB) earn a minimum return of 3% (nominal). In fact they rarely achieve even that. The 1997/98 *Economic Survey* showed the overall rate of return fell to -17.6%. Ruet (2005, p13) noted that "by early 2001, SEBs (State Electricity Boards) as a whole faced an average 50 per cent level of technical plus non-technical losses, and they collectively owe around $5 billion to the Government of India undertakings." Even in Britain the achieved real rate of return by the UK Central Electricity Generating Board over its entire post-war history until it was sold (and hence its assets valued by the market) only achieved a 2.7% real internal rate of return (Newbery and Green, 1996, p56).[11] The evidence supports the theory that the state as owner seems reluctant to treat its capital assets as sources of income, and hence reluctant to require an appropriate rate of return.

Thus the simple explanation for under-pricing electricity is that state-owned electricity companies charge a low return on their capital assets, often failing to adjust any required rate of return from nominal to real values, and falling considerably short of commercial rates of return. Thus Eskom reports a rate of return in 2007 of 7.8% on total assets,[12] when the inflation rate was 5% (down from 10% in 2003), so the real rate of return was only 2.8%. Part of the problem may be a confusion between nominal returns on HCA book valued accounts and what are in effect real returns to equity (dividend yields are related to share prices which over time adjust for inflation). SOEs like Eskom often report the return to "equity" but this is just the return less interest payments on the HCA book value less debt, and hence is not a market rate of return.

So what rate of return should state-owned electricity companies earn? Diamond and Mirrlees (1971) argued that efficient public sector pricing and investment of marketable goods required using the same set of prices as a competitive private sector, and in particular that the rate of return should be equal to the suitably risk-adjusted private rate of return.[13] In a world in which governments are financially tightly constrained, and where the marginal cost of raising taxes can be high, not to charge a commercial return on state assets, and thus in effect to subsidise loans, is almost criminally negligent.

[11] As the average rate of inflation was 6.9% this translates into an average *nominal* rate of return of 9.6%.

[12] Defined as net operating income expressed as a percentage of total assets, which are reduced by financial market assets and interest receivable (Eskom's *Annual Report 2007*).

[13] Given a set of not-unreasonable assumptions, that externalities have been internalised, that the tax system is potent, and that public sector under-pricing does not give extra distributional leverage that cannot be better achieved through the tax and benefit system.

6. Economic pricing for a franchise electricity company

Regulatory pricing runs into difficulties if the regulated price departs too far from the LRMC. If, as in California, the regulated price is above the cost of new gas-fired entry (because of the legacy Qualifying Facility contracts and past nuclear investments), there will be pressure to liberalize the market, although the inefficiencies of allowing excess entry driven purely by high regulated prices can be mitigated by imposing Competition Transition Contract charges on those buying in a competitive wholesale market (as in California and Spain). If the regulated price is too low, then it may be hard to finance new investment and hard to liberalize without giving windfall profits to incumbents as wholesale prices rise to the efficient level.

The obvious problem with regulated prices is that they are backward looking, failing to account for changes in the least cost plant (e.g. the switch to gas from nuclear, or v.v. with recent high gas and carbon prices), and that they are average, not marginal costs. With excess capacity, average cost pricing means prices tend to be too high, while with tight capacity prices can be too low. In a liberalised competitive market the opposite would be the case – real option value theory indicates that prices with excess capacity will be below average cost, but will have to rise considerably above the notional LRMC (i.e. the constant real price that if maintained would be the LRMC). The lost option of making an investment (rather than delaying to see what might happen to the demand-supply balance) must be reflected in a premium, while the risk of future low prices because of periodic over-supply must also be compensated, both in the risk premium that feeds into the WACC and in the real option mark-up.

There are several possible remedies for this failure, and they all require a more forward-looking approach to regulation, as has become standard under the British system of setting periodic price controls with inflation linking ("RPI-X", meaning that prices are allowed to increase in line with the retail price index, less an efficiency factor, X). Under this system the vertically-integrate electricity utility submits its investment plans and is allowed to earn its WACC on the efficient cost of those plans, plus depreciation. With a price-basked system of regulation, the utility would then also choose an efficient set of prices (for peak, off-peak, industrial, domestic, transmission and distribution tariffs). One might then expect (or positively encourage) the resulting set of tariffs to mimic a standard Power Purchase Agreement (PPA), in which the wholesale price is a two-part tariff, with a capacity payment that over the life pays for the capital cost, and an energy price. The capacity payment can then be included with the transmission tariff, and spot electricity would be sold at the system *marginal* energy price. The capacity payment would collect the shortfall between the revenue from selling at the marginal energy price and the total generation cost.[14] A refinement would be to include a variable capacity payment equal to the Value of Lost Load times the Loss of Load Probability with the energy price, to give a better measure of the scarcity value of reliable power,[15] leaving less to be collected from the other element of the two-part tariff. If the owner (state or private) were confident that over the investment cycle the Power Selling Price (marginal energy price plus variable capacity charge plus ancillary service costs) would recover the full costs, then the fixed

[14] This would be similar to the Bulk Supply Tariff of the English CEGB under state ownership.
[15] As was the case in the England and Wales Electricity Pool from 1990-2001.

capacity payment could be set at zero, allowing dividends to bear the risk of variable gross profits. If not, and if the demand for access were sufficiently inelastic, varying the transmission plus fixed capacity shortfall element would still allow efficient marginal pricing without distorting demand much, and would stabilise annual revenues, allowing higher debt finance.

The other part of efficient pricing would be to signal future prices, so that as excess capacity falls, so the variable energy price would rise so that the time-weighted average (i.e. the base-load forward contract) is equal to the base-load LRMC. Given the difficulty of predicting future demand and the fact that the cost of a shortage is far higher than the costs of an equal surplus, there will be periods of under-pricing (relative to LRMC) that will need to be balanced by periods of apparent over-pricing. A franchise monopoly should be encouraged to publish a forward price curve, and to offer long-term contracts (or contracts-for-differences) linked to that curve.

The spot energy price should be computed from the dispatch or unit commitment algorithm (allowing for constraints, ideally via nodal pricing as in PJM or New Zealand) and various kinds of contracts can then be offered on that spot price.[16] With vertical integration and a franchise monopoly there is a strong case for this pseudo-market to be subject to external market scrutiny to ensure that the calculations are verified and contracts properly cleared. If the relevant institutions to monitor and regulate the industry are sufficiently credible and trust-worthy, then independent power producers (IPPs) can enter the market and offer competing contracts to the end-users (including distribution companies). Failing that, a single buyer could be established to sign PPAs with IPPs and with the incumbent's generators, either as a long-term solution or as a transition to a competitive wholesale market.

Conclusions

Even the best regulated franchise electricity companies may deliver prices that are out of line with the efficient price, and this mismatch can be particularly severe if the industry is under reform, and/or when new investment is required. Excess capacity with book value accounting can lead to under-pricing, particularly if the WACC is not continuously adjusted to maintain the correct real rate of interest as inflation varies. Book values can depart from the correct value (the ODV) of the assets, although the impact on the cost of employing those assets is partly offset by nominal interest rates that exceed the real rate of interest by the rate of inflation. However, the more serious problem is that state-owned companies are reluctant to charge a commercial risk-adjusted real rate of interest on their assets, which, for very capital-intensive industries like electricity, leads to systemic under-pricing and a serious problem of opening the market to private investors.

Even financing SOEs by bond issue results in under-pricing, as state-owned franchises have implicit sovereign guarantees, and the state is typically reluctant to insist on a suitable

[16] Several liberalised electricity wholesale markets such as England and Wales and PJM adopted such an approach for computing the wholesale price, usually using bids rather marginal costs, although some Latin American markets required audited marginal cost bids. Thus Chile's despatch centres compute short and long-run marginal costs according to a formula (Newbery, 1999: Vignolo, 2000).

dividend return (which should depend on the gearing of the company). The most important reform of state-owned enterprises is to raise the required (and achieved) *real* rate of return to the marginal rate of return in the private sector, which is likely to be substantially above the rate of growth of the economy. If that is done, then the real rate of return to electricity companies should exceed the rate of growth of demand, and, once prices have been adjusted to the LRMC, allow a substantial degree of self-financing of investment, reducing the pressure for over-hasty restructuring and privatisation, while making it possible to involve private sector finance. A good test of whether prices are set at an adequate level is whether IPPs are willing to invest to sell into the wholesale electricity market in periods when investment is needed.

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