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Rationale for restructuring and regulation of a 'low priced' public utility: a case study of Eskom in South Africa

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Abstract

Eskom in South Africa provides an interesting case study to test the prevailing orthodoxy on electricity market reform. Eskom is the seventh largest electricity utility in the world. It is a publicly owned, vertically integrated monopoly, with the cheapest prices globally. Is there any rationale for independent regulation of Eskom or for embarking on a reform of the South African electricity market?

The paper gives a snapshot view that Eskom's current prices can be misleading. Low current prices do not necessarily mean that Eskom is operationally or allocatively efficient. Eskom's electricity prices are low primarily because Eskom did not have to invest in new generation plant for many years. Much of the debt it incurred during the large expansion programme in the 1970s and 1980s has been amortized. Eskom's short-run marginal costs are also low, primarily because its primary energy costs are well below international levels. Lower costs have also been maintained though improved labour productivity and technical performance—although contradictory trends are observed which make it hard to benchmark Eskom's operational efficiency against international best practice.

Eskom's historical investment record has been poor. The analysis in this paper reveals the significant misallocation of capital by Eskom's decision-makers and the massively wasteful overcapacity in the generation plant. The impact on prices has been profound.

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Eskom has not always had competitive prices. In real terms, they were nearly double the current levels in the late 1970s and 1980s and will have to rise in the future as capacity runs out and new investments have to be made in generation. Furthermore, the long-term price trend reveals that current electricity prices, in real terms, are no lower than they were in the early 1950s and early 1970s. The question then has to be asked, whether Eskom has been able to harvest the potential efficiency gains that should have been possible from the application of new technology?

These insights provoke the question of whether Eskom has operated within a governance and regulatory environment that has provided sufficient incentives for improved performance. Low price, publicly owned utilities may not appear to require independent regulation or restructuring. However, this case study of Eskom in South Africa demonstrates the importance of a thorough historical understanding of utility performance in order to expose possible inefficiencies. The test for new and re-regulated electricity markets is whether they can encourage efficient investment and operational behaviour to secure electricity supply at the lowest possible cost.

Introduction

Eskom, the publicly owned, vertically integrated electricity utility in South Africa, ranks seventh globally in terms of electricity sales. It also generates amongst the lowest priced electricity in the world. But does the fact that Eskom's prices and costs are low mean that it is also among the most efficient of electricity utilities? And, if its prices and costs are low, what is the rationale for restructuring or re-regulating Eskom?

In this paper, we describe and analyse the electricity industry in South Africa in terms of its historical investment and operational record. We examine the main elements that contribute to the cost of electricity and how these have changed over time. We conclude by arguing the case for restructuring and re-regulation in order to maximize efficiency gains in the future.

Eskom's historical background

The electricity industry in South Africa was spurred by the development of diamond and gold mining. Kimberly, the site of the first large diamond mine, had electric street lights in 1882 (before London) and during the 1890s most of South Africa's major cities were reticulated. A number of independent power companies were established. For example, the VFP (Victoria Falls Power Company Ltd) was registered in 1906 with the vision of harnessing the hydro-electric potential of the Victoria Falls to meet the demand for electricity around Johannesburg and Southern Rhodesia (Zimbabwe). Technical and financial constraints resulted in the company focusing on coal-fired power stations, which in time became the dominant electricity generator in the region.

By the early 1920s, the Government of South Africa was concerned about the lack of standardization in the power industry and the need to expand capacity to support the electrification of the railways and accelerated industrialization. London-based consultants, Merz and McLellan, were commissioned to examine the 'general question of electricity supply' in South Africa. They recommended the need to have a central controlling authority to oversee and coordinate the development of the electricity industry. The government responded with the Electricity Act of 1922, which made the provision for the establishment of the publicly owned ESCOM (Electricity Supply Commission). ESCOM's primary goal was to establish new electricity undertakings in cooperation with the existing generators to ensure a cheap and abundant supply of electricity (Steyn 2001). At the same time the ECB (Electricity Control Board) was formed to issue licences and regulate electricity prices of ESCOM and private undertakings. Municipalities were not obliged to apply for licences. However, if municipalities wished to build new generating capacity, they had to seek the permission of the Provincial Administrators who, in turn, had to consult ESCOM. The consequence was that ESCOM began to build or finance most new power stations. It took over the VFP and Transvaal Power Company in 1948. Today it accounts for the bulk of the generating capacity in South Africa (Steyn 1994 and 2001, Eberhard 2003).

ESCOM sought to reap economies of scale and built larger and larger coal-fired stations as South Africa has only modest hydro-electricity and gas resources. Coal, on the other hand, is abundant and is mined at low cost. Following the oil price shocks of the 1970s, diesel and oil-fired generators of municipalities were uncompetitive and they began to rely more and more on ESCOM. The national high-voltage transmission grid was also interconnected at this time. Annual growth in peak demand between 1972 and 1982 ranged between 6% and 16%. ESCOM engineers and planners were concerned that there would be power shortages and even ordered more power stations to be built. Their power forecasting methods relied on extending past growth trends into the future and also on the optimistic economic growth rate. The consequence was an overestimation of demand, over-building of generation plant, and large price increases. Disquiet among stakeholders led to government appointing the De Villiers Commission in 1983. The Commission was critical of ESCOM's governance, management, forecasting methods, investment decisions, and accounting (Eberhard 2003).

ESCOM underwent major organizational and institutional changes in 1985 following the implementation of the Commission's recommendations. New Electricity and Eskom Acts were passed in 1987. ESCOM was renamed as 'Eskom' and was reconfigured with a new two-tier governance structure modelled broadly on the German corporate governance system. A full-time executive management board now reported to an Electricity Council comprising representatives of major electricity consumers, municipal distributors, and government representatives, all appointed by the Minister of Minerals and Energy. The drafters of the new Electricity Act, who included members of

ESCOM's legal department, inserted a clause that exempted Eskom from the need to have a licence issued by the Electricity Control Board and thus from having its prices regulated. Effectively, the Act relied on the consumer-dominated Electricity Council to control prices subject to government approval. The new management also had to re-establish Eskom's credibility and reputation with the government and its customers (Eberhard 2003).

In the period following 1987, Eskom's management and operations were increasingly subject to commercial imperatives. The Capital Development Fund was abolished and Eskom's old fund accounting system was replaced with standard business accounting conventions. The principle of operating at 'neither a profit nor loss' was replaced by the need to 'provide the system by which the electricity needs of the consumer may be satisfied in the most cost-effective manner, subject to resource constraints and the national interest' (Eskom 1987). A number of initiatives were taken to deal with the excess generation capacity. Eskom postponed the construction of some power plants, increased the interval between the service dates of units, and mothballed and decommissioned old and inefficient power plants. No new power stations have been ordered by Eskom since 1985, although the plant ordered at that time has been commissioned later at rescheduled dates.

In the 1990s, further changes were fuelled by the democratic revolution that marked the end of the apartheid era in South Africa. A massive electrification programme was initiated and the proportion of the population with access to electricity increased from one-third to over two-thirds. A National Electrification Forum, comprising all interested stakeholders, recommended the rationalization of the distribution sector (too many local authority utilities are inefficient and cash-strapped). The Forum also recommended the conversion of the Electricity Control Board into a new NER (National Electricity Regulator) with powers to regulate the entire industry. The Electricity Act was amended and the NER was established in 1995.

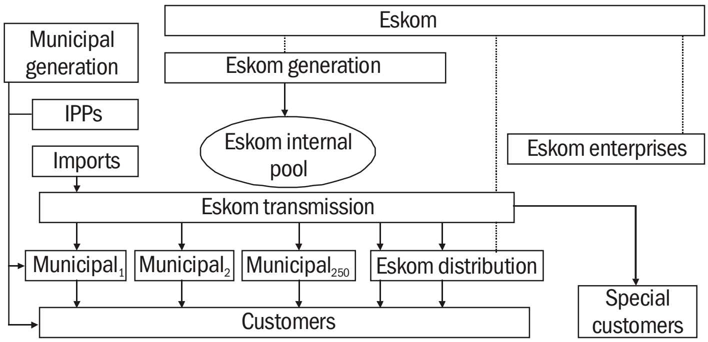
The early redistributive policies of the new South African government embodied in its election manifesto (the Reconstruction and Development Programme) were soon accompanied by a self-imposed structural adjustment programme (named Growth, Employment and Redistribution Policy). The new emphasis was increasingly on macro-economic stability, fiscal conservatism, and the progressive restructuring and privatization of state-owned enterprises. An *Energy Policy Paper* was published in 1998. It set out a vision for the electricity industry which included the possibility of unbundling, competition, customer choice, and private participation in the electricity industry. In 2000, the Department of Public Enterprises published *A Policy Framework: an accelerated agenda towards the restructuring of state owned enterprises*, which further emphasized a 'managed liberalization' process.

The Eskom Conversion Bill of 2001 replaced the old Eskom Act of 1987 with subsequent amendments. Eskom was converted into a public company (named Eskom Holdings Ltd) with its share capital held by the state. It now paid taxes and dividends. A memorandum to the Bill described its purpose as bringing about more efficiency and competitiveness in the running of Eskom, exposing Eskom to global trends and ensuring that Eskom is run in terms of a protocol on cooperative governance. One consequence of the corporatization of Eskom is that the capital subsidies for the connection of low-income consumers are no longer funded internally by Eskom, but derive from fiscal allocations to a national electrification fund.

The government has stated its intention to unbundle transmission and guarantee third-party access, to sell 30% of Eskom's generation, and to introduce competition through a multi-market (comprising bilateral contracts and a voluntary spot market), with a choice for large customers (>100 GWh per annum). However, to date there has been no unbundling or privatization and there is no competition in the electricity supply industry in South Africa. It is still not clear whether there are strong enough political drivers for reform that will cause initial policy pronouncement to be translated into pragmatic reform actions.

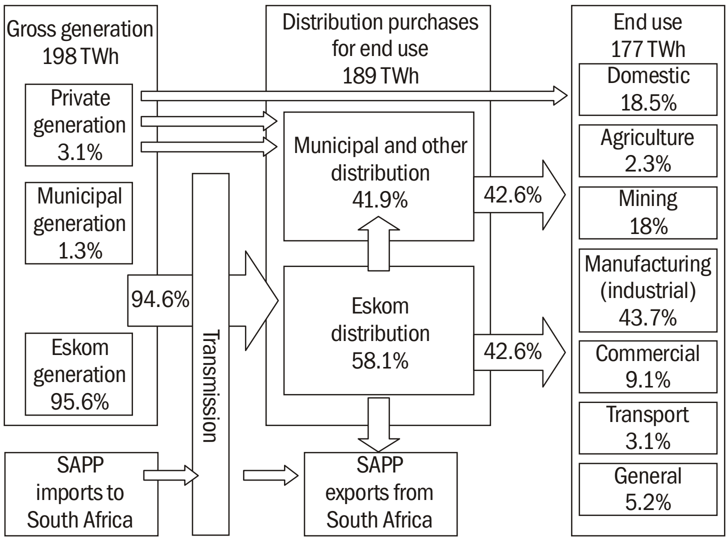
The existing South African electricity supply industry

The South African ESI (electricity supply industry) (Figure 1) remains dominated by Eskom. It supplies about 96% of South Africa's electricity requirements (Figure 2) which equals more than half of the electricity generated on the African continent. Eskom owns and controls the high voltage transmission grid and supplies about 60% of electricity directly to customers. The remainder of electricity distribution is undertaken by about 177 local authorities. They buy bulk-supplies of electricity from



IPPs – independent power producers

Figure 1 Structure of the electricity supply industry in South Africa



SAPP – South African power pool

Figure 2 Energy flows in the Electricity Supply Industry in South Africa 2000

Source NER (2000)

Eskom, with some also generating small amounts in their areas of jurisdiction. A few industries have private generation facilities for their own use.

Ninety-one per cent of electricity is generated from coal, nuclear energy accounts for 6.5%, while bagasse, hydro, and emergency gas turbines make up the remaining 2.5%. Total generating capacity in South Africa in 2000 was 43.1 GW (gigawatt) of which Eskom owns 39.9 GW most of which is available for generating electricity for sale. Some capacity was mothballed and the total net operating capacity amounted to 35.3 GW. Peak demand on the system was 32 GW in 2003. Eskom has 24 power stations, of which 10 large coal-fired stations dominate—most of them comprise six 600-MW units and are situated on coal mines in the north-east of South Africa. South Africa's only nuclear station is at Koeberg, 30 kilometres north of Cape Town, and is owned and operated by Eskom. There is modest hydro-capacity generation on the Orange River, located on two dams, and there are two pumped storage schemes which play a critical role in meeting peak demand, as well as in system balancing and control (Eskom 2001, NER 2001).

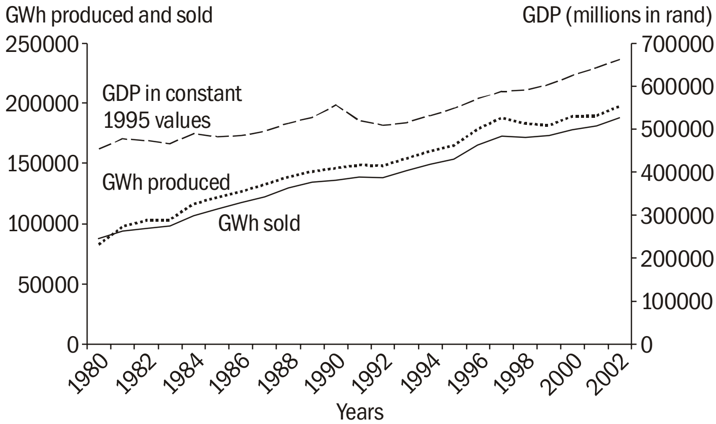
Eskom makes most of its profits from the sale of electricity to its large mining and industrial customers and in bulk sales to municipalities. These three customer categories account for 82% of its revenue and 89% of its electricity sales. The average selling price in 2000 to industrial customers was 1.6 cents/kWh[2] and for residential customers was 3.7 cents/kWh (Eskom 2000).

Tariffs for rural and low-income residential customers are cross-subsidized from industrial tariffs and surpluses earned on sales to municipalities. The large municipalities, in turn, make an additional profit from reselling Eskom electricity, which enable them to subsidize property rates and to finance other municipal services. However, many of the smaller municipalities face debt, non-payment by a substantial proportion of their low-income consumers, inefficient operations, and lack of technical and managerial capacity.

Electricity demand growth in South Africa is primarily a function of the GDP (gross domestic product) plus new investments in energy-intensive mining and minerals beneficiation projects (such as aluminium and steel) (Figure 3). Electricity sales slowed down in 1991, 1992, and 1998 when the economic growth declined. Generally, sales in electricity consumption increased at an average rate of 4.9% from 1980 to 1990 and 2.7% from 1991 to 2001.

In broad terms, the ESI has supported economic development through the provision of low-cost and reliable supply of electricity. In recent years, it has also contributed to improving social equity by increasing access and subsidizing supplies to the poor. However, there are a number of problems and challenges

[2] Assuming an exchange rate of 1 dollar = 7.5 rand



GDP – gross domestic product

Figure 3 Production and sale of electricity by Eskom and South Africa's gross domestic product

Sources *Eskom Annual Reports* (1980–2002); *Statistical Yearbooks* (1985–96) and IMF (2003, pp. 876; 2000, pp. 890)

that are driving changes. These include the need to improve the performance of the distribution industry; the need to create a competitive environment for new investment in generation capacity; and to unlock the economic value in the industry, including widening of economic participation, particularly to previously disenfranchized South Africans. But whether these are strong enough political drivers for change remains to be seen.

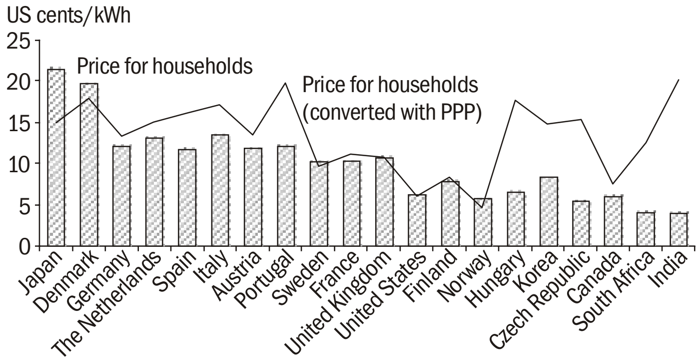
Cost, price, and income trends

International comparison of electricity prices

A comparison of Eskom's electricity prices with available data from selected countries shows Eskom's household and industrial tariffs to be among the cheapest in the world (Figures 4 and 5).

Do Eskom's prices cover costs?

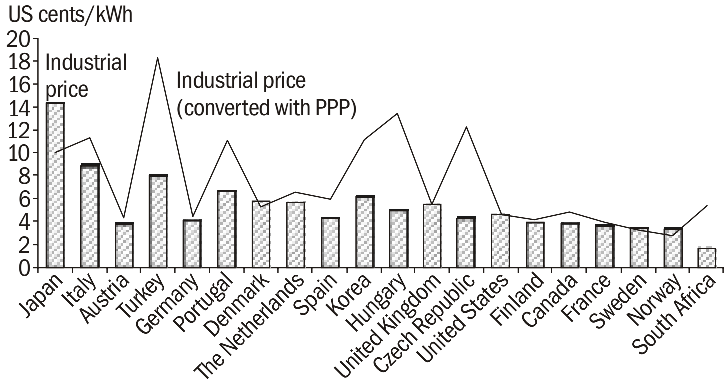
Eskom's costs have generally been covered by income. Figures 6 and 7 show that prices have been set at levels that have provided sufficient income to cover operating expenses, capital charges, as well as a positive return on capital and equity. Net operating income (before interest and tax) increased substantially in the early 1980s as prices increased to fund new investment. Net income (after interest and tax) has cycled in a band between 2 billion rand and 4 billion rand (in real 2000 values). Eskom has earned



PPP – purchasing power parity

Figure 4 Household prices in selected countries in 2000

Sources IEA (2001) and EIA (2003)



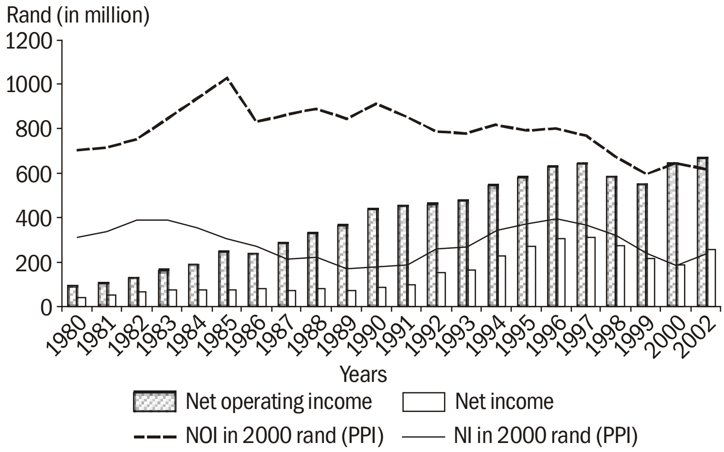
PPP – purchasing power parity

Figure 5 Industrial prices in selected countries in 2000

Sources IEA (2001) and EIA (2003)

a before tax return on assets of between 8%–12% over the past two decades.

Eskom's net income is a function not only of its cost structure but also of the prices that it is able to charge. Eskom has been an effective monopoly and has proposed annual price increases that cover its costs. The regulatory regime has been fairly light (indeed between 1987 and 1995, Eskom was not subject to any formal regulation). In broad terms, price increases had to be politically acceptable. As its interest burden declined in the 1990s, Eskom offered a voluntary pricing compact with the



PPI – producer price index

Figure 6 Net operating income and net income from 1980 to 2001

Source *Eskom Annual Reports* (1980–2001)

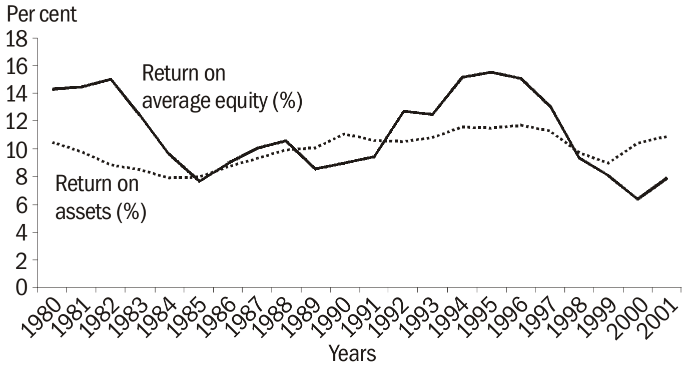


Figure 7 Eskom's return on assets and return on equity from 1980 to 2001

Source *Eskom Annual Reports* (1980–2001)

government to reduce the price of electricity in real terms by about a fifth. Eskom, of its own accord, told the government that it was prepared to lower the price of electricity by about a fifth over a number of years. However, in the past three years, Eskom has motivated for price increases above inflation, arguing that it has to fund new investment. The past three years have also seen the first serious attempt to regulate Eskom and the NER has determined price increases at lower levels than requested by Eskom.

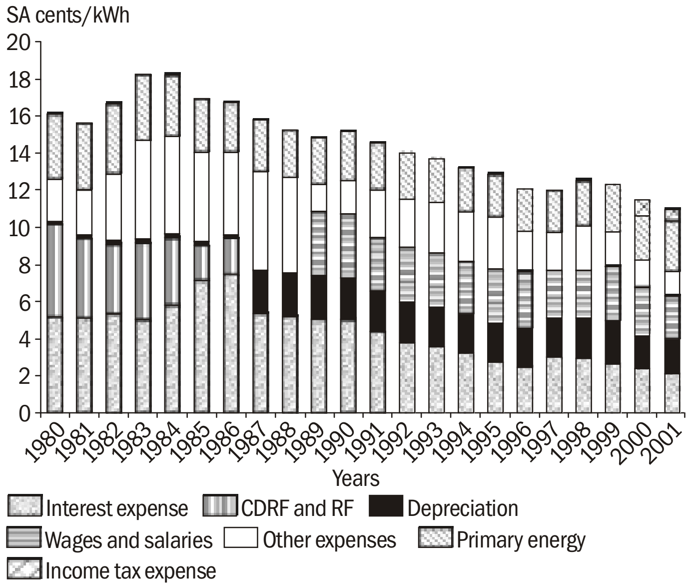


Figure 8 Eskom's electricity cost components (real year 2000 values)
Sources *Eskom Annual Reports* (1980–2001) and *Statistical Yearbooks* (1985–2001)

Eskom's cost components

Eskom's costs comprise primary energy, salaries, operating and maintenance, depreciation, interest charges, and income tax. Figure 8 shows the proportional contribution of each cost component in the electricity price from 1980 to 2001 expressed in real (2000) values.[3] Generally, from 1980 to 1986 more than half of Eskom's costs were capital related.[4] Subsequently, there was a decline in capital-related costs that has brought about a significant reduction in the price of electricity (about 3.2% per annum on average).

Analysis of factors contributing to Eskom's low cost

Primary energy (coal)

Most of Eskom's electricity is produced from coal. Primary energy comprises just over a quarter of the cost of each unit of electricity. The price Eskom pays for coal is low compared to international coal prices. This is primarily because power sta-

[3] 1US cent = 7.5 SA cents

[4] Includes interest expenditures, (capital development and reserve fund) and RF (redemption fund).

Table 1 Steam and coal prices for electricity generation in dollar/tonne

Country	*Prices in 2000*
France	35.50
Germany	42.40
South Africa*	5.87
United Kingdom	44.40
United States	24.50

Sources IEA (2002, 2001, 2000), EIA (2003), and *DME (2003)

tions are built adjacent to coal mines producing low cost, low calorific-value coal,[5] supplied on favourable long-term contracts.

International comparison of coal prices

Table 1 shows that the price of coal in South Africa is far below that in many industrialized countries.

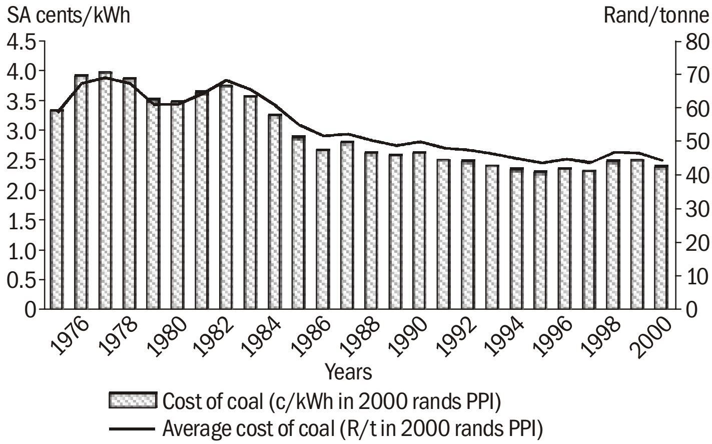
Eskom's coal supply contracts

Of Eskom's 10 major coal-fired stations, nine have long-term coal contracts.[6] Six of these long-term coal contracts are 'cost-plus' and three are 'fixed price'. In the cost-plus contracts, Eskom and the coal supplier jointly provided capital for the establishment of the colliery. Eskom pays all the costs of operation of the colliery and the supplier is paid a net income by Eskom on the basis of a ROI (return on the capital invested) by the coal supplier in the colliery. The ROI is divided into two components: a fixed and variable portion. The fixed portion is a set ROI, payable irrespective of tonnage of coal supplied, and the variable portion is based on the tonnage supplied to Eskom. The ROI is generally escalated for half the duration of the contract and is typically between 15% and 25%. In the fixed-price contract, coal is supplied at a predetermined price—a base price which is escalated by means of an agreed escalation formula. There are no early termination provisions in the contracts.

Coal prices increased in 1981 and 1982 when Eskom experienced supply problems with its contracted collieries and had to buy coal from other producers (Eskom 1981, 1982) (Figure 9).

[5] For example, the Lethabo power station was designed to burn bituminous coal with a caloric value of 16 MJ/kg, which is low world standards (Eskom 1992).

[6] The tenth large coal-fired power station, Majuba, operates at a variable output on a small and medium-term coal contract.



PPI – producer price index

Figure 9 Eskom coal costs (real 2000 values)

Source *Eskom Annual Reports* (1980–2000) and *Statistical Yearbooks* (1985–96)

Prices declined after 1982 as a result of more favourable coal contracts that were concluded when a new plant was commissioned. After 1995 prices were levelled off, but they are now increasing primarily as a result of the increased utilization of Eskom's more expensive plant (which requires coal to be transported by rail).

Interest expenditure

The contribution of interest charges to the electricity price has fallen over the years. In 1986, interest costs contributed to about 44% of the electricity price and it declined to 17% in 2001 (Figure 10).

Reduction in capital expenditure and debt

Eskom funded its capital expansion through commercial debt by issuing bonds on domestic and international markets. From 1980 to 1985 the real net interest-bearing debt increased at an average of 12% per annum. Interest costs halved between 1985 and 2001 and the electricity price decreased by 27% in real terms over the same period (Figure 11).

Debt-to-equity ratio (or gearing ratio) and interest cover ratio

The reduction in debt and interest payments is also revealed in Eskom's declining debt-to-equity ratios and in the increase in

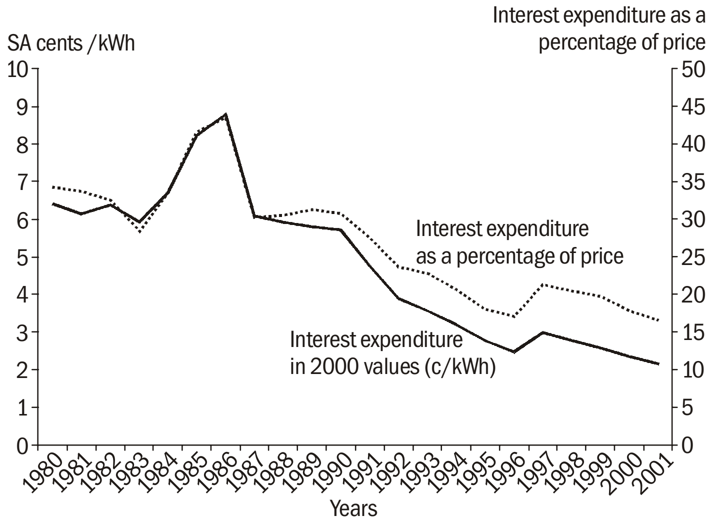
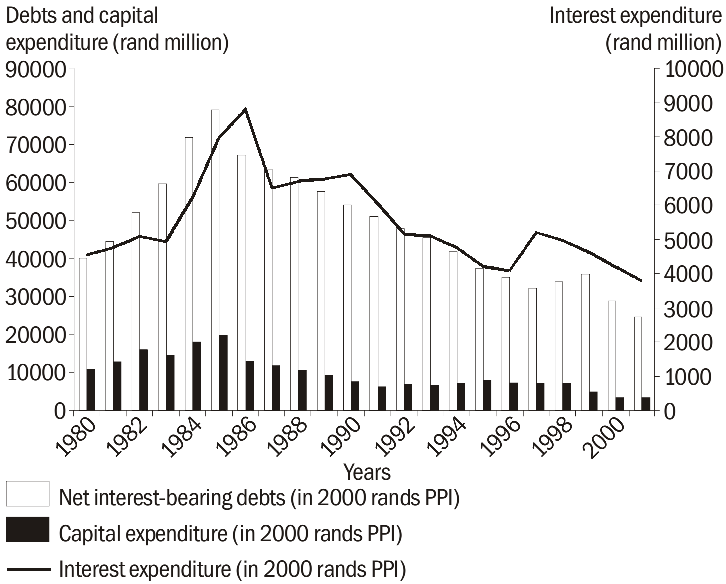


Figure 10 Interest costs per kWh (real 2000 values)
Source *Eskom Annual Reports* (1980–2001)



PPI – producer price index
Figure 11 Net interest-bearing debt, capital expenditure, and interest costs (real 2000 values)
Source *Eskom Annual Reports* (1980–2001)

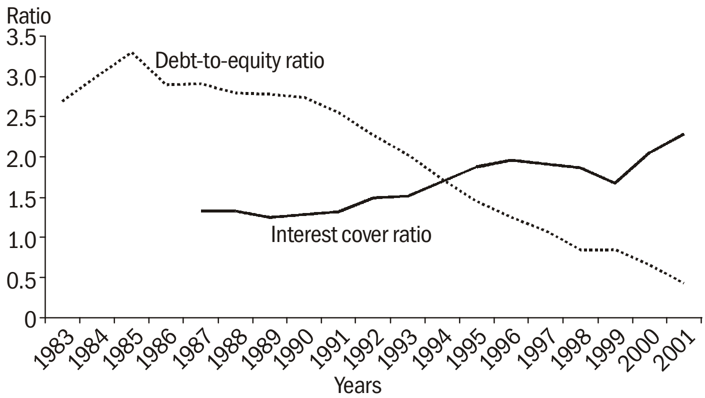


Figure 12 Debt-to-equity ratio and interest cover ratio
Source *Eskom Annual Reports* (1983–2001)

the interest cover ratio (Figure 12). Debt-to-equity ratios can be ascertained by dividing long-term liabilities by shareholders equity or total liabilities by shareholders' equity depending on the accounting policies adopted. The interest cover ratio is a ratio that shows the company's ability to honour its interest charges as they become due. It is ascertained by dividing earnings before interest and taxes (operating profit) by interest expenses. Eskom's debt-to-equity ratio increased to 3.3 in 1985 and has since then declined steadily to about 0.4 in 2003. As would be expected, Eskom's interest rate cover had improved as its debt has declined.

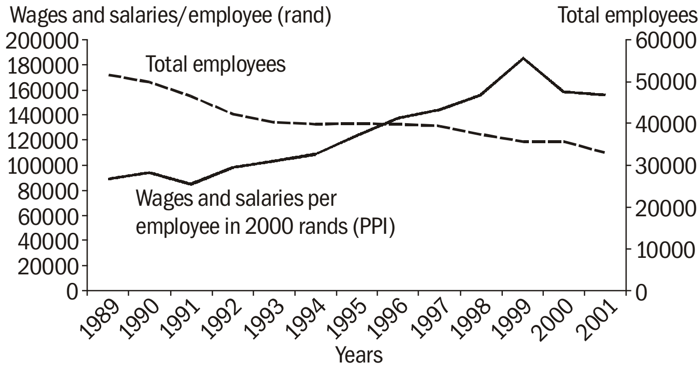
Employment costs

The number of Eskom employees has declined from over 66 000 in 1985, to 46 600 in 1991, to 32 800 in 2000. Figure 13 shows that the average salary per employee has increased substantially in real terms, partially off-setting the potential cost reductions that were possible from these productivity improvements.

The proportional contribution of salary costs to the electricity price has declined, as shown in Figure 14.

Other factors contributing to Eskom's low prices

There are a number of other reasons why Eskom's prices and costs may be low. Eskom was initially established as a non-profit-making entity, and between 1923 and 2000 was liable for neither tax nor dividend payments. Eskom's electricity prices also do not fully include externalities like pollution costs. While



PPI – producer price index
Figure 13 Wages and salaries and total employees
Source *Eskom Annual Reports* (1980–2001)

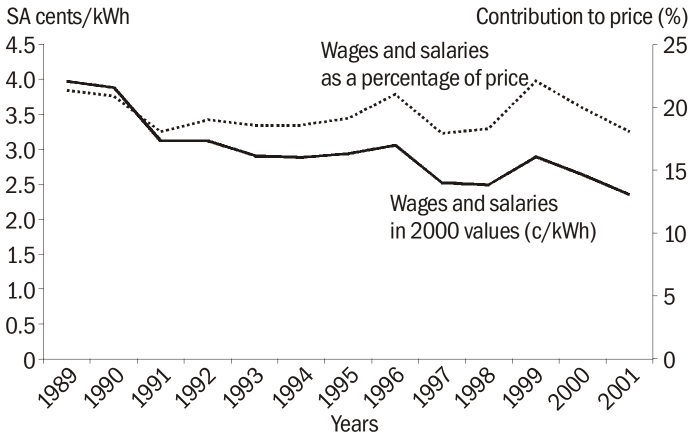


Figure 14 Proportional contribution of wages and salaries to electricity price
Source *Eskom Annual Reports* (1980–2001)

electrostatic precipitators and bag filters reduce particulate emissions, Eskom power stations do not have flue gas desulphurization which is common in coal-fired plants in industrialized countries. Finally, Eskom’s operational and technical performance may also contribute to low costs. This is examined in more detail below.

Technical performance

Generation load factor

The generation load factor is the ratio between the energy that a power plant has produced during a period considered and the

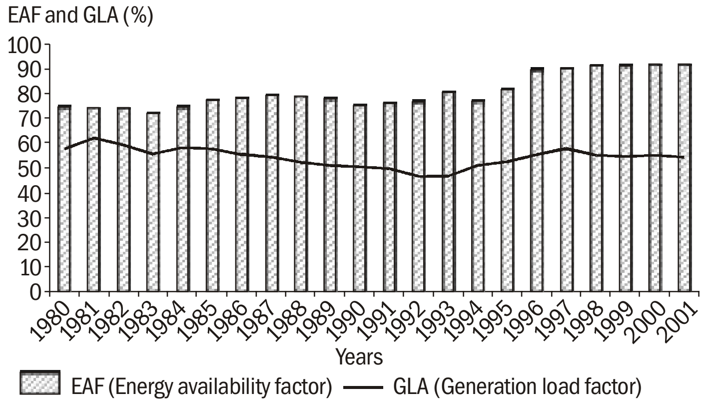


Figure 15 Average energy availability factor and generation load factor of Eskom
Sources *Eskom Annual Reports* (1980–2001) and *Statistical Yearbooks* (1985–96)

energy that it could have produced at maximum capacity under continuous operation during the same period. Generation load factors are appropriate for the determination of operational performances of power plants that are exclusively meant for base load, but perhaps give a misleading picture when a peaking plant is also included. Eskom's average generation load factor has not improved over the years, partly because of overcapacity and also because of the increased 'peakiness' of the power demand profile.

The EAF (energy availability factor) is the percentage of maximum energy generation that a plant is capable of supplying to the electrical grid, limited only by planned and unplanned outages. EAF improved substantially in the early 1990s and remains at internationally comparable levels (Figure 15).

Overall thermal efficiency

Overall thermal efficiency 'measures the success with which the heat energy in the fuel is converted to electrical energy in the generator' (Eskom 1990). Thermal efficiency can be improved by increasing steam pressures and temperatures. An increase in thermal efficiency helps the utility to reduce the amount of coal required to produce 1-kWh of electricity, which would subsequently reduce electricity price.

Figure 16 shows Eskom's thermal efficiency improved substantially during the 1980s as a new, larger, and more modern generation plant was commissioned. The challenge in the 1990s was to maintain this performance (though not always successfully).

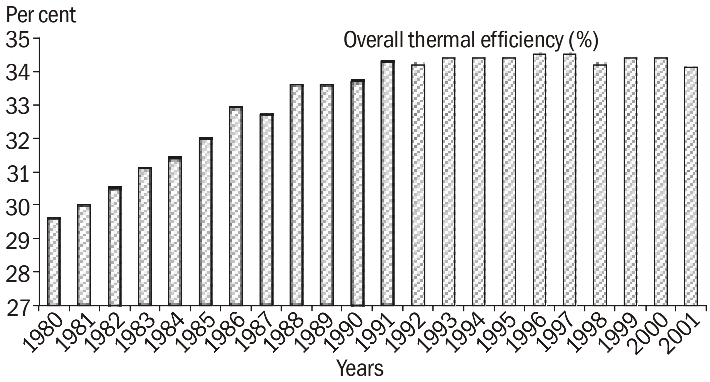


Figure 16 Overall thermal efficiency (1980–2001)
Sources *Eskom Annual* Reports and *Statistical Yearbooks* (various years)

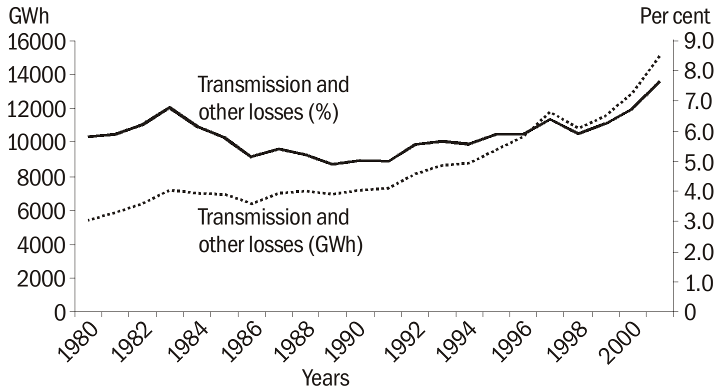


Figure 17 Transmission and distribution losses*
*Transmission and distribution losses have been calculated from the difference between electricity generated and sent out, and electricity sold.
Sources *Eskom Annual Reports* (1980–2001) and *Statistical Yearbooks* (1985–1996)

Transmission and distribution losses

Transmission and distribution losses result when electricity sold is lesser in comparison to electricity generated and transmitted (Eskom 2001), including both technical and non-technical losses due to theft and non-payment. Figure 17 shows that transmission and distribution losses have been increasing particularly from the early 1990s to 2001. This was a time when Eskom was directly involved in large-scale electrification of households which in turn led to an increase in its distribution losses.

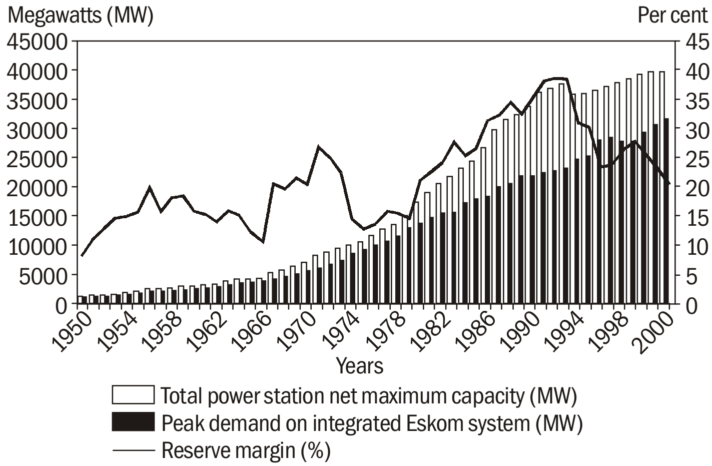


Figure 18 Net maximum capacity, peak demand, and reserve margin
Sources *Eskom Annual Reports* (1980–2002) and *Statistical Yearbooks* (1985–96)

Investment performance

Investment decisions in the power sector involve high risks. New generation capacity is capital-intensive and poor investment decisions could mean that power needs are not met. Poor decisions could also result in expensive overcapacity. Investment or allocative efficiencies can have a profound impact on costs.

Capacity expansion

Figure 18 shows the growth in generation capacity compared to power demand and the percentage of reserve margin. There appears to be cyclical investment cycles of increased overcapacity followed by periods when investment slows down. The sustained growth in new capacity between 1974 and 1993 is striking, with the reserve margin reaching a peak at 38%.

Figure 19 illustrates excess capacities over and above a required 15% of reserve margin. Despite cancellation and postponement of new generation orders after the mid-1980s, excess capacity continued to grow and reached a peak of nearly 9000 MW in 1993. The annual growth in peak demand is also shown.

Investment and prices

Figure 20 again reveals the significant price hikes that were as sociated with the investment cycle, particularly the huge expansion of generation capacity in the late 1970s and 1980s. Figure 20

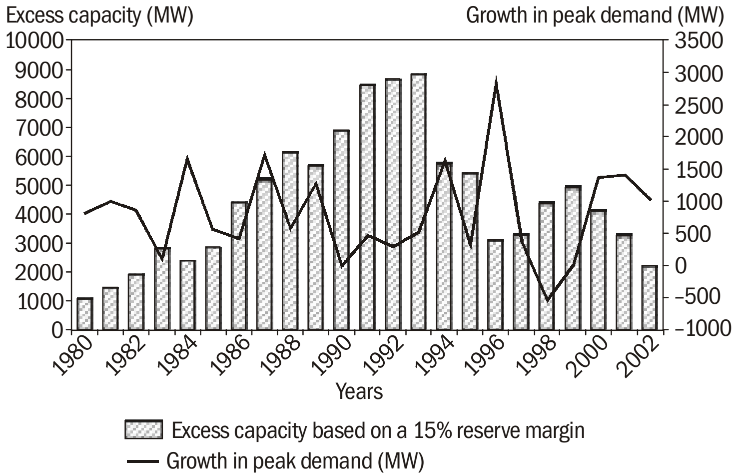


Figure 19 Excess capacities and growth in peak demand
Sources *Eskom Annual Reports* and *Statistical Yearbooks* (various years)

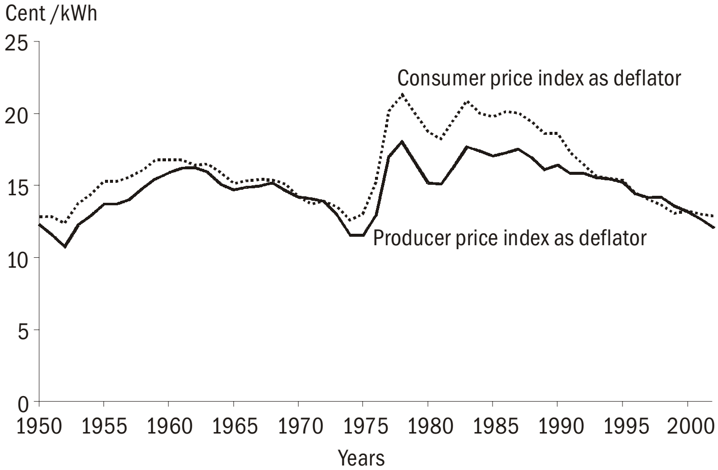


Figure 20 Long-term price performance
Source Eskom's presentation to NER (2003)

also demonstrates that Eskom's electricity price today is no lower, in real terms, than it was in the early 1950s and 1970s. Evidently the economies of scale, and improved thermal efficiencies, associated with new generation plant, have not worked their way through to a long-term decline in the electricity price.

Conclusion

Eskom's electricity prices are clearly low by international standards. The above analysis has shown that prices are low primarily because Eskom has not had to invest in new generation plant for many years. Much of the debt it incurred during the large expansion programme in the 1970s and 1980s has been amortized. Its debt-to-equity ratio has been reduced substantially. Accordingly, the contribution of finance and interest charges to the cost of producing electricity are very low.

Eskom's short-run marginal costs are also low, primarily because its primary energy costs are well below international levels. Eskom power stations are situated adjacent to low-cost coal mines. Further reasons for Eskom's low costs are the absence of flue gas desulphurization and the fact that, in previous years, Eskom was not liable to pay tax or dividends.

Labour productivity (number of employees per electricity output) has substantially improved since the mid-1980s, although higher salary levels have largely cancelled out these gains. Technical performance has improved in a number of areas. New generation plant enabled improved thermal efficiencies—that is less coal is required to produce a unit of electricity. Plant availability improved in the early 1990s, but has declined in recent years. Technical and non-technical losses on the distribution system have worsened through the 1990s.

Eskom's historical investment record has been poor and the above analysis indicates the extent of misallocation of capital resources that resulted in massively wasteful overcapacity in generation plants. The impact on prices has been profound as a result of this. Eskom has not always had competitive prices. In real terms, they were nearly double the current levels in the 1970s and 1980s, and will have to rise in the future as capacity runs out and new investments have to be made in generation.

The long-term price trend reveals that current electricity prices, in real terms, are at the same level as the early 1950s and early 1970s. The question then has to be asked whether Eskom has been able to harvest the potential efficiency gains that should have been possible from the application of new technology?

The implication of the above analysis is that a snapshot view of Eskom's current low prices does not provide any real indication of its efficiency. However, an examination of historical trends reveals important insights. It is clear that there have been major investment inefficiencies. It is also clear that over the long term, we have not seen consistent downward pressure on operational costs that would have been expected from the employment of new technology and improved productive efficiencies.

These insights provoke the question whether Eskom has operated within a governance and regulatory environment that has provided sufficient incentives for improved performance. When these questions are raised within policy debates regarding the possible restructuring of Eskom, the rejoinder is often: 'if it ain't broke don't fix it!' However our analysis has shown that there are serious shortcomings in the way investment risks have been managed, with profound long-term cost and price implications. In a monopolistic model, risks and costs of poor investment decision are simply passed on to consumers. Steyn (2001) has demonstrated that there are a number of inherent characteristics of monopoly institutions that make this quite likely. There is a sound basis for serious consideration of a new institutional model for the electricity industry in South Africa: one that will provide a more appropriate apportioning of investment risk. Indeed, work has begun on designing a competitive electricity market for South Africa (Eberhard 2001).

The effectiveness of regulation also has to be questioned. Although Eskom's marginal costs are low by international standards, we have shown that low coal costs are one of the primary reasons. There is little hard evidence on how Eskom's productive efficiencies compare internationally. Regulation of Eskom has historically been quite light. However, in recent years the NER has been instituting a more rigorous and transparent regulatory methodology and there is some indication that there is room for further efficiency improvements.

Low price, publicly owned utilities may not appear to require independent regulation or restructuring. This case study of Eskom in South Africa demonstrates the importance of a thorough historical understanding of utility performance in order to expose possible inefficiencies. The test for new, re-regulated electricity markets is whether they can encourage efficient investment behaviour and operational performance to secure electricity supply at the lowest possible cost.

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Pricing and cost recovery of urban services: issues in the context of decentralized urban governance in India

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Abstract

Developing countries usually do not have a pricing policy for urban basic amenities such as water supply, sanitation, and solid waste disposal. These are normally considered to be public goods to be supplied free of cost. Generally, a token cost is collected which in no way reflects the actual cost of provision. India is no exception in this regard. However, the decentralization initiative as adopted in the 74th Amendment Act, 1992 has devolved major responsibilities to the urban local bodies. As a consequence, it has become imperative in the present scenario for them to look for alternative mode of resources to undertake additional responsibilities. The objective of the present paper in this context is to analyse the pricing pattern of basic amenities—water supply, sewerage, and solid waste management. Moreover, it also looks at the extent of cost recovery in urban basic services for the three cities of Ahmedabad, Chennai, and Pune and whether there have been any significant changes particularly after the decentralization initiative. The cities have been selected based on their organizational and institutional structure for the provision of basic amenities.

Introduction

Financing of infrastructure, in general, and basic urban services, in particular, is different from financing of other industrial activities because of its characteristic features of non-excludability, externality, huge investment requirements, and so on. Similarly, the general economic theoretical explanation of pricing of commodities does not hold good for urban services. The commodities that are marketable are generally priced on the basis of the equality between its level of demand and supply. The equality of the marginal cost of producing a commodity and the marginal revenue generated out of it determines the equilibrium price. Such a clear-cut pricing mechanism cannot be adopted for urban services because of its features of non-excludability and externality.

In applying the marginal cost-pricing rule for public services like water supply, sewerage, solid waste disposal, and street lighting, three aspects are taken into consideration.

1 the level of consumption of the service;
2 the access or connection to the service; and
3 the opportunity to use or to connect to the service.

The first one involves the consideration of only the short-term marginal costs, that is the additional inputs required to produce the added service unit. The second one involves two types of costs: first, it is the infrastructure cost to connect a customer to the arteries of the distribution (or collection) network including any recurrent cost of maintaining the service; second, it is the cost that the public authority will have to incur to make readily available, whatever, the customer demands. The third one involves the cost to make available the opportunity to use a particular service at a particular location as per the consumers' preference pattern. Thus, the marginal-pricing rule needs consideration of all these features of the additional costs that are linked to it (Bahl and Linn 1992).

Most of the developing countries, particularly in South Asia, lack any pricing policy for these services and generally charge a token price, which does not in any way relate to the cost of supply and distribution. Moreover, some of these services are the minimum basic subsistence required for survival and are to be provided irrespective of any payments being made against them. However, such a philosophy is in the process of change because of shortage of funds. Thus, it has become imperative to look for a proper pricing mechanism for urban services to make the development in this sector self-sustainable.

In this context, the present paper is an attempt to look into some of the issues that arise in the pricing of basic urban services in India. To address the issues in a systematic fashion in the Indian context, the study has selected three cities (Ahmedabad, Chennai, and Pune) with varied structures of provision of urban services, particularly water supply, sewerage, and solid waste disposal. The second section provides details of the pricing pattern of these services in these three cities and the changes in pricing pattern, if any, during the post-74th Amendment era. The third section is devoted to the trend and pattern of revenue and expenditure structure of water supply, sewerage, and solid waste disposal in these three cities. The objective is to analyse the extent of costs of these facilities that are being recovered from within the sector. In other words, assess how much the sector is self-financing. The fourth and the final sections provide a detailed account of the collection efficiency of various water- and sewerage-related taxes and charges in these three cities and changes in it, if any, over the decade of 1990s, particularly during the later years.

Pricing pattern of basic services

An attempt has been made to discuss the pricing pattern of the water supply and sanitation-related services in the three cities of Ahmedabad, Chennai, and Pune. It would also analyse whether any significant move has been made in this regard during the 1990s, particularly after the adoption of the decentralization initiative during 1993. Although it is too early to analyse the impact of decentralization, at least some insight could be obtained from this analysis. Tables 1, 2, and 3 provide the rates of taxes and charges levied on water and sewerage and changes in them over time in Ahmedabad, Chennai, and Pune, respectively. Both the AMC (Ahmedabad Municipal Corporation) and CMWSSB (Chennai Metropolitan Water Supply and Sewerage Board) levy water and sewerage taxes besides charges. On the other hand, in addition to water and sewerage taxes and charges, the PMC (Pune Municipal Corporation) also levies water benefit tax and sewerage benefit tax.[1] These taxes are being levied by the PMC

[1] Additional taxes computed as a percentage of water and sewerage taxes levied over and above these.

Table 1 Rates of water- and sanitation-related taxes and charges levied in Pune

Tax/charge	*1990/91–1991/92*		*1994/95–1995/96*		*Since 1998*		*Percentage increase*	
							First half of 1990s	*Second half of 1990s*
Water tax*	15% of ARV (for ARV> Rs 2500)		17.5% of ARV (for ARV> Rs 3000)		25% of ARV (for ARV> Rs 3000)		16.67	42.86
	Minimum of Rs 365 (for Re 1<ARV<Rs 2499)		Minimum of Rs 525 (for Re 1<ARV<Rs 2999)		Minimum of Rs 750 (for Re 1<ARV<Rs 2999)		43.84	42.86
Water charges **	Domestic	Non-domestic	Domestic	Non-domestic	Domestic	Non-domestic	Domestic/ Non-domestic	Domestic/ Non-domestic
(Rs per kilolitre)	1.30	6.00	2.00	10.00	2.00	10.00	53.85/66.66	No increase
	Cantonment areas		Cantonment areas		Cantonment areas			
(Rs per kilolitre)	1.3	6.9	2.5	10	2.5	10	92.30/44.93	No increase
	Relocated slums		Relocated slums		Relocated slums			
	Not applicable		Rs 175 per annum		Rs 250 per annum		Not applicable	42.86
Water benefit tax #	1% of ARV		2% of ARV		2% of ARV		100.00	No increase
Conservancy tax	11% of ARV		11% of ARV		13% of ARV		No increase	18.18
Sewerage benefit tax #	3% of ARV		4% of ARV		4% of ARV		33.33	No increase

* Generally levied on unmetered connections in the older part of the city; ** If meters are faulty, the amount of water flow is estimated by ferule size and hence charges are estimated; # Levied since 1991/92

ARV – annual rental value

Source Water and Sanitation Department of the Pune Municipal Corporation

Table 2 Rates of water- and sanitation-related taxes and charges in Ahmedabad

Tax/charge	*1990/91–1991/92*		*1994/95–1995/96*		*Since 1998*		*Percentage increase* *First half of 1990s*	*Second half of 1990s*
Water tax								
Residential properties								
Area < 100 km^2	11% of ARV		13% of ARV		15% of ARV		18.18	15.38
100 < Area < 150 km^2	11% of ARV		13% of ARV		17% of ARV		18.18	30.77
150 < Area < 200 km^2	11% of ARV		13% of ARV		20% of ARV		18.18	53.85
Area >200 km^2 (other than bungalows)	11% of ARV		13% of ARV		22% of ARV		18.18	69.23
Area >200 km^2 (only bungalows)	11% of ARV		13% of ARV		25% of ARV		18.18	92.31
Non-Residential Properties								
Area < 10 km^2	11% of ARV		13% of ARV		15% of ARV		18.18	15.38
10 < Area < 15 km^2	11% of ARV		13% of ARV		17% of ARV		18.18	30.77
15 < Area < 20 km^2	11% of ARV		13% of ARV		20% of ARV		18.18	53.85
Area > 20 km^2	11% of ARV		13% of ARV		22% of ARV		18.18	69.23
Water charges	Domestic	Non-domestic	Domestic	Non-domestic	Domestic	Non-domestic	Domestic/	Domestic/
(Rs per kilolitre)	1.50	4	1.50	4	3	8	Non-domestic no increase	Non-domestic 100
Conservancy tax								
Residential properties								
Annual assessment	–	–	15% of ARV		18% of ARV		–	20
Minimum monthly rates								
General (Rs)	–	–	6		10		–	66.67
For hutments (Rs)	–	–	2		5		–	150
Non-residential properties								
Annual assessment	–	–	26% of ARV		30% of ARV		–	15.38
Minimum monthly rates (Rs)	–	–	6		15		–	150
Conservancy charges (Rs)								
Common house (per unit)	–	–	250		400		–	60
Low rise flats	–	–	150		250		–	66.67
Commercial buildings (variation across area)	–	–	500 to 1200		750 to 2000		–	50 to around 67
Multi-story building (up to 3 stories with variation across area)	–	–	10 000		15 000 to 35 000		–	
Hotels (variation across status)	–	–	2500 to 25 000		4000 to 40 000		–	

ARV – annual rental value
Source Water and Sanitation Department of the Ahmedabad Municipal Corporation

Table 3 Rates of water- and sewerage-related taxes and charges levied in Chennai

					Percentage increase	
Tax/charge	*1990/91–1991/92*	*1994/95– 1995/96*	*Since 1998*	*Since 1998*	*First half of 1990s*	*Second half of 1990s*
Water charges						
Domestic			Consumption/month	Rate (Rs/kilolitre)		
Metered	Re 1 and Rs 2 per kilolitre	Rs 2 to 4 per kilolitre	Up to 10 kilolitre	2.5	100	50
			10 kilolitre to 15 kilolitre	10		
			15 kilolitre to 25 kilolitre	15		
			more than 25 kilolitre	25		
Unmetered	Rs 12 per month	Rs 30 per month	Rs 50 per month		150	66.67
Domestic (non-residential)			Consumption/month	Rate (Rs/kilolitre)		
Metered	Rs 3, 4, and 5 per kilolitre (minimum Rs 60 per month)	Rs 10 per kilolitre (minimum Rs 250 per month)	Less than 500 kilolitre	25	233.33–316.66	150–300
			More than 500 kilolitre	40		
Unmetered	Rs 60 per month	Rs 250 per month	Rs 400 per month		316.66	60
Commercial			New category created			
Metered	Rs 3, 4, and 5 per kilolitre (minimum Rs 60 per month)	Rs 10 per kilolitre (minimum Rs 125 per month)		108.33%–233.33%	Not applicable	
Unmetered	Rs 60 per month	Rs 125 per month				
Industrial			New category created		Not applicable	
Metered	Rs 7 and 10 per kilolitre (min. Rs 60 and 75 per month)	Rs 25 per kilolitre (minimum Rs 250 per month)		150%–316%	Not applicable	
Unmetered	Rs 60 and 75 per month	Rs 250 per month			233.33%–316.66%	Not applicable
Partially commercial	Category did not exist	Category did not exist	Consumption/month	Rate (Rs/kilolitre)		
Metered			up to 10 kilolitre	5		
			10 kilolitre –15 kilolitre	10	Not applicable	Not applicable

			more than 15 kilolitre	15		
Unmetered			Rs 150 per month			
Institutional	Category did not exist	Category did not exist				
Metered			Rs 20 per kilolitre (for entire consumption)	Not applicable	Not applicable	
Unmetered			Rs 200 per month			
Municipal bulk supply	Category did not exist	Category did not exist	Rs 15 per kilolitre (for entire consumption)			
Bulk consumer	Rs 10 per kilolitre (minimum Rs 75 per month)	Rs 20 per kilolitre (minimum Rs 250 per month)	Rs 25 per kilolitre (minimum Rs 330 per month)	233.33	32	
Public authority						
Metered	Rs 3 per kilolitre (minimum Rs 60 per month)	Rs 10 per kilolitre (minimum Rs 125 per month)	Rs 15 per kilolitre (minimum Rs 165 per month)	108.33	32	
Unmetered	Category did not exist	Rs 125 per month	Rs 165 per month		Not applicable	32
Sewerage charges						
Domestic	20% of water charges	20% of water supply charges	25% of water ss charges	No increase	25	
Domestic (Non-residential)	20% of water charges	20% of water ss charges	25% of water ss charges	No increase	25	
Commercial	20% of water charges	20% of water ss charges	New category created		No increase	Not applicable
Industrial	20% of water charges	20% of water ss charges	New category created		No increase	Not applicable
Partially commercial	Category did not exist	Category did not exist	25% of water ss charges	Not applicable	Not applicable	
Institutional	Category did not exist	Category did not exist	25% of water ss charges	Not applicable	Not applicable	
Municipal bulk supply	Category did not exist	Category did not exist	25% of water ss charges	Not applicable	Not applicable	
Bulk consumer	20% of water charges	20% of water ss charges	25% of water ss charges	No increase	25	
Public authority	20% of water charges	20% of water ss charges	25% of water ss charges	No increase	25	

ss – sanitation and sewerage

since 1991/92. While the taxes are generally levied on the ARV (annual rental value) of properties, charges are levied on volumetric measures in case of metered connections. If the connections are unmetered or the meters are non-functioning, water charges are estimated on the basis of amount of water flow based on the ferule size.

A reasonable number of domestic water connections are metered in Chennai and Pune, while it is not the case in Ahmedabad where generally it is the non-domestic connections that are metered. It is mostly the industrial and commercial connections that are metered. As a result, charges account for a major share of revenue of this sector in Chennai and Pune. It is the water and conservancy tax on the other hand that contributes significantly to its revenue in Ahmedabad. However, in recent years there has been an attempt from various spheres to make the sector self-sufficient. Moreover, an attempt to make the sector commercially viable has further instigated these measures. As a consequence, the new water and sewerage connections for domestic purposes, are also connected to meters to make cost recovery more efficient.

Both the corporations of Ahmedabad and Pune as well as the CMWSSB, in addition to these taxes and charges, also levy one-time connection charges. These connection charges generally vary with the size of the pipe and the purpose for which it is being utilized. Generally, the tendency has been to keep the connection charges higher for non-domestic connections. The connection charges varied between a minimum of 500 rupees for half-inch connection to a maximum of 10 000 rupees for connections varying between three and four inches in Pune. The connection charges had not been revised in Pune since 1988. The major deficiency that could be observed with the water and sewerage connection charges is that either these charges remain very low or these have not been revised for a long time. It was only in 1997/98 that the connection charges were revised in Ahmedabad after almost a decade. However, the recent revision in connection charges was substantial in Ahmedabad. Provision was made for variations between metered and unmetered connections. The charges were in many cases implemented at various stages of the work required for providing individual connections. It varied between 500 rupees for a half-inch connection to a maximum of 25 000 rupees for a four-inch branch pipeline connection. In addition, drainage connection charges varied from a minimum of 400 rupees for domestic purposes to 750 rupees for commercial purposes to 50 000 rupees for 5-star hotels.

The situation seems to be comparatively better in Chennai, the revision of the water- and sewerage-related tariff rates was done more frequently almost once in two to three years. The increase in the water- and sewerage-related tariff rates has been significantly pronounced during the second half of the 1990s than during the first half. In Ahmedabad, while the water tax increased on average by about 18%–20% during the first half of the decade, it varied between 15% and 90% during the later half for various categories (Table 2). The water charge, which did not increase during the first half, increased by 100% during the later half. However, the situation in Pune tells a different story altogether. While there was significant increase during the first half, it was not that pronounced during the second half. Only water tax and water charges in the relocated slums have shown a significant increase in Pune during the later half of the 1990s. Conservancy tax also registered an increase during the later half (Table 1). This can be attributed to the separate budget that was being maintained for water supply and sewerage since early 1990s. As a consequence, instant measures were adopted to make the sector self-sustaining. However, in most of the cases, the tariff rates are in no way related to the cost of water supply and/or collection or treatment of waste water in any of the three cities. No demand-side management for water or cost estimates for its provision has been done to make the sector more efficient, cost-effective and responsive. Even the revisions are done on the basis of a proportionate increase over the existing ones without taking into account the increase in the treatment cost and the cost of supply. The cost of treatment obviously increases due to increase in the cost of raw materials required for it.

It is common that the pricing is quite objectively done and hence the cost of recovery in water supply and sewerage services is comparatively better where these are looked after by the state-level water utility boards. This is, however, often considered to be an argument against decentralization. Thus, the CMWSSB seems to be comparatively better because of its lesser accountability towards people, as this is an administratively autonomous body than an elected one. Water tariffs in Chennai have shown a similar trend for both residential and non-residential purposes during the first half of the decade (Table 3). However, for most of the water-related charges, the increase has been more pronounced during the first half. On the other hand, sewerage charges that are collected as a fixed proportion of water charges were revised only during the second half. The CMWSSB came up with certain new categories during the mid-1990s making the system more complex and less transparent further increasing the possibility of evasion.

An overview of the pricing trend and pattern in Ahmedabad, Chennai, and Pune reveals that the system of pricing seems to have improved over the years during the past decade. Moreover, it is comparatively better than the general gloomy picture normally revealed for the sector in urban India. However, it has often been argued that the low cost recovery has been mainly due to irrational and non-transparent tariff structure. As a consequence, there is a need to look into the fact whether an increase in tariff has brought about an improvement in collection efficiency and hence capacity to generate revenue by the sector. The low cost of recovery in the sector has, however, made the sector vulnerable and risk-prone. Neither do lenders have much interest in lending in this sector nor are the private operators comfortable enough to invest in this sector. Keeping in mind the increase in demand for these services in future, it is worth mentioning that the sector needs to have a demand-based management approach on the basis of cost estimates of the services provided by the municipal bodies or utility boards.

Trend and growth of revenue and expenditure

The structure of the provision of these services in Ahmedabad, Chennai, and Pune has been discussed earlier. In this context, it needs mentioning that the water supply, sewerage, and solid waste disposal are completely looked after by the municipal corporations in Ahmedabad and Pune. Both maintenance and capital investments in these sectors are within the jurisdiction of municipal authorities. Solid waste disposal in Chennai remains within the purview of the CMC (Chennai Municipal Corporation). Water supply and sewerage is, however, maintained by the CMWSSB. The planning for capital investments in this sector has been the responsibility of the Board since 1978.

The analysis in this context would be done individually with respect to the water supply, sewerage, and solid waste disposal in Ahmedabad, Chennai, and Pune. The analysis would be taken up from three angles. Firstly, it would look into the extent of revenue expenditure that the sector in itself is capable of undertaking from its own revenue sources. This would be done by going into the detail of the revenue expenditure made in these sectors and revenues generated out of these sectors per head of population during the decade of 1990s.[2] Moreover, this would be done by taking into account the share of revenue and expenditure that these sectors contribute towards the total revenue and total revenue expenditure of the authority.[3] Secondly, it would try and look into the extent of cost recovered in these sectors through the collection–demand ratio of the various taxes and charges levied on these services. Moreover, it would also try to look at the initiatives, if any, towards the revision of the rates of various taxes and charges after the decentralization and whether it has added to increase in the extent of cost-recovery in the sector.[4] Finally, the study would evaluate the performance of the sector in itself, that is what share of its total expenses is made on various heads within the sector. The objective is to get the idea of the extent of expenditure on repair and maintenance and establishment expenses made in water supply and sanitation sector in these three cities. The whole analysis will, however, remain confined to the decade of the 1990s.

This is a fact that the costs of the basic urban services are not recovered and thus the services are in a poor condition. However, it is often explained otherwise that it is due to the poor condition of the basic amenities that the beneficiaries are reluctant to pay for these services. The sector is basically trapped in a low-level disequilibrium situation. In other words, the poor situation of services leads to the low level of cost recovery making the level of investments further low, which, in turn, makes the condition of urban services poorer. An overall analysis of the water supply and sanitation sector as a whole reveals that the extent of cost recovery in this sector has been very low. Table 4 reveals that the cost recoveries against water supply and sewerage have been quite low in Ahmedabad. The situation worsens

[2] Data for this part of the analysis are derived from the budget documents of the municipal corporations of Ahmedabad and Pune for various years. The annual accounts of the CMWSSB have provided for it in the case of Chennai.

[3] In bringing out the share of revenue and expenditure of this sector to the total revenue and expenditure, the revenue and expenditure accounts of the CMC and the CMWSSB have been merged.

[4] Decentralization has least to offer for Chennai as water and sewerage are looked after by the CMWSSB, a board directly under the jurisdiction of the state government.

Table 4 Revenue and expenditure scenario: water supply and sanitation sector of the Ahmedabad Municipal Corporation

Revenue and expenditure	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/2000*
Per capita income from WS and sewerage (Rs)	45.94	55.12	48.42	62.68	93.79	103.62	141.61	141.27	208.79	229.34
Per capita expenditure on WS and sewerage (Rs)	89.49	102.31	107.88	131.64	134.18	143.47	162.54	183.95	260.48	310.29
Per capita income from water supply (Rs)	15.70	17.27	18.25	26.34	39.27	42.85	59.40	61.14	99.87	106.91
Per capita expenditure on water supply (Rs)	61.98	72.59	66.75	81.97	80.10	89.76	97.79	118.53	150.18	175.59
Per capita income from sewerage (Rs)	30.23	37.84	30.17	36.34	54.52	60.77	82.21	80.13	108.92	122.43
Per capita expenditure on sewerage (Rs)	27.51	29.72	41.14	49.67	54.08	53.71	64.75	65.42	110.30	134.70
Per capita income from SWD and sanitation (Rs)	0.12	0.13	0.15	0.16	0.16	0.18	0.18	0.46	0.47	1.29
Per capita expenditure on SWD and sanitation (Rs)	42.01	50.94	50.77	61.45	71.22	83.56	88.46	98.31	133.39	170.20
Per capita income from WS and sanitation sector (Rs)	46.06	55.25	48.56	62.84	93.95	103.80	141.79	141.73	209.26	230.63
Per capita expenditure on WS and sanitation sector (Rs)	131.50	153.25	158.65	193.09	205.40	227.03	251.00	282.26	393.87	480.49
Share of WS and sewerage revenue to TR (%)	8.84	9.28	7.33	8.73	10.28	9.36	11.92	11.18	15.15	10.28
Share of WS and sewerage expenditure to TRE (%)	15.95	17.20	16.25	17.91	16.96	15.57	16.46	16.93	21.14	17.00
Share of WS and sanitation sector revenue to TR (%)	8.86	9.30	7.35	8.75	10.30	9.38	11.94	11.22	15.18	10.34
Share of WS and sanitation sector expenditure to TRE (%)	23.44	25.77	23.90	26.27	25.96	24.64	25.42	25.98	31.97	26.32

WS – water supply; SWD – solid waste disposal; TR – total revenue; TRE – total revenue and expenditure

Source Budgets of the Ahmedabad Municipal Corporation further when the solid waste disposal is taken into account. In 1990/91, while water supply and sewerage contributed towards just 8.84% of the total revenue of the AMC, it accounted for almost 16% of the total revenue expenditure (Table 4). This is generally accounted for in the prevailing low level of tariffs. While the Asian countries' average tariff stands at 0.36 dollars per cubic metre, it is just 0.08 dollars per cubic metre in India, computed on the basis of the four metropolitan cities of Chennai, Delhi, Kolkata, and Mumbai (World Bank 2000). The average is likely to decrease substantially provided some of the small and medium towns are incorporated in the analysis.

Moreover, the situation further worsens when solid waste disposal is taken into account as this sector virtually contributes nothing towards the revenue of the AMC and accounts for almost 7.5% of the total revenue expenditure. This is mainly due to the fact that the solid waste disposal is labour-intensive and does not own much of its revenue source. In some of the cities, though there exists scavenging fees for collection of solid wastes and cleansing of the streets, most cities do not levy any tax or charges for this purpose. This is normally funded out of the revenues of the other sectors. The toxic, industrial, and commercial wastes are also seldom taxed. Recently, several cities adopted initiatives towards segregating different categories of wastes. Moreover, user pay, abuser pay, and polluter pay principles have been implemented. The financial requirements to provide adequate collection and disposal facilities for solid wastes tend to rise quite rapidly with the increase in urbanization in the developing countries. As a result, sources of revenue must be identified to recover the costs of collection and disposal. Often it is argued that the nature of solid wastes in Indian cities and particularly, the collection mechanism, does not permit the wastes to be used for compost and incineration.

The share of total expenditure on the water supply and sanitation sector as a whole in 1990/91 amounts to 23.44% (water supply and sewerage is 15.95%), while the share of it in the total revenue is almost equal to that of what is generated by water supply and sewerage (Table 4). However, the situation does not show much of an improvement during the later years even after the decentralization initiative as adopted through the 74th Constitution Amendment Act. The shares of the revenue of the water supply and sanitation sector as a whole to total revenue of the AMC have shown marginal increase during the later years. In real terms, throughout the period of study the water supply sector suffered huge deficits. The deficit on account of water supply is mainly due to higher dependence on water tax as a source of revenue rather than user-charges based on volumetric measures which in the true sense reveal the actual cost of consumption. This is mainly due to the fact that a significant share of the domestic connections is unmetered. During the initial years though the sewerage sector has shown marginal surplus, in 1992/93 and 1993/94 it has shown some amount of deficit on this account. However, the later years have shown surplus in the revenue account. It is because of the huge deficit suffered by the AMC on account of water supply that the per capita expenditure on water supply and sewerage has been almost double the amount of the per capita receipt from the sector (Table 4). This difference has, however, reduced during the later years (particularly since 1994/95) when measures were adopted towards financial strengthening of the municipal corporation.

SWM (solid waste management) seems to be the worst sufferer in this regard. The per capita revenue from SWM has almost remained constant, while the revenue expenditure has substantially increased over the period of study. The per capita revenue has increased from 0.12 rupee in 1990/91 to 0.46 rupee in 1997/98. On the other hand, the per capita revenue expenditure on it has increased from 42.01 rupees to 98.31 rupees during the same period. It is because of the low revenue collection of solid waste disposal that water supply and sanitation sector as a whole suffers a huge deficit. However, the deficits during the later years have shown a decline after the initiatives towards levy of user-charges and tariff revision adopted by the AMC since 1994/95. It can be argued that with proper initiative to recover costs of these services, it is possible to make the sector self-sustaining and bring it out of the vicious circle. However, it would need coordination between the elected representatives and appointed officials. Moreover, state-level support would be a prerequisite in this regard. To improve the extent of cost recovery, the World Bank has recommended reduction in price distortions by setting tariffs on a cost-reflective basis, at least for those who can pay. However, this would need tremendous institutional, regulatory, and policy support.

Almost a similar picture is revealed by the pattern of revenue and expenditure for water supply and sanitation sector of the PMC. The PMC maintains a separate budget for water supply and sewerage activities. As in the case of the AMC, water supply is more prone to deficits for PMC as well. However, the gap between the per capita income from water supply and per capita expenditure on it has been far less than the one suffered by the AMC. This could perhaps be accounted to the large-scale metering of the domestic water connections in Pune municipal area. Moreover, since the mid-1990s, water and sanitation taxes were also levied on the consumers in the relocated areas and slums. These were further revised in 1998/99. Over 50% of the total domestic connections are metered in Pune unlike other larger cities. In most of the larger cities, water is being priced based on taxes that are normally a proportion of the ARV as most of the domestic connections are unmetered. Water charges on the basis of volumetric measures are collected only from the industrial and commercial consumers. Unlike the case of AMC, during most of the years under study (between 1990/91 and 1999/2000), the PMC enjoyed a surplus on account of sewerage except for 1993/94 and 1996/97. These years show marginal deficits (Table 5). However, the deficit on account of water could more than offset the surplus in the sewerage sector leading to an overall deficit for C-Budget (water supply and sewerage budget of PMC) except in 1990/91 and 1996/97 (Table 5). The deficit suffered has reduced, particularly, due to the recent revision of the water rates.

Solid waste disposal as a municipal activity is the worst performer, virtually contributing nothing to the revenues of the PMC and accounting for a substantial share of the revenue expenditure. As a result, solid waste collection, transportation, and disposal activities have been contracted out to private operators in many cities including some smaller ones to make it more efficient and cost-effective. However, the revenue collection from solid waste disposal by the PMC has shown some significant increase over the years. Nevertheless, the per capita expenditure has shown remarkable increase making the situation even worse during the later years of the 1990s. The per capita expenditure on solid waste disposal has shown an increase from 52.86 rupees in 1990/91 to 119.04 rupees in 1997/98 (Table 5). It is largely due to the poor revenues from solid waste disposal that water supply and sanitation sector as a whole suffered huge deficit.

Often it is argued that due to the lack of a standardized system of financial information maintenance, the inter-municipality or inter-municipal corporation comparison of the finances is of less

Table 5 Revenue and expenditure scenario of water supply and sanitation sector of the Pune Municipal Corporation

Revenue and expenditure	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/2000*
Per capita income from WS and sewerage (Rs)	128.22	137.01	172.71	188.97	213.39	341.17	336.31	336.57	616.16	606.41
Per capita expenditure on WS and sewerage (Rs)	119.66	167.00	178.24	195.63	213.39	313.78	377.92	406.73	616.11	611.22
Per capita income from water supply (Rs)	78.16	82.64	99.76	112.58	122.90	144.89	129.21	152.45	228.31	256.70
Per capita expenditure on water supply (Rs)	84.84	133.92	142.89	143.78	186.89	254.51	306.42	338.98	381.25	520.82
Per capita income from sewerage (Rs)	45.49	45.37	50.71	48.63	55.92	62.34	66.02	71.25	79.10	92.48
Per capita expenditure on sewerage (Rs)	34.82	33.02	35.29	50.95	52.90	59.27	69.18	67.75	95.56	90.39
Per capita income from SWD and sanitation (Rs)	5.64	6.27	6.54	7.19	7.71	8.66	9.41	9.97	15.05	17.77
Per capita expenditure on SWD and sanitation (Rs)	52.86	59.70	67.35	75.93	87.02	100.24	109.47	119.04	127.29	129.54
Per capita income from WS and sanitation (Rs)	133.86	143.28	179.25	196.16	221.10	349.83	345.72	346.54	631.21	624.18
Per capita expenditure on WS and sanitation (Rs)	172.52	226.70	245.59	271.56	300.41	414.02	487.38	525.77	743.40	740.76
Share of WS and sewerage revenue to TR (%)	22.93	21.49	21.69	22.66	21.96	25.06	21.35	20.56	27.04	25.85
Share of WS and sewerage expenditure to TRE (%)	24.77	31.00	28.04	27.45	26.86	32.70	37.06	35.42	43.68	33.24
Share of WS and sanitation sector revenue to TR (%)	23.94	22.47	22.52	23.52	22.76	25.70	21.95	21.17	27.70	26.60
Share of WS and sanitation sector expenditure to TRE (%)	35.72	42.08	38.64	38.11	37.82	43.14	47.80	45.79	52.70	40.29

WS – water supply; SWD – solid waste disposal; TR – total revenue; TRE – total revenue and expenditure

Source Budgets of the Pune Municipal Corporation relevance. This can be explained on the basis of the comparison of the finances of the water supply and sanitation sector of the two corporations of Ahmedabad and Pune. It might apparently seem that the share of revenues from the water supply and sewerage in the PMC stands at a much higher level than that of the AMC (Tables 4 and 5). However, in this context, it is worthwhile to mention that the water supply and sewerage have a separate budget in Pune and this budget receives a substantial amount of general-purpose grant specifically under this budget head. These are normally taken into account while computing the income from water supply and sewerage. Such general-purpose revenue grants for water and sewerage could not be separated out of the total general-purpose grants for the AMC and hence could not be accounted for under the income head of water and sewerage. This is due to the fact that general-purpose grants were devolved irrespective of any particular sector.

Solid waste disposal in the PMC has accounted for widening the disparity during the later years of the 1990s between the level of per capita expenditure and per capita revenue of the water supply and the sanitation sector as a whole. A comparative analysis of the growth of per capita income and expenditure of the water supply and sanitation sector of the AMC and the PMC shows that the measures adopted by the AMC has a positive impact. The ACGR (annual compound growth rate) between 1994/95 and 1997/98 in per capita revenue from water supply and sanitation for the AMC was higher in comparison to the per capita expenditure in the sector (Table 6). The income per capita from the PMC's water supply and sanitation sector has grown at a higher rate during the later period (1994/95 and 1997/98). However, the expenditure per capita on water supply and sanitation has grown at a much faster rate during the later years (1994/95 and 1997/98) making the situation even worse (Table 6). Thus, initiatives towards revised tariff policy might lead to an improvement in the finances of this sector as seen from the AMC's experience. A cost-reflective tariff policy also has implications for efficient utilization of services, efficient resource allocation, responsiveness on behalf of consumers, and generation of surplus for capital investments.

In Chennai, it is only the solid waste disposal that is within the jurisdiction of the CMC. Since 1978, the water supply and sewerage activities in the city are being looked after by the CMWSSB. Table 7 reveals a completely different story from the

Table 6 Water supply and sanitation: a comparison

Income and expenditure (Per capita figures in rupees)	*1990/91*	*1993/94*	*ACGR* (%)	*1994/95*	*1997/98*	*ACGR* (%)
Income: water supply and sanitation of PMC	133.86	196.16	10.02	221.10	346.54	11.89
Expenditure: water supply and sanitation of PMC	172.52	271.56	12.01	300.41	525.77	15.02
Income: water supply and sanitation of AMC	46.06	62.84	8.08	93.95	141.73	10.83
Expenditure: water supply and sanitation of AMC	131.5	193.09	10.08	205.40	282.26	8.27
Income: water supply and sanitation in Chennai*	104.98	239.31	22.88	205.67	379.79	16.57
Expenditure: water supply and sanitation in Chennai**	129.8	187.34	9.61	250.66	371.92	10.37

*includes income of the CMWSSB (Chennai Metro Water Supply and Sewerage Board), SWD (solid waste disposal), and sanitation of CMC (Chennai Municipal Corporation)

**includes expenditure of the CMWSSB and SWD and sanitation of CMC

ACGR – annual compound growth rate

Sources Based on the budget figures of the AMC (Ahmedabad Municipal Corporation), the PMC (Pune Municipal Corporation), the CMC, and annual accounts of the CMWSSB

one observed in the case of Ahmedabad and Pune. The water supply sector on its own enjoys a huge surplus in its revenue account because of the high cost of water supply recovery during most of the study years. The surplus on account of water supply has more than offset the deficit due to sewerage. It was only during 1991/92 that the per capita income of the CMWSSB (which reveals the income from water supply and sewerage) fell short of the per capita expenditure on it. The per capita revenue of the CMWSSB was 90.12 rupees in comparison to the per capita revenue expenditure amounting to about 108.04 rupees in 1991/92 (Table 7).

To get an idea of the share of water supply and sewerage in the total revenue from the Chennai Municipal Area and total expenditure on it, the revenue and expenditure of the CMWSSB and the CMC have been merged. During the study period, the water supply and sewerage sector contributed a major share to the combined revenues of the CMWSSB and the CMC than the share of expenditure made on these services except for 1991/92

Table 7 Revenue and expenditure scenario: Chennai Metropolitan Water Supply and Sewerage Board **

Revenue and expenditure	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/2000*
Per capita income from WS and sewerage (Rs)	104.87	90.12	116.72	239.12	205.44	223.43	258.52	378.98	357.06	379.18
Per capita expenditure on WS and sewerage	85.14	108.04	119.02	123.62	183.55	195.61	222.69	276.41	412.49	507.76
Per capita income from water supply	58.41	57.73	80.64	64.36	159.87	176.07	199.74	237.09	242.34	266.44
Per capita expenditure on water supply	26.59	34.25	38.12	39.58	58.02	61.58	69.77	86.39	126.78	120.83
Per capita income from sewerage	25.19	28.27	20.11	29.80	32.41	32.09	36.27	49.98	66.54	74.43
Per capita expenditure on sewerage	32.34	41.65	46.36	48.14	70.57	74.90	84.85	105.07	158.19	155.50
Per capita income from SWD and sanitation*	0.11	0.21	0.11	0.19	0.23	0.37	0.46	0.81	0.42	0.41
Per capita expenditure on SWD and sanitation*	44.66	48.56	56.74	63.72	67.11	73.40	79.88	95.51	108.24	112.93
Per capita income from WS and sanitation	104.98	90.33	116.83	239.31	205.67	223.80	258.99	379.79	357.49	379.59
Per capita expenditure on WS and sanitation	129.80	156.60	175.76	187.34	250.66	269.01	302.56	371.92	520.73	620.70
Share of WS and sewerage revenue to TR (%)	33.89	23.15	25.57	36.97	33.37	30.05	33.51	37.11	30.97	30.30
Share of WS and sewerage expenditure to TRE	26.57	28.51	28.30	26.56	32.03	31.18	32.23	34.03	32.01	34.74
Share of WS and sanitation sector revenue to TR	33.93	23.20	25.59	37.00	33.41	30.10	33.57	37.19	31.01	30.33
Share of WS and sanitation sector expenditure to TRE	40.51	41.33	41.79	40.25	43.75	42.88	43.80	45.79	40.41	42.47

WS – water supply; SWD – solid waste disposal; TR – total revenue; TRE – total revenue and expenditure

* Within the jurisdiction of the CMC (Chennai Municipal Corporation)

** To estimate the shares of various individual sectors in total revenue and expenditure, the revenue and expenditure of CMC and CMWSSB has been merged

Sources Budgets of the CMC and annual accounts of the CMWSSB and 1992/93 (Table 7). The surplus in water supply and sewerage can be attributed basically to the organizational structure for the provision of these services. The CMWSSB being a body under the state government is guided by a separate act and the provisions in the acts for the non-payment of water charges and taxes are more stringent than those generally found in the municipal acts. Moreover, even harsh measures to the extent of disconnecting water connections for late payments of dues are not very uncommon. Lastly, while generally the municipal corporations in larger cities are dependent on the taxes against these services, a substantial amount of revenue of the CMWSSB comes from water charges.

Studies have revealed that it is due to the non-standardization of the budgeting and accounting of the municipal bodies and utility boards, the inter-municipality or inter-city comparison of revenue and expenditure is often of less relevance. As a consequence, the comparability in this context should be subject to the fact that the water that is being provided to the slums through tankers has also contributed towards the income of the CMWSSB. Moreover, the income from public fountains also comes as charges to the metro water board. On the other hand, the revenues against services provided in slums come in the form of property taxes for the larger corporations. Moreover, the water provided out of the public fountains is in many cases not charged where these services are provided by the local bodies. The income as property taxes against services provided in slums does not form part of the revenue from water supply and sewerage leading to a decline in the share of revenue out of this sector.

In 1990/91, the share of charges in the income of the CMWSSB accounted for a substantial 61.08% of the total revenue, which increased to 79.24% in 1994/95, due to revision of rates in 1993/94. However, the share reduced to 62.71% in 1997/98 (Table 7). Contrarily for the AMC, charges accounted for a meagre share of just 19.62% in 1990/91. The share, however, increased to 22.61% in 1994/95, the year when the complete restructuring of the finances and the administration of the municipal corporation was attempted. Moreover, the share further improved to 26.20% in 1997/98 (Table 4). It was earlier mentioned that the AMC from a very poor financial condition of water and sanitation has reached a financially stronger position. As a consequence, the revenue out of this sector grew at a much higher rate than that of the expenditure during the later half of the 1990s (Table 6). However, the situation towards this end worsened over time for the PMC. A share as high as 68.08% of the sector to total revenue in 1990/91 reduced to a low of 45.98% in 1994/95 and further down to 36.37% in 1997/98 (Table 5). The high share of charges is perhaps due to the fact that during the initial years of the separation of C-Budget, it might have been provided with certain initial boost, which did not sustain. Perhaps this decline in the collection efficiency of water charges led to a more than offsetting growth of per capita expenditure on account of this sector than the per capita income during the later half of the decade.

Expenditure in water supply and sewerage: composition, trend, and pattern

This section would be an attempt to look at the inter-activity distribution of the total revenue expenditure made in water supply and the sanitation sector. However, before going into this detail the section would take up an analysis of the composition of total expenditure into revenue and capital. The objective in this regard is to have an idea of the extent of expenditure made in developing new assets within the cities vis-à-vis operation expenditure. One can notice that during the early years of the decade, significant shares of expenses have gone into revenue side. While it accounted for over two-thirds of the total expenditure (revenue plus capital) for Pune and Chennai, it accounted for over 90% of the total expenditure (Table 8). However, a positive feature has been the declining trend in the share of revenue expenditure to total expenditure for all the three municipal corporations.[5] While the decline has been significant for the AMC, it is moderate for Pune and Chennai corporations (Table 8). However, keeping in view the condition of the basic urban services in the larger cities in India, it is desirable to have the major share of expenditure in creating new assets in these services. Moreover, had expenditure in revenue account gone into maintenance of services, it would have largely taken care of the created assets. Further discussion in this regard would show that a major share of revenue expenditure goes into paying salaries and wages to the employees of the municipal corporations and utility boards. These expenditures are often referred to as unproductive

[5] The total expenditure for the CMC also includes the expenditure made by the CMWSSB in its revenue and capital account.

expenditure mainly keeping in mind the extent of redundant staff generally maintained by the municipal corporations. Moreover, a substantial share of the redundant labour force is in the sanitation sector.

Table 8 provides the detail of the share of establishment and maintenance expenses to the total revenue expenditure made by the local authorities on water supply, sewerage, and solid waste disposal in Ahmedabad, Chennai, and Pune. The establishment expenses, that is the expenses on salaries and wages, account for a substantial share of the total revenue expenditure incurred on solid waste disposal. This is mainly due to the fact that solid waste disposal is significantly labour-intensive. In all the three cities, on average, the expenditure on salaries and wages in the solid waste disposal accounted for almost 90% of the total revenue expenditure (Table 8).

On the other hand, the expenditure pattern on salaries and wages in water supply does not reveal a similar picture. The PMC has succeeded in keeping the share of about a quarter of total revenue expenditure during the initial years. However, it has regularly reduced except in 1993/94. The years as shown in Table 8 have shown remarkable decline in the share. Expenses of establishment for the AMC have not been as significant as in the case of the PMC for water supply. However, unlike the PMC, it has registered an increase over the years. It may, perhaps, be due to the new recruitment of the professional staff at the middle level in the individual sectors. The existence of a utility board for the maintenance of water supply and sewerage in Chennai has resulted in a higher share of establishment expenses in this sector. It accounted for almost 45% of the revenue expenses on water supply in 1990/91. However, the board has succeeded in reducing the share over the years and it has reduced to about 30% during the later years of the decade.

The establishment expenses in sewerage accounted for almost similar share of the total revenue expenditure as that of the establishment expenses on water supply during the initial years for the PMC. However, unlike water supply, sewerage did not show much of the decline in the share, rather there was some increase in 1991/92 and 1992/93. However, the establishment expenses in sewerage for the AMC accounted for 70.99% of the total revenue expenditure of the sector in 1990/91, which increased in 1991/92 (Table 8). However, with the improvement in collection efficiency of the related taxes and charges during the later years,

Table 8 Shares of salaries and O&M in revenue expenses of water supply and sanitation sector

Supply and O&M expenses	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/2000*
Ahmedabad										
Share of revenue expenditure to TE	90.25	89.00	89.89	91.97	90.01	85.91	81.63	84.70	83.79	65.47
Share of S&W in TRE for water supply	18.09	16.64	17.68	17.94	20.19	21.76	23.77	20.99	26.46	28.33
Share of O&M in TRE for water supply	4.75	5.39	5.24	5.78	6.32	6.96	5.25	5.19	5.84	6.38
Share of S&W in TRE for sewerage	70.99	72.28	57.72	57.73	56.86	65.40	56.94	51.63	41.90	42.28
Share of O&M in TRE for sewerage	16.58	14.57	14.25	12.99	17.09	11.18	13.53	14.37	12.92	12.60
Share of S&W in TRE for SWD and sanitation	93.00	94.50	92.60	88.66	85.00	88.60	92.80	95.45	93.13	92.95
Share of O&M in TRE for SWD and sanitation	6.13	1.93	5.00	9.53	10.92	9.83	6.27	3.05	5.67	5.53
Pune										
Share of revenue expenditure to TE	66.70	62.33	60.52	56.33	54.95	53.75	47.12	49.08	47.64	63.94
Share of S&W in TRE for water supply	24.65	17.42	18.50	20.30	15.97	12.37	11.05	10.78	11.32	8.94
Share of O&M in TRE for water supply	1.82	1.56	1.87	2.62	1.99	1.76	1.78	1.96	2.50	2.25
Share of S&W in TRE for sewerage	26.31	31.14	32.15	24.98	25.65	24.36	23.04	25.38	22.68	22.82
Share of O&M in TRE for sewerage	0.92	1.22	1.67	1.21	1.37	1.93	1.28	1.16	4.28	3.72
Share of S&W in TRE for SWD and sanitation	90.54	91.88	84.95	92.62	93.88	93.51	92.99	93.75	90.12	93.41
Share of O&M in TRE for SWD and sanitation	0.005	2.15	4.26	5.03	4.48	4.68	4.51	4.25	4.30	4.95
Chennai										
Share of revenue expenditure to TE	67.74	70.56	69.25	56.67	62.82	58.00	61.13	57.74	58.41	60.95
Share of S&W in TRE for water supply	44.70	40.45	40.27	40.34	30.35	29.57	30.78	29.74	24.15	28.10
Share of O&M in TRE for water supply	10.71	10.97	9.53	9.29	10.81	10.48	9.30	8.43	8.05	8.54
Share of S&W in TRE for sewerage	37.26	33.72	33.56	34.13	25.68	24.98	26.05	24.79	19.92	22.43
Share of O&M in TRE for sewerage	20.31	21.34	19.08	18.21	21.03	20.38	19.39	15.98	15.27	16.15
Share of S&W in TRE for SWD and sanitation	89.37	90.28	89.29	86.99	90.67	92.13	93.30	87.07	88.86	87.24
Share of O&M in TRE for SWD and sanitation	4.31	4.02	2.50	2.76	3.59	2.75	2.26	3.50	2.55	1.99

O&M – operation and maintenance; S&W – salary and wages; SWD – solid waste disposal; TE – total expenditure; TRE – total revenue and expenditure

Sources Budgets of AMC, CMC, PMC, and annual accounts of CMWSSB the share has gradually reduced except in 1995/96. Almost a third of the total revenue expenditure on sewerage for the CMWSSB has gone towards salaries and wages. The shares have, however, gone down during the later years (Table 8) except in 1993/94. There has been an increase in the share of the establishment expenses since mid-1990s due to the implementation of the 'Fifth Pay Commission' recommendations. The higher incidence of establishment expenses is often cited as a major problem facing the water and sanitation sector in urban India today.

A general phenomenon of the water supply and the sanitation activities in India is the low level of maintenance expenditure, which has led to faster deterioration of the existing assets. This has further increased the need to invest in new facilities in recent years. This is often cited as a major reason for the poor condition of the sector. Moreover, the lower level of expenditure on the maintenance activities is generally explained on the ground of poor financial situation of the city governments. The utility boards and urban local bodies are in most cases responsible for the maintenance of these services. An analysis of the situation in the three cities, if not thoroughly, partially supports the views mentioned above. Pune, one of the cities with a population of a million in India, spends something between 1% and 2% on maintenance activities of water supply and sewerage activities taken separately (Table 8). Moreover, the share did not show any remarkable increase during the later years.

Even if systems are developed, which need huge capital investments, it is the lack of maintenance that hastens the process of deterioration of facilities making the situation worse. The AMC replicates almost a similar situation, particularly with respect to water supply. In 1990/91, the share of operation and maintenance expenditure on water supply accounted for just 4.75% of the total revenue expenditure. Moreover, the share did not show any significant increase during the later years and has remained around 5% except in 1994/95 and 1995/96 (Table 8). However, the maintenance expenditure seems to be comparatively better in sewerage though there has been a declining trend in it during the later years of the decade. The maintenance expenditure on sewerage in Chennai on the other hand, on average, accounted for a fifth of the total revenue expenditure of the sector. This can well be cited as an advantage of having a separate utility board for these services. However, the 74th Amendment of the Indian

Constitution has put the water supply and sewerage activities as two of the obligatory functions of the city governments. Thus, to improve the financial situation of local bodies, there is a need for a complete restructuring and a more commercial approach of providing basic services. The later years in Chennai have, however, shown a declining trend in revenue expenditure on sewerage particularly in 1997/98 and 1998/99 (Table 8). The maintenance expenditure on average accounted for just 10% of the total revenue expenditure on sewerage. Moreover, there has been a significant decline during the later years of the decade.

The poor situation of solid wastes in the larger cities in India is well known. There does not exist a single city in India that has a sanitary landfill facility. In most of the cases, there has been a tendency on the part of the workers to keep the required machineries out of order to avoid taking up collection and disposal on a regular basis. The maintenance expenditure shares have remained meagre. The increasing salary expenses due to the increase in the number of sweepers on roll accompanied with a declining maintenance expenditure led to the poor condition of solid waste management. This accounted for a substantial increase in revenue expenditure on salaries and wages. Moreover, it is due to the characteristics of the solid wastes and the way in which the collection is done in the urban areas in India. These are largely unfit for the purpose of incineration and/or composting. Barring a few larger corporations, solid waste is collected just for the purpose of landfill. The lower incidence of maintenance expenditure accompanied with surmountable establishment expenditure makes the situation even worse. In recent years, many cities have gone for privatization of solid waste management, which has proved to be cost-saving. The industrialized nations that have privatized these activities generate sufficient revenue out of the composting and incinerating of the solid wastes. In these cases, it is the responsibility of the private operator to arrange for the capital investment funds required for establishing an incinerator or a composting treatment plant. However, since most of the cities in India do not have such facilities, the basic function in this sector boils down to collect the wastes and dispose them in specified landfill sites. Thus the sector could neither impose any tax to cover the collection and disposal costs, nor could it remain in a position to utilize the wastes for revenue generation.

Table 9 Collection efficiency of the various water- and sewerage-related taxes and charges

Collection efficiency	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/2000*
Chennai										
Water tax										
Percentage of collection to current demand	91.84	105.11	71.95	109.38	118.12	79.61	99.75	27.39	106.70	55.30
Percentage of collection to total demand	34.50	40.05	34.38	37.53	48.87	44.64	57.15	24.72	31.66	30.94
Sewerage tax										
Percentage of collection to current demand	91.81	105.09	71.94	109.36	116.78	85.83	99.68	27.34	106.71	55.18
Percentage of collection to total demand	34.49	40.05	34.37	37.53	48.31	48.12	57.11	24.68	31.66	30.87
Water and sewerage charges										
Percentage of collection to current demand	101.23	94.00	90.36	98.10	99.24	99.24	104.74	89.14	84.75	99.49
Percentage of collection to total demand	64.23	58.41	64.99	62.42	80.89	75.77	78.54	67.77	59.46	72.61
Pune										
Water tax										
Percentage of collection to current demand	22.19	22.87	22.37	17.65	20.14	23.34	17.21	17.44	27.51	28.49
Percentage of collection to total demand	13.02	11.96	12.39	11.39	13.74	15.94	12.75	13.61	21.97	21.99
Water benefit tax										
Percentage of collection to current demand	NA	91.46	80.82	98.72	77.09	80.32	78.00	80.83	86.09	99.26
Percentage of collection to total demand	NA	65.79	63.44	78.61	65.57	65.43	63.79	67.60	71.12	86.54
Sewerage tax										
Percentage of collection to current demand	80.63	97.84	92.51	79.61	83.48	93.70	83.20	83.20	87.48	95.59
Percentage of collection to total demand	52.24	54.67	52.82	49.91	50.63	56.48	55.21	55.05	56.21	69.32

Sewerage benefit tax										
Percentage of collection to current demand	NA	85.60	105.48	106.55	104.91	109.14	105.66	101.87	108.79	88.36
Percentage of collection to total demand	NA	60.45	75.00	77.42	78.04	79.08	78.27	78.17	89.98	78.69
Water charges										
Percentage of collection to current demand	82.54	92.58	95.63	85.47	90.08	92.73	94.85	95.48	97.85	91.55
Percentage of collection to total demand	60.12	62.08	66.58	61.89	62.87	64.55	66.23	66.45	70.14	68.65
Ahmedabad										
Water tax										
Percentage of collection to current demand	42.37	38.52	47.10	39.45	58.15	63.63	82.39	44.67	51.31	53.94
Percentage of collection to total demand	12.86	11.39	13.47	15.17	19.37	19.47	24.09	18.64	22.45	23.30
Water charges										
Percentage of collection to current demand	25.87	NA	28.53	37.74	52.92	62.52	104.83	39.06	91.94	144.40
Percentage of collection to total demand	6.70	NA	7.00	7.59	10.31	12.93	22.23	16.96	34.92	54.24
Conservancy tax										
Percentage of collection to current demand	55.88	38.89	49.39	42.24	56.63	64.20	81.24	42.81	78.22	78.41
Percentage of collection to total demand	19.72	11.09	15.20	14.62	17.92	18.70	23.13	16.34	31.64	31.09
Conservancy charges										
Percentage of collection to current demand	32.75	NA	36.71	42.04	64.33	67.84	86.77	62.67	80.54	82.87
Percentage of collection to total demand	6.84	NA	8.17	10.25	16.15	17.29	21.76	20.99	38.86	44.67

NA – not available

Collection efficiency of taxes and charges

An attempt has been made to look into the collection efficiency of the various taxes and charges levied on water and sewerage in these three cities. Table 9 presents the detail of the collection efficiency of these taxes and charges in Ahmedabad, Chennai, and Pune. The AMC levies water tax and water charges so does the CMWSSB. In addition, the CMWSSB also imposes sewerage tax and sewerage charges. However, sewerage charges are a fixed proportion (25%) of the water charges where sewerage connections are provided. In Ahmedabad, these are known as conservancy tax and conservancy charges.

The AMC collects water taxes from the domestic consumers with domestic connections in Ahmedabad municipal area being largely non-metered. Water charges are levied on industrial and commercial consumers. They make the payment on the basis of the volumetric measure of water consumed. Chennai, however, has a substantial number of metered domestic connections so does Pune, and charges are made based on actual consumption. Where the metres are not in working condition, two types of measures are adopted. Firstly, water taxes are collected on the basis of the ARV of the property; secondly, the amount of water consumed is estimated on the basis of the diameter of the pipe and is charged accordingly. The sewerage taxes are also collected as a fixed percentage of ARV of the property. Sewerage charges are generally a fixed proportion of the water charges. Table 9 provides the details of the ratio of collection of various taxes and charges to current and total level of demand. A comparative analysis of the collection efficiency of taxes and charges reveals that seldom the municipal corporations and the CMWSSB could collect the arrears that are due for long. At the most the agencies could collect a major share of the current demand. However, the current demand generated after the tariff revision was also collected.

A comparative analysis reveals that the collection mechanism is more efficient in the cities of Chennai and Pune. The CMWSSB could also collect some of the accumulated arrears. This is revealed by the fact that the ratio of collection to current demand for water and sewerage taxes exceeds 100% for water tax in 1991/92, 1993/94, 1994/95, and 1997/98 (Table 9). However, arrears demand of water and sewerage charges could only be collected in 1990/91 and 1996/97 by the CMWSSB. The overall collection efficiency[6] for the CMWSSB has rarely exceeded 50% for water and sewerage taxes. However, both Chennai and Pune could efficiently collect the current demand of the water and sewerage taxes and charges (Table 9). The ratio of collection to current demand of water and sewerage charges has remained more than 90% during most of the years. The collection efficiency seems to have fluctuated both for the PMC and CMWSSB, which lack the necessary consistency. However, in most of the cases, the ratio of collection to current demand has remained significantly low for water and conservancy charges for the AMC. Despite fluctuations during the 1990s, there has been an overall increase in the collection efficiency during the later half of the decade. This could be accounted to the measures adopted during the later half for improving the finances of the corporation. The organizational structure of the provision of water supply and sewerage in a particular city has some implications for the successful performance of the sector, particularly in terms of cost recovery and collection efficiency.

Conclusion

One can conclude that there is a need for an initiative to take measures to collect the accumulated arrears in this sector. However, this has to be done gradually such that the burden does not fall on the beneficiaries all of a sudden. The 100% collection efficiency of the current demand accompanied with the support of the locally elected representatives for collection of the accumulated arrears would make the sector self-sufficient without having to depend on other sources of revenue. The generally low figure of the collection efficiency of the water-related taxes and charges have contributed significantly towards the poor situation of the water supply and sanitation sector as a whole. It has further contributed towards a chronic deficit in the sector leaving no room for improvement. The lesser implementation of the user-charges has further added to the problems of the sector. Moreover, the declining share of the user-charges over the years has been a noticeable phenomenon for Pune and Chennai.

[6] Ratio of collection to total (current plus arrears) demand.

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So far so good: experiences and challenges in the Scandinavian power market[1]

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Abstract

The Californian power market crisis in 2001 and power blackouts in New York and Italy in 2003 have questioned the robustness of market-based power systems. Electricity reforms in Scandinavia have so far been a success story, and represent the only truly international power market. This article explores the experience and the future of the Scandinavian electricity market, using a scenario analysis to explore what is required to extend the present success story. It is evident that the Scandinavian market will require new investments if a price and supply crisis is to be avoided. Low prices, security of supply, and environmental concerns will remain key energy policy aims, but the coming capacity crunch is likely to rise to the top of the agenda and increase the risk of heavy handed political intervention. Power sector regulation is getting ever more complex and consumes increasing resources, and the scope of regulation is growing. The process of restructuring is likely to reduce the number of actors in all parts of the supply chain, and the dominant role of public ownership may be undermined as the region increasingly integrates into continental Europe.

[1] Based on analyses of the ECON report (ECON 2002b) by ECON Centre for Economic Analysis, September 2002.

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A robust electricity market?

Electricity deregulation in Scandinavia has so far proved to be a success story. The Scandinavian market is highly competitive, well functioning, and the only truly international power market. This article explores the future of the Scandinavian electricity market and discusses what is required to extend the present success story.

The move towards competitive electricity markets started over ten years ago in the Chile, Norway, and the UK (Jamasb and Politt 2000). During the past decade several other countries have passed similar reforms, often with the effect of reducing the former inflated price levels. However, the fall in prices, which has given the reforms general credibility, is primarily explained by considerable surplus capacity in the old systems. Surplus is now eroding fast, as demand continues to grow in a society increasingly dependent on electrical appliances and technologies.

There is a growing concern over the ability of market-based power systems to generate sufficient and timely investments. This is related to the question of whether competitive electricity markets are synonymous with cyclical investment and price patterns. The power crisis in California (ECON 2001) and difficulties in the UK show that a reliable, stable, and efficient electricity market is difficult to put in place. Market regulations and institutions must constantly be re-examined and the role of the regulator is more likely to expand with the growing understanding of the complexity of the system, rather than fade away as the market reform evolves.

The Scandinavian success story

A decade of reforms

Electricity reforms in Norway and Sweden are the most extensive and arguably the most successful in the world. Prices have fallen, productivity has improved, and the market is highly competitive. Denmark is also catching up. The Scandinavian electricity market (together with Finland) is the first and so far the only truly *international* market where producers and consumers in several countries can trade freely with each other in a single power exchange.

A distinct feature of the Scandinavian reforms, compared to other countries, is the slower pace of privatization and dominant role of public ownership. The focus of reform has primarily been on establishing competition and not on privatization. However, there has been a strong commercialization of the power sector over the past few years.

Norway

The Norwegian market reform was passed in the parliament in 1990 and the institutional framework was put in place by early 1993. The central grid and system responsibilities were split from the major public company Statkraft into a separate entity—Statnett. Utilities were required to separate accounts for grid and production or supply activities, and rate of return regulation was introduced for grid activities. To increase efficiency, income caps replaced rate of return regulations from 1997.

The TPA (third-party access) to the grid was established and point (not distance related) network tariffs introduced. The previous quasi-market for occasional power was expanded through the establishment of a spot market in 1993, and a futures market in 1995 to a full-fledged market known as the Nord Pool market. Retail competition was introduced in 1991 and all barriers to full retail competition were removed in 1997.

Sweden

The Swedish reform took effect in 1996 with many institutional similarities to the Norwegian one. Trading in the Nord Pool was extended to Sweden, which represented a separate price area. Sweden did not impose a strict formal regulation of grid companies, but a form of price cap; in the sense that the regulator stated that tariffs should not increase. Sweden also required a complete de-merger of distribution and production or supply activities. Barriers to change of supplier for small customers were removed in 1999.

Denmark

Denmark joined the open Nord Pool market in 1999/2000 and opted for a gradual opening of the end-user market with full opening planned for 2003. Danish grid regulations have elements from both the Norwegian and Swedish systems, using income caps as well as requiring a de-merger of distribution and production activities.

A common market place: Nord Pool

Prior to the creation of the Nord Pool, national champions such as Statkraft and Vattenfall controlled foreign trade. By January

1996, the Norwegian and Swedish markets were integrated. The Swedish grid company – Svenska Kraftnät – acquired 50% of the Statnett Power Market, which was then renamed Nord Pool. Later in 1996, Finnish companies gained access to the Nord Pool market and the Finnish power exchange merged with the Nord Pool in 1998. Denmark became stepwise a part of the Nord Pool, first with Jutland in 1999 and then with Zealand in 2000. Today power in all four countries – Denmark, Finland, Norway, and Sweden – is traded on the Nord Pool.

Trade

The Scandinavian power systems can roughly be divided in two categories: the hydro-based system in Norway and northern Sweden, and the thermal system of Denmark, southern Sweden, and Finland. A hydro-based system is constrained by the amount of energy available over time whereas a thermal one by the peak capacity. Due to the complementary nature of hydro- and thermal-based systems, trade in Scandinavia has always been extensive and well organized. Before reforms, a regulated market existed for trade among national peers across borders.

Doing away with the goal of national self-sufficiency allowed for the full potential of integration to be harvested. The abolishment of national self-sufficiency policies came at a time of surplus. Denmark has been the surplus provider, and governments in Norway and Sweden have been able to avoid the environmental and political costs related to new large-scale generation.

Increasing trade and integration across borders was also facilitated by a more efficient and transparent trading system under the Nord Pool as well as the easier TPA to the grid and inter-connectors.

After liberalization, gross trade volumes increased and net trade flows shifted significantly. Norway and Sweden have become net importers in a hydrologically normal year and Denmark a net exporter, reversing previous trade patterns.

Unleashing competition worked

After liberalization, the end-user prices started to fall in both Sweden and Norway. The Danish reform has not triggered similar price reductions since the obligation to buy an increasing portion of renewable power has raised prices. Generally, electricity prices for industry have come down the most. The downward trend in electricity prices (Figure 1) is mainly explained by

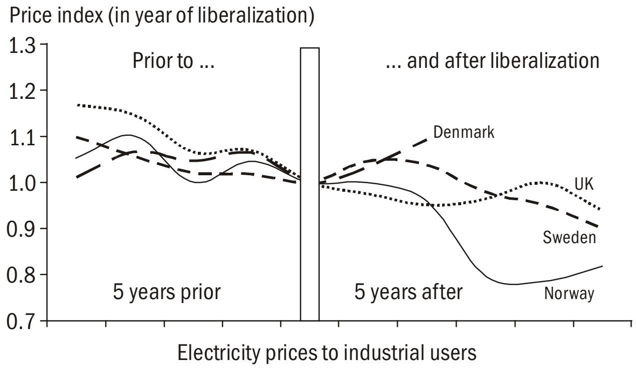


Figure 1 Prices fall after liberalization
Source ECON (2002b) and IEA online statistics available at http://data.iea.org/stats/eng/main.html

excess capacity in the pre-reform system, and cost savings in the grid part of the system (ECON 2002c).

An indication of the advanced state of the Scandinavian liberalization is that end-user prices reflect spot price developments. Unlike the former UK Pool, price fluctuations are passed through to the end-user (Figure 2). This is most pronounced in Norway where retail competition has evolved the most.

The competitive nature of the Scandinavian market is demonstrated by the fact that spot prices are close to marginal costs. Another indication of a competitive market is low retail margins. Trade margins have been shrinking for most customer groups. An important reason for the market remaining highly competitive is the predominant municipal and public ownership, which has restricted the consolidation process in Norway and Denmark and limited strategic behaviour. Anti-competitive behaviour has been practically non-existent. Public ownership is a barrier to mergers and acquisitions in generation, and decentralized municipal ownership allows for many participants and open competition in the wholesale market.

Investments

At the beginning of the 1990s, surplus capacity in the Scandinavian electricity system was significant. In anticipation of continuing strong growth in consumption, considerable investment decisions were made in the 1980s, but the actual growth proved to be lower than expected. However, an electricity

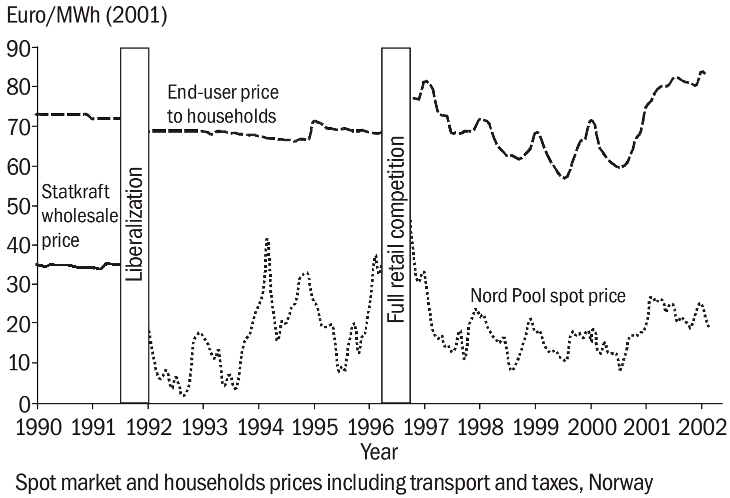


Figure 2 Price pass-through to consumers
Source ECON (2002b)

system highly dependent on hydropower (where the resource from year to year can vary by ±20%) and where electricity is used for heating requires considerable swing capacity and demand flexibility to handle cold winters and dry years.

As part of the liberalization process, self-sufficiency was abandoned in favour of a common regional market. An optimally designed Scandinavian market would allow for significant savings in total capacity compared to stand-alone systems. A very important benefit of the reforms has therefore been delayed investments in the new capacity in Norway and Sweden.

In Sweden, the presence of a considerable surplus capacity facilitated the political objective to decommission the nuclear plant Barsebäck I. In addition, an expensive oil-fired capacity was mothballed because no one would bear the cost of maintaining it. As a result, the capacity is barely larger today than ten years ago, although consumption has been steadily increasing (Figure 3).

An overburdened and conflicting policy agenda

The energy policy triangle

Energy policy is constructed in a complicated interplay and trade-off between three fundamental concerns: economic efficiency (low prices), security of supply, and the environment (Figure 4).

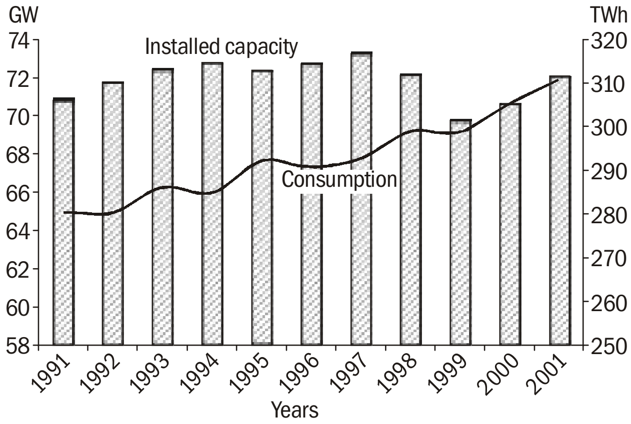


Figure 3 The coming capacity crunch
Source *Nordel Annual Statistics* (available at www.nordel.org)

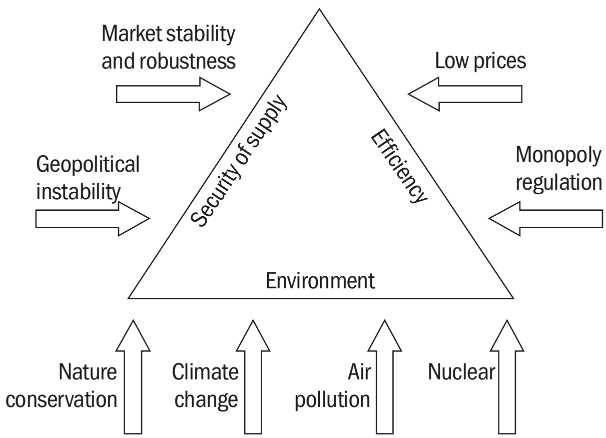


Figure 4 The energy policy triangle

The three goals are partly incompatible and the level of tension between them varies over time. During the 1990s, surplus capacity made it possible for Norway and Sweden (not Denmark) to pursue both environmental goals and lower prices simultaneously without compromising on security of supply. However, as the capacity balance tightens, trade-offs will again become more apparent. Pursuing environmental goals literally comes at a price and expanding capacity to keep prices down will conflict with environmental goals.

Scandinavia: common market with a differing policy agenda

Despite a common electricity market, Scandinavian countries do not share the same priorities in their respective energy policy agendas (ECON 2002b). Energy resource endowments, consumption patterns, and political priorities explain the differences. The energy policy triangles have distinct national flavours. As such, a Scandinavian energy policy does not exist.

Denmark

During the 1990s, Denmark aimed for ambitious and costly environmental goals. Electricity covers a much smaller part of heating than in Norway and Sweden, besides the energy-intensive industry is small. This has allowed successive governments to increase electricity taxes and introduce the mandatory use of electricity produced by renewables and local cogeneration plant (CHPs [combined heat and power plants]). The extensive support to the wind-turbine industry has also become part of the Danish industrial policy. With the change of government in late 2001, environmental ambitions seem to have been scaled down and a greater focus is now placed on low prices and sectoral efficiency.

Norway

Norway's abundant and cheap hydropower is the basis for a considerable power-intensive industry, extensive use of electricity in household heating, resulting in the highest per capita electricity consumption in the OECD (Organisation for Economic Co-operation and Development). Maintaining low electricity prices is more or less a political requirement. Conservation has become an effective barrier to the development of additional hydropower plants, and also limits wind power development. Natural gas from the North Sea provides the potential for relatively low cost CCGT (combined cycle gas turbine), but would add significantly to carbon emissions in the hydropower-dominated system. Therefore, energy policy is politically sensitive due to the large oil and gas industry, power-intensive industry, and household electric heating in a cold climate.

Sweden

Nuclear power was built in the 1970s and 1980s in addition to the existing hydropower to secure the supply of low electricity prices to heavy industries. Public concern over nuclear power led to the decision to decommission all nuclear reactors by 2010, but only one has been closed to date and decommissioning is still on hold. Biomass is stimulated for CHP and district heating, which goes well with the increased national supply of waste from the pulp industry. Concerns over peak capacity and security of supply dominate the current debate, and together with conservation and climate issues, may well indefinitely delay decommissioning of any nuclear plants in the future.

A complicated balancing act

Most likely, the present political agenda will change significantly over the next decade. Climate change and market liberalization may not necessarily dominate priorities as of today. The energy agenda will remain a complicated and pragmatic balancing act requiring trade-offs between conflicting goals. The 1990s have lured many policy-makers in Norway, Sweden, and abroad, to believe that market liberalization can address most of what we want to see happen in terms of environment, low prices, and stability in society and to think that few hard choices need to be made. This decade may well prove them wrong!

Regulation: creeping into courts?

The power system is a key infrastructure in modern society, and has features of externalities (environment), natural monopolies (network), cyclical investments, and public good (reliability and security of supply). A market-based power system will not work without the support of a well-designed regulation that is able to develop and adapt to the dynamics of change. The Californian crisis illustrates how badly things can go wrong (ECON 2001).

Figure 5 illustrates the three key elements of regulation of the electricity industry.

1. *Regulation of network monopolies* Secure open access to networks, avoid undue monopoly profit, secure quality of services, and address other aspects related to the natural monopolies of distribution and transmission.
2. *Competitive markets* Market surveillance is most often the formal responsibility of the competition authorities, but the industry regulator is increasingly involved in this issue as industry consolidation may limit competition.
3. *System design* The regulator has the responsibility to see to that the entire electricity industry (monopoly and market

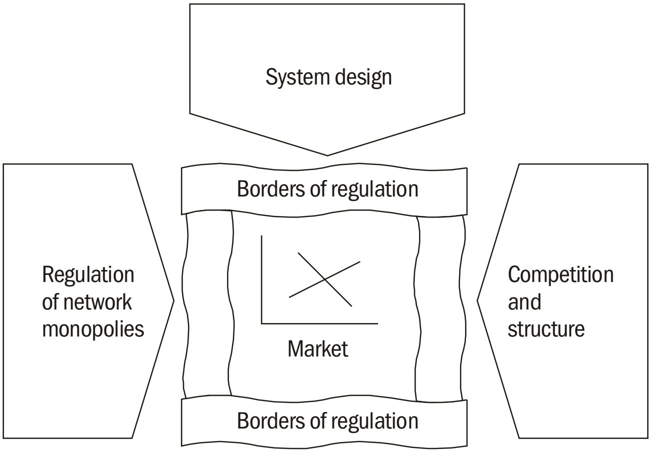


Figure 5 Elements of regulation
Source ECON (2002b)

parts) works efficiently and securely. Issues involved include coordination of planning activities between grid owners and market participants, and the institutional arrangements around the operation of the system and the market place.

Competition was expected to decrease the role of regulation. So far, the tendency is for regulation to expand in scale and scope.

Increasing complexity of market design

The design of the entire power system is getting increasingly important and new issues persistently seem to appear on the agenda. The importance of competition and market design was best illustrated with the drop in prices after the NETA (new electricity trading arrangements) were introduced in England and Wales (Ofgem 2002). Allowing dynamic developments in market and system design is vital to maintain a well-functioning market.

Investments in generation, transmission, or demand-side management may be substitutes to securing sufficient power in an area (Bråten 2001). To combat market power, competition authorities may split existing generators into several entities, add new transmission capacity to attract outside competitors, or allocate licences to new producers to build capacity in a high price area. The cost to the economy of one or the other solution may differ significantly, and the best solution does not always arise from market forces. The regulator must be responsible for ensuring that markets and network regulations interact with efficient outcomes, and also be in a position to encourage the best solutions. This adds to the complexity of system design and regulation in an international power market.

Stronger Scandinavian coordination

There are different national regulatory authorities for the power sector, with different powers and links to other important authorities such as environmental agencies, competition authorities, and ministries. There are also a set of transmission system operators—one in each of Finland, Norway, and Sweden, and two in Denmark. At the same time, these different regulators operate within a common market. The urge for stronger coordination and harmonization of regulatory systems is evident.

The investment problem

During this first decade of the Scandinavian market-based electricity system, markets have enjoyed comparatively low wholesale electricity prices. However, in 2002 a dry autumn and cold winter gave unprecedented high prices, and markets in certain other countries have also experienced high and volatile prices (for example, New Zealand). This volatility is almost invariably associated with the tightening of supply capacity, often as a result of stochastic factors such as drought, extreme weather conditions, combined with increased demand eroding reserve margins (ECON 2002d).

For some observers, increased volatility combined with rising price levels are interpreted as a symptom of market failure. However, price response to supply constraints are a fundamental and predictable feature of competitive markets. The big difference between the Scandinavian and the failing Californian market was illustrated last winter where prices influenced trade, generation, and consumption reductions so that the Scandinavian market managed the tight hydro supply situation. Furthermore, price signals are a necessary feature to stimulate investment as capacity limits are reached.

It is useful to distinguish between two aspects of the investment problem.

1 Will liberalized markets provide price signals that attract an efficient level of investment? In this context, do markets require special mechanisms to provide these price signals?

2 Will higher and more cyclical prices as surplus capacity is eroded attract political or regulatory intervention that distort the price signals of the market?

Tinkering with the system

Electricity shares a number of characteristics with other capital-intensive industries, like the long lead-times, from the decision to build a new plant until it is up and running. Similar to other industries are also the complexity and scale of environmental problems.

A more specific feature of the electricity market is the need to balance in real-time, that is whatever the marginal consumer decides to consume, the system must make available. In fact, the system requires a range of ancillary services, including reserve capacity, to maintain the quality of supply. Another important feature relates to the physical constraints and interdependencies in the grid. Producers are able to sell and consumers to consume only to the extent that the capacity in the grid allows.

A competitive electricity market needs prices that ensure that investors build sufficient capacity to maintain a minimum surplus or reserve. This will not be provided in a free market, and some 'tinkering' with the system such as a special pricing mechanism for reserve capacity is needed.

Cyclical or stable market?

Most capital-intensive commodity markets show cyclical patterns in investment and prices. Will that also be the case for electricity? In a sense, two rather different perceptions may apply.

The economist's textbook perception of a stable and predictable world is depicted in Figure 6. After a transition period, where the failure (i.e. over capacity) of the old system is rectified, prices will gradually move towards the full cost of adding new capacity. After that, prices will gravitate around this level in a rather stable manner.

In Figure 7, the story is however different. Investment patterns turn out to be cyclical and so are prices. This pattern can be explained by business cycles, the fight for market shares, large and indivisible capital investments, and not least policies. Of importance in this perception is the fact that these kinds of cyclical patterns are observed in a number of other highly competitive commodity markets, like the markets for oil and steel.

When thinking about the future of the Scandinavian electricity market, it is uncertain which mental model will apply. However, the political response to each model will be very different.

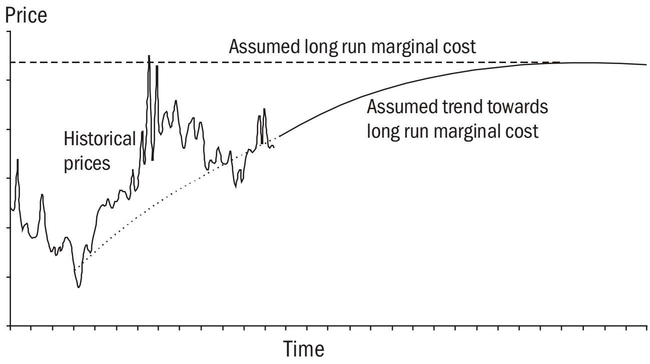


Figure 6 Towards a stable and predictable world...
Source ECON (2002b)

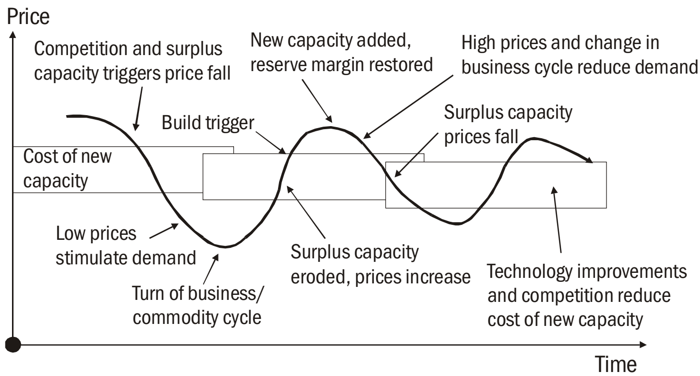


Figure 7 Towards a cyclical world?
Source ECON (2002b)

Commercial forces and restructuring

Liberalization has unleashed forces that are changing the electricity industry like never before. The Scandinavian power sector stands out in an international context with its high degree of public ownership (Figure 8) despite extensive liberalization and a highly developed common market.

Structural reform has been significant. The monopoly transmission activities are separated (at least in accounts) from generation and other market-based activities. There has been substantial vertical integration with generation companies entering into activities throughout the value chain, and there is an ongoing horizontal integration (mergers and acquisitions) between companies at the distribution and retail levels. Dominant

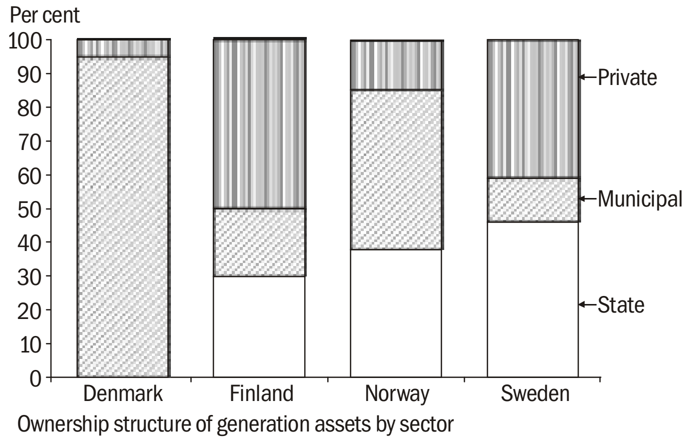


Figure 8 Public ownership remains dominant in Scandinavia
Source ECON (2002b)

players have so far concentrated on consolidation at home with pan-Nordic strategies beginning to emerge only recently. Vattenfall's expansion from Sweden to across northern Europe illustrates the widening geographic scope, but integration with Europe is only at a very early stage (PriceWaterhouseCoopers 2001). If, or when, the commitment to public ownership lessens, a wave of changes will occur, most probably dominated by large European utilities.

The new picture of a pan-European power industry is emerging: there is already a set of super-league players whose interests are both multinational and multi-utility. Germany has two companies – E.ON and RWE[3] – which have gained a leading position across the continent. E.ON and the French EDF[4] (equal to above) have already taken positions in Scandinavia, and many smaller companies may be vulnerable to acquisitions by these giants. The radical changes currently taking place in the European power sector suggest that the Scandinavian process of integration and reorganization could easily be caught up in a larger Europe-wide set of events. Still the ownership restrictions and the presence of public ownership restrains the process, but the harmonization of the European Union also challenges these regulations and limitations to a free market. The commercial

[3] Formerly known as Rhein Westfalische Elektrisitätswerk.
[4] Formerly known as Electricite de France.

forces of the market are driving structural changes, but political factors still have a role to play.

Challenges for the future

Investments and capacity crunch

It is evident that the Scandinavian market will require new investments if a price and supply crisis, as experienced in California, is to be avoided. The investment challenge may well be different in different regions: in some places the constraints are on energy, in others on peak capacity. We see a number of alternative routes in the way that the market and political system may respond.

- *Living with the market* As with other commodity markets, investment will ultimately occur, however, most likely in a cyclical manner. Consumers (and politicians) learn to live with periods of extremely high prices and even with the threat of brownouts or blackouts.
- *Internalizing risks through vertical integration* Another option, not necessarily independent of the above, is investment by large and vertically integrated companies. Through size and vertical integration, it is possible to internalize at least some of the market risks related to new investment.
- *Politically or regulatory mandated investment* It is also possible that governments mandate, through their ownership of utilities or other special mechanisms, investment in new generation. To a large extent this contradicts the historical trend towards greater commercialization of the industry.

Policy: inconsistent and overstretched agenda

Low prices, security of supply, and environmental concerns will remain the main goals of energy policy. The balance between the three is probably shifting, as the coming capacity crunch is likely to rise to the top of the agenda, making measures that can contribute to additional capacity as a top priority. However, agreeing to the necessary compromises may not be easy.

- *Capacity versus environment* As the market tightens, higher prices will stimulate investment. Governments respond by increasing subsidies for preferred technologies. However, investment on the scale needed to secure the power balance is likely to push more heavily against environmental constraints than in the past decade, and large programmes to stimulate renewables are expensive.

- *Energy is too expensive for consumers, but too cheap for the environment* Energy market liberalization tends to exacerbate this conflict as it lowers prices, thereby stimulating consumption. The debate over green taxes illustrates the dilemma: we want higher prices but we do not want poor and energy-intensive industries exposed to competition to suffer.
- *Diversify fuel and technology versus decisions made by the market* Both security of supply and reliability of the market-based systems are public goods. One easily comes to the conclusion that the system should be diversified in terms of fuel and technology choice. However, in the market one often comes to the conclusion that one option is the preferred one.

Regulation: increasing scope and complexity?

Regulating the grids (monopolies) is important, and new aspects of market design, system coordination, and international trade are moving up the regulators' agendas. Power sector regulation is getting ever more complex and is taking up increasing amounts of resources, and the scope of regulation is growing.

The future of regulation is still uncertain. We can imagine different alternative developments.

- *Monopoly and competition regulation* The regulators concentrate on the traditional core elements of regulation and accept that there is a limit to what can be achieved through regulation (even though it is far from perfect). Protection of consumers is on the top of the regulators' agendas, in the form of TPA and competition policy.
- *Super regulator* Power systems have features of public goods, externalities, monopoly power, lumpy investments, and are a key infrastructure in the society. To cope with the complexity and conflicting interests, more regulatory power is given to super regulators.
- *European regulation* The national regulators are sidelined as European regulation of trade, tariff and tax harmonization, trans-European networks and competition has gradually realized.

A period of rapid transition

The restructuring of the Scandinavian electricity market has only begun. The number of actors in all parts of the supply chain is large and the dominant public ownership is seriously challenged. Many players are likely to disappear as the process of consolidation continues. Others may find themselves in partnership with European utilities.

We can imagine three different futures for the electricity industry in Scandinavia.

- *National focus* The countries of Scandinavia make great efforts to develop their own national champions, most likely publicly owned.
- *Regional competitors* The dominant commercial strategy proves to be to develop regional utilities with Scandinavia (plus Finland) as their home market.
- *Integration with Europe* The giant French, German, and the US 'super-utilities' succeed in integrating the Scandinavian electricity industry into their operations.

What will the future bring?

The Scandinavian electricity industry and policy-makers in each of the three countries may respond differently to the challenges outlined in the above section. To illustrate how these responses and choices will impact the future electricity industry in Scandinavia, we have formulated three scenarios to describe a set of plausible futures.

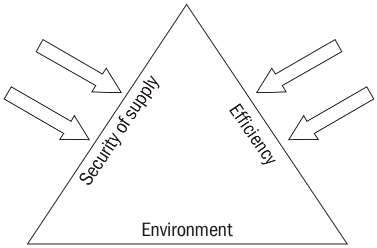
The three scenarios *Cyclinavia*, *Polinavia*, and *Marginavia* represent different ways in which key elements of the industry may evolve. They are intended to be illustrative rather than definitive, and the future may well combine different elements of these scenarios and will certainly include issues that we have not addressed.

The next year is expected to be a continuation of the past, but limited investments and restructuring prepare the scene for what is coming. The point of divergence for both *Cyclinavia* and *Polinavia* is the capacity crunch and price hikes in 2004, and distinct political responses that turn the history in specific directions. *Marginavia*, on the other hand, is more gradually drawn in one direction by changes in ownership restrictions and European restructuring extends to Scandinavia.

The following sections describe how these scenarios evolve. They are written in the present and past tense to underline that these are possible descriptions of the future as it evolves and not mere predictions from today.

Cyclinavia: A story about living with the market

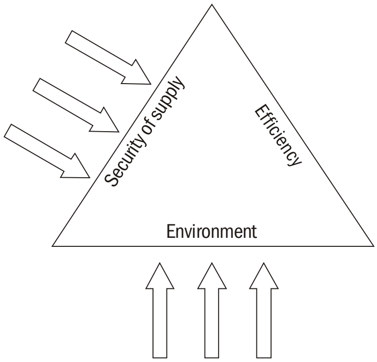
Supply has tightened in Norway and Sweden, and persistent high prices in the winter of 2004/05 creates a pressure for government action. Governments avoid heavy-handed intervention and lean on the strengthened institutional cooperation in the Scandinavian electricity market to steer clear of major crises. The system operators and regulators put in place measures to sustain security of supply without curbing the market.



Price *cycles* are part of the nature of the business, and are necessary to stimulate a degree of new investment. Combined with changes to market design this proves sufficient to balance the system, although prices cycle around relatively high levels. Integration across the Scandinavian countries continues, with an increasing level of cross-border ownership.

Polinavia: A story about national solutions and gas infrastructure development

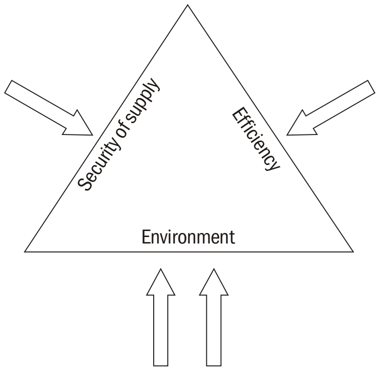
A capacity crunch de-links prices in Norway and Sweden from the continent and invokes a strong *political* response to increase capacity and bring prices down. The dominant state companies are given a more central role in developing new capacity. Investment is primarily politically rather than commercially driven, and public support for gas infrastructure encourages gas-fired generation. The resulting over- investment drives prices back to low levels in the last part of the period.



Denmark, however, links up to the German market and the more market-friendly continental policy environment. Thus the Scandinavian integration stands still, and the countries develop in separate directions.

Marginavia: A story about integration with Europe

The restructuring process currently taking place in Europe gathers steam, and extends to Scandinavia. A more relaxed policy towards private and foreign ownership allows the super-utilities of the continent to entrench themselves in the region, leaving the local industry in a *marginalized* position. Prices and investment in Scandinavia are closely integrated into Northern European market developments, and environmental policies are primarily determined at the EU level.



Market structure

Triggers for the three scenarios are the policy responses experienced after a price spike in the market in 2004 (Figure 9), when the market tightens due to several coincidental events. The living with the market story, *Cyclinavia*, has a well-integrated Scandinavian market based on institutional cooperation through a single Scandinavian system operator and a common transmission tariff system. Reserve markets are established to secure supply, and prices reflect the cyclical scarcity of capacity in the system. In *Marginavia*, Scandinavian markets are increasingly integrated with Continental Europe through ownership as well as increased inter-connector capacity supported by the EU programmes. Thus prices are strongly influenced by German prices and a successful liberalization of the northern European gas markets. In *Polinavia,* the political response is to regain national political control. Here Norwegian and Swedish markets

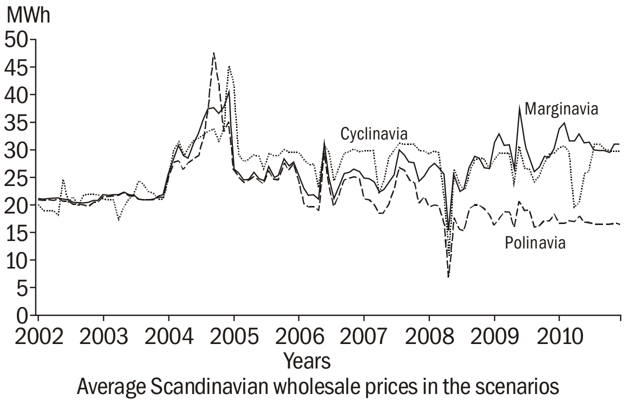


Figure 9 Spot market price developments, 2002–10
Source ECON (2002b)

again develop a strong national flavour, vertical integration again becomes predominant and bilateral trading common between associated utilities. Publicly mandated investment pushes prices down in Norway and Sweden in the past half of the period.

Industry structure

In *Cyclinavia,* large utilities in each country seek acquisitions and alliances in neighbouring countries, and Pan-Scandinavian companies become dominant. The emergence of gas-for-power projects provide for alliances between leading power and gas utilities. Privatization, particularly on the part of municipal owners, facilitates the consolidation and rationalization of the industry. In addition, governments decide to merge the transmission system operators of Denmark, Norway, and Sweden in order to facilitate system and market integration in an effort to bolster security of supply.

In *Polinavia,* the national orientation of energy policy and continued support for public ownership re-enforces and strengthens national champions that consolidate their position at home. They face competition from second-ranking regional players, typically linked to a European partner, but the persistence of public ownership leaves few opportunities for foreign actors to establish a significant presence in the market. Denmark is more oriented towards the European liberalization process, without affecting the industry structure significantly.

Contrastingly, in *Marginavia* privatization gives the leading European utility companies an opportunity to expand into Scandinavia. A series of acquisitions and alliances result in a configuration of utility clusters, each dominated by a leading European player. Trends in Europe, including gas-power convergence and multi-utility strategies, are also evident in Scandinavian countries.

Investments

In *Cyclinavia* and *Marginavia,* investment is primarily driven by commercial incentives, and the level is maintained at relatively low levels. Inter-connector capacity is increased in both scenarios *Cyclinavia* predominantly within the Scandinavian market, while the EUs support for European-wide networks facilitate significant expansions in inter-connectors between Scandinavia and the Continent in *Marginavia*.

In *Polinavia*, investment in generation is primarily driven by public policy, and environmental concerns steer investment towards green power. In *Polinavia* new subsidized gas infrastructure in Sweden and Finland lays the basis for CCGTs in Sweden. In *Marginavia*, liberalization of the European gas market encourages convergence between gas and power, while in *Cyclinavia* new investments in gas-fired power begin to come on stream only towards the end of the decade—primarily on the western coast of Norway where gas prices are the most favourable (Figures 10a, b, and c).

Trade

Marginavia, with Scandinavia closely interconnected to Europe, has the largest absolute volume of trade (Figure 11). *Polinavia*, due to its emphasis on (national) security of supply, has lowest traded volumes, though Denmark still trades extensively with Germany. In both *Cyclinavia* and *Marginavia*, the region as a whole is a net importer, as the market facilitates increased trade as an alternative to investment. In *Polinavia*, however, the high level of investment within Scandinavia makes the region a net exporter.

In all scenarios, Denmark is a net exporter, and Norway and Sweden are net importers. However, in *Polinavia*, the latter two countries are closer to being in balance than in the other scenarios.

Environment

Environmental policy priorities remain different between countries, but the common and largely unresolved issue is how to address greenhouse gas emissions. In *Cyclinavia*, environmental policies are downscaled to allow for significant market-based investments in capacity. Overall carbon emissions double compared to 1990, and the Kyoto accord's emission targets are downplayed. *Polinavia* attempts to balance a significant expansion of gas-fired capacity (to handle security of supplies) with extensive support for renewable alternatives. However, there are considerable economic costs of these policy measures. In *Marginavia*, new market-based investments in CCGTs add to CO_2 emission levels (Figure 12). However, the increased emissions are offset through the European market for emission permits established in 2005. This abatement policy is cost-efficient, and the scenario combines the least costs with the lowest level of net emissions.

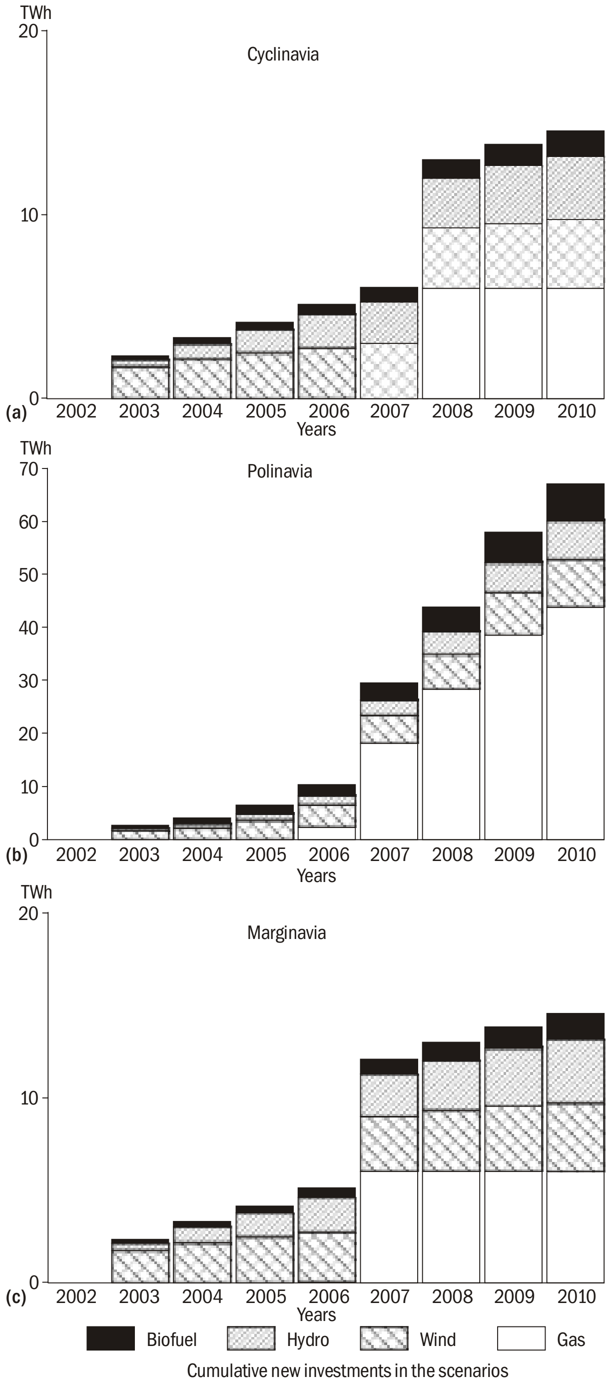


Figure 10 Investment in electricity generation in (a) Cyclinavia, (b) Polinavia, and (c) Marginavia
Source ECON (2002b)

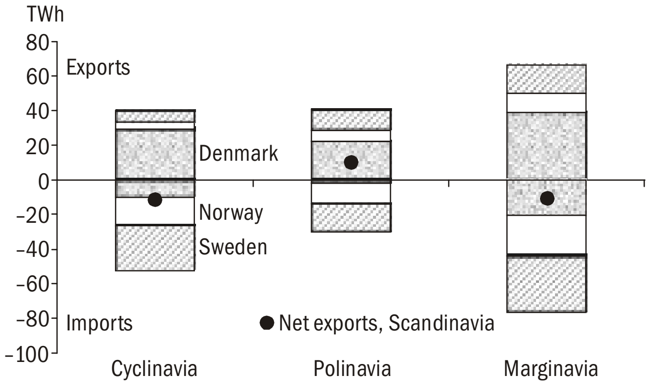


Figure 11 Trade patterns within and out of Scandinavia, 2010
Source ECON (2002b)

Insights

Scenarios are meant to gain insight into what drives changes and what interrelations and interdependencies exist between actors, interests, issues, and events in a complex world. Of the insights that this exercise has produced the following stand out.

Inconsistent and conflicting national policy agendas

- There is no common Scandinavian energy policy. On the contrary, significant national differences in priorities persist.
- Expectations are that the tensions between environment, efficiency, and security of supplies will increase.
- The Californian example illustrates that if inconsistencies between different policy targets and the unwillingness to make difficult choices persist over an extended period of time, the unique and successful Scandinavian market may easily fall apart.

Environmental policy interventions fitted to the market

- The common market makes it tempting for each country to act as a free rider: meeting the growth in consumption by imports but avoid taking responsibility for related emissions.
- Extensive direct interventions or a even moratorium on major commercial technologies are not consistent with a well-functioning market.
- An international system for tradable emission quotas represents the lowest abatement cost and goes well hand in hand with a regional electricity market.

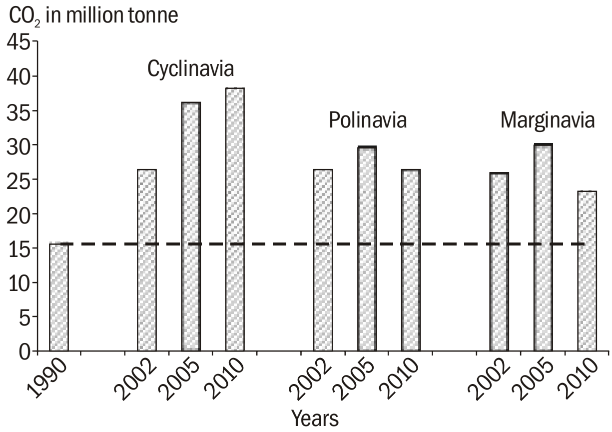


Figure 12 CO_2 emissions and off-sets
Source ECON (2002b)

Common market: need for coordination

- Increased coordination of competition policies is required to see to it that the highly competitive nature of the Scandinavian market is preserved.
- A shared Scandinavian responsibility for necessary peak or reserve capacity is needed and a mutual understanding of when and how to use this reserve so as not to undermine the market itself.

Adaptable and flexible regulatory regime

- The regulatory system needs to adapt and adjust to changes in the market place and policy agenda.
- An overall challenge to the regulatory system is not to get bogged down by details, and then to realize that costs of regulation may ultimately outweigh benefits.
- The need for flexibility must be weighed against the risks that instability imposes on commercial actors, which in the end are paid for by consumers in the form of high risk premiums in the market price.

A liberalized European gas market will support the Scandinavian power market

- A liquid spot and futuristic market for gas on the Continent will add flexibility and stability to the Scandinavian electricity market.

- If the existing pipeline system is regulated in a similar fashion to the electricity grid and a spot market develops on the Continent, gas can play an important role (even confined to the existing pipelines) and can provide the basis for a more extensive distribution system to be developed later.

If allowed to, the market works

- The Scandinavian competitive power market has delivered economic gains, and can continue to do so if the separation of roles between market and government is respected, and if policy and regulation conform to the function of the market.

Acknowledgements

We would like to acknowledge the work of several ECON professionals in developing the Scandinavian scenario project and report *Testing times: The Future of Scandinavian Electricity Industry*. We would particularly mention the substantial work done by Mark Davis, Orvika Rosnes, and Jan Arild Snoen. We are also grateful for the financial support and insights provided by the 22 participants of the project—ABB AS; Akershus Energi AS; Birka Kraft AB; BKK AS; The Association of Danish Energy Companies; The Confederation of Danish Industries; Dansk Olie og Naturgas - DONG A/S; E-CO Energi AS; Elsam A/S; The Norwegian Electricity Industry Association - EBL; Energi E2 A/S; Industrikraft Midt-Norge AS; Nord-Trøndelag Elektrisitetsverk; The Norwegian Water Resources and Energy Directorate; Skagerak Energi AS; Statkraft SF; Statnett SF; Svensk Energi - Swedenergy; The Confederation of Swedish Enterprises; The Swedish Energy Agency; Vattenfall AB; Østfold Energi AS.

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KESC's 2002 multi-year tariff determination: lessons for Pakistan and South Asia*

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Abstract

In preparation for privatization of the KESC (Karachi Electricity Supply Company), a state-owned vertically integrated electricity utility in Pakistan, the company requested that the regulatory body NEPRA (National Electric Power Regulatory Authority) grant a MYT (multi-year tariff). The new regulatory framework was proposed to assure the prospective investor would be allowed a reasonable period to recover the losses of the initial years of privatization before the base tariff is adjusted through a review. Thus permitting a much smaller initial price increase than would have been necessary if an MYT framework were not established.

The MYT – established by NEPRA in September 2002 – is essentially a consumer price index-X price-cap on the controllable costs of KESC while uncontrollable costs are considered on a pass-through basis. The assurance to earn reasonable returns and incentives to make investment are based on the investor's ability to meet efficiency targets, especially those relating to losses, set by NEPRA. The adoption of MYT for KESC is a radical shift from a rate of return regime to a performance-based regulation in the power

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sector of Pakistan. Similar MYT schemes are expected to be introduced for other distribution companies in the country.

This paper briefly reviews the most salient features of the MYT that has been established. As the first clear MYT in the energy sector in South Asia, there are lessons in this determination that other regulators and regulated companies should consider. Issues for consideration have also been noted.

Background on Karachi Electricity Supply Company

Before considering the specifics of the MYT (multi-year tariff), it is useful to consider the power sector in Pakistan and the characteristics of the company that had requested the determination.

The generation, T&D (transmission and distribution), and retail supply of electricity in Pakistan is presently undertaken by two vertically integrated public sector utilities – KESC (Karachi Electricity Supply Company) and the WAPDA (Water and Power Development Authority) – with significant contribution to generation from various private thermal IPPs (independent power producers).[3] WAPDA supplies power to all of Pakistan, except the metropolitan city of Karachi and some of its surrounding areas, which are supplied by KESC. Electricity in Pakistan is produced in various thermal (oil and gas 4590 MW; coal 150 MW), hydroelectric (5009 MW), and nuclear power plants (325 MW); however the generation by the KESC system is predominantly from thermal oil and gas power plants (Government of Pakistan 2003). The government has embarked upon a plan to restructure and deregulate the power sector by corporatizing and privatizing the state-owned electricity utilities. The power wing of WAPDA is in the final stages of being unbundled into a number of generation, T&D companies with a number of these companies earmarked for privatization in the near future. In contrast to WAPDA, KESC is planned to be divested as a vertically integrated utility. NEPRA (National Power Regulating Authority) was established in 1995 but was formally notified as an independent regulatory body for the electricity sector in Pakistan through an act passed in 1997.[4]

KESC is a vertically integrated electricity supply company undertaking all elements of the supply chain—generation, transmission, distribution, and retail supply.[5] It provides services to a customer base of 1.7 million, predominantly urban, customers in an area of about 6000/km^2 (square kilometres) in the Sindh and Baluchistan regions of Pakistan. The total population in its licensed area is estimated at well over 10 million. Initially established as a private company in 1913, the GoP (Government of

[3] As on June 2002, a little over one-third of the generating capacity was provided by IPPs—6332 MW out of a system total of 17 953 MW. (Government of Pakistan 2003).
[4] Copies of this act are available from the NEPRA web site (www.nepra.org.pk).
[5] KESC is in the process of acquiring separate licenses as per the requirements of the 1997 Act. Distribution and supply are treated as a single licensed activity.

Pakistan) took majority control of KESC in 1952 while leaving the company listed on Pakistan's three stock markets—Islamabad, Karachi, and Lahore. Presently, the government ownership in KESC is about 98% (Government of Pakistan 2003a). In 1999, there were about 12 500 employees of KESC.

While KESC owns and operates four power stations (total installed capacity of 1756 MW), it also purchases power from various other sources.[6] These include

- WAPDA which is the main electricity utility for the rest of Pakistan;
- state-owned companies such as Pakistan Steel and KANUPP (Karachi Nuclear Power Plant); and
- directly from two IPPs.

The load characteristics for KESC are provided in Table 1. KESC has been facing financial losses since 1996 due to high technical losses, pilferage, and high cost of power purchases. System losses have increased from 17% in 1985/86 to 40% in 2001/02 (Figure 1). Experiments with public sector management through non-traditional methods, including the induction of army personnel in uniform as top managers since 1999 did not show any signs of significant improvement. It is recognized that even substantial tariff increases may not increase revenues of KESC due to the possibility of customer shift to own-generation and increase in pilferage. Privatization is therefore considered by many as the better or, rather, the only way out.

Annexe 1 provides the information on the financial position of KESC while the issue of losses is discussed in more detail later in this paper.

Table 1 Load characteristics for Karachi Electricity Supply Company in 2000/01

Element	MW
Base demand (night-time)	831
Base demand (daytime)	1752
Peak demand	1860

Source Available at www.kesc.com.pk

[6] Two of the power stations are purely gas fired while the other two are oil- or gas-fired stations.

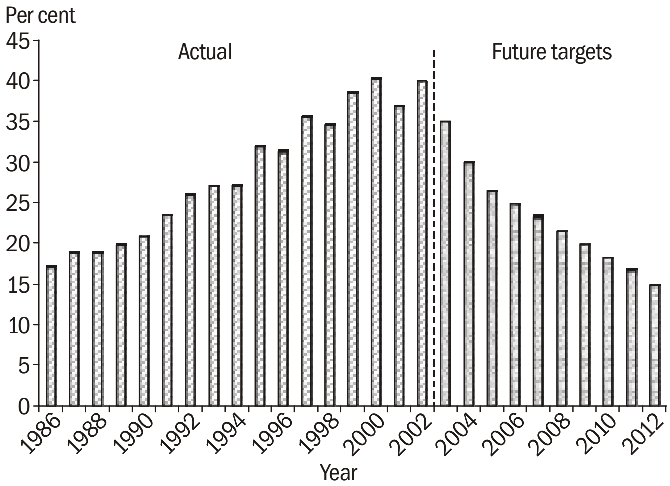


Figure 1 Karachi Electricity Supply Company's transmission and distribution losses
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

Part of the preparation for privatization of KESC has also been a financial restructuring aimed at clearing the accumulated losses of the business and making the forward-looking situation more acceptable. Consequently, during 2002 the GoP[7]

- converted 83.176 billion rupees of debt into equity; and
- wrote-off 57.202 billion rupees of capital to eliminate accumulated losses.

KESC is planned to be divested as a vertically integrated utility through the sale of 51%–74% of total equity with management control to a strategic buyer. Various target dates for privatization have been set and lapsed without success at least since 1997. Most recently, preliminary information to investors was issued in March 2002. Although several potential bidders expressed an interest, the process again lapsed. A further push for privatization was commenced in 2003 with a plan for completing the sale process early in 2004.

Expected privatization has raised the question about the certainty regarding tariff that the privatized KESC can charge its customers. The regulation of KESC to date has been on an ad hoc basis and driven by the compulsion to compensate KESC for its losses and inefficiencies.

[7] These actions were supported by a loan and technical assistance from the Asian Development Bank.

Regulation of KESC to date

NEPRA was established in January 1995 under an ordinance and was formally notified in January 1998 after the passing of the act in 1997. It finalized its Tariff Standards and Procedure Rules in December 1998. NEPRA's Tariff Rules allow formula-based tariff designed to be in place for more than a year. However, the regulation of KESC and WAPDA has been on an ad hoc basis, at least until the determination on MYT.

KESC filed its first petition in July 1999 for tariff decrease by 1.61%, which was approved by NEPRA in August 1999. KESC's second petition was submitted in August 2000 by the Ministry of Water and Power on behalf of KESC. This was for an automatic fuel adjustment formula to compensate KESC for changes in fuel price for KESC's own-generation or external sources of generation, in the form of adjustment to the average rate of sale. The adoption of automatic fuel adjustment formula was a significant step towards the formula-based MYT.

KESC's tariff was not precisely based on ROR (rate of return) regulation. In recent years, the actual cash outflows mostly exceeded the estimates because of higher actual losses as compared to targets and increased debt service liabilities. Consequently, NEPRA accepted that the inability of KESC's management to achieve the stipulated target of losses created the compulsion to resort to tariff increases or increased financial support from the government (in the form of subsidy or equity).

NEPRA's determination on MYT scheme

In May 2002, KESC filed a petition before NEPRA seeking an increase of 16% in the average customer tariff and approval of a formula-based MYT for the next 10 years. Prior to this submission, the GoP had requested NEPRA to consider the possibility of granting a MYT in March 2001.[8] The tariff was proposed to be reviewed after a period of 10 years and thereafter every five years. On 10 September 2002, NEPRA finalized the determination on KESC's submission and duly sent this to the Cabinet Secretary as per NEPRA's law (GoP has 15 days to assess the proposal and request any reviews). In its determination, NEPRA approved the MYT framework for KESC while making a

[8] The economic advantage of incentive- or performance-based regulation as compared to a cost of service or ROR regulation have been acknowledged in many countries, including the UK, US, Australia, and Abu Dhabi (UAE).

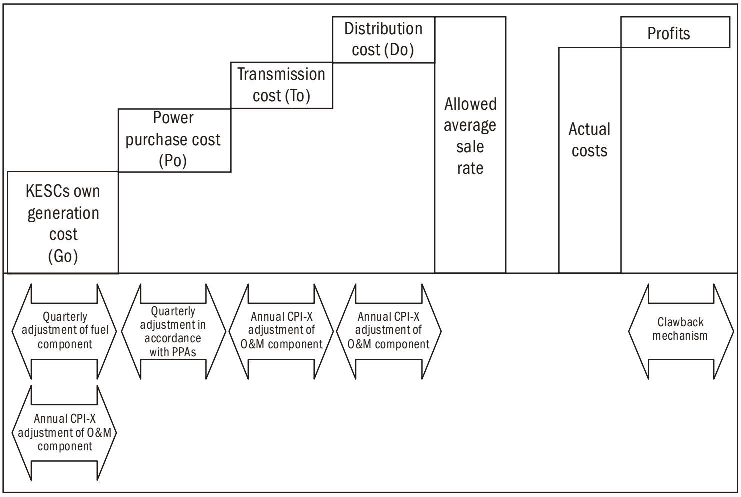
Table 2 Components of base tariff for Karachi Electricity Supply Company

	Average sale rate		*O&M component*	
Tariff component	Rs/kWh	% of total rate	Rs/kWh	% of total rate
Generation cost	2.43	51	0.10	2
Power purchase cost	1.48	31	NA	NA
Transmission cost	0.30	6	0.04	1
Distribution cost	0.53	11	0.32	7
Total	4.74	100	0.46	10

Rs – Pakistan rupees; kWh – kilowatt hours; NA – not applicable; O&M – operation and maintenance
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

number of changes to the proposal (Figure 2). The framework is described below.

1 The base tariff for MYT shall be the prevailing average customer tariff with an initial increase of 6.5%. Table 2 shows various components of the base tariff.
2 For the period up to the end of 7 years after privatization, the average sale rate shall be subject to the following adjustments.



CPI – consumer price index; O&M – operation and maintenance; PPA – power purchase aggrement
Figure 2 Multi-year tariff framework for regulation of Karachi Electricity Supply Company
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

Table 3 Percentage efficiency factor (X) for Karachi Electricity Supply Company

O&M component	*First 3 years*	*Next 4 years*
Generation cost	0	2
Transmission cost	0	2
Distribution cost	0	3

O&M – operation and maintenance
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

- Quarterly adjustment for variation in fuel component of KESC's own Go (generation costs) due to fuel price variations during the previous quarter.
- Quarterly adjustment for variation during the previous quarter in power Po (purchase cost) in accordance with the power purchase agreements with external sources (for inflation, exchange rate variation, fuel price variation, and so on).
- Yearly adjustment to O&M components of Go, To, and Do by applying the Pakistan CPI (consumer price index)-based inflation rate for the previous year less an efficiency factor X. Table 3 shows the factor X for various O&M (operation and maintenance) costs.

3 To avoid significant tariff fluctuations from one quarter to another, a number of measures shall apply to quarterly tariff adjustments. In particular, the quarterly tariff adjustment for fuel cost variation shall be limited up to a maximum of 2.5% and power purchase cost variation up to 1.5% (a quarterly limit of 4% in total). These limits shall apply separately such that the respective remaining burden or relief is transferred separately to the next quarter.

4 A CBM (clawback mechanism) shall apply whereby the profits accruing to KESC beyond a predetermined real ROR on asset (before tax and interest) in a certain year is shared with consumers through tariff reduction in the next year. The consumers' share increases as the profits increase beyond certain levels of ROR. Profits shall be shared between consumers and KESC if the equivalent ROR is
- in excess of 12% in the ratio of 25:75;
- in excess of 15% in the ratio of 50:50; and
- in excess of 18% in the ratio of 75:25.

Lack of data on which the scheme can be based is a problem that has been raised during discussions of MYT schemes elsewhere in South Asia. While NEPRA was forced to grapple with data issues, these were not seen as insurmountable. Further, the inclusion of a sharing system, discussed later in this paper, helps provide protection against abnormal profits arising from data mistakes.

Assessment of a new regulatory framework

According to NEPRA, the purpose of an MYT for KESC is to

- assure the incoming investor that the profits through reduction in technical losses, pilferage, and other efficiency measures over a certain period will be sufficient to compensate for the financial losses expected in the initial years;
- better serve the general public interest through economic efficiency, least cost service, and improved service quality; and
- bring more predictability in consumer tariffs by restricting the tariff adjustments to known indicators such as fuel price and inflation indices.

MYT has certain obvious strong advantages, like certainty for investors and customers, compared to the traditional ROR regulation. Since the approved MYT is based on the CPI-X price-cap, it also provides strong incentives for KESC to reduce losses and costs to earn and retain profits—although these are blunted to some extent by the CBM. While the principles are simple, the devil is in the details of how the framework is designed. The following sections briefly review the most salient features of the MYT that has been proposed, such as

- certainty and predictability of tariff for investors and customers,
- form of control and its associated incentives and risks,
- the determination of the allowed ROR,
- targets for loss reductions,
- O&M efficiency targets,
- process for pass-through of certain uncontrollable costs, and
- the time scale allowed for review of petition.

As the first clear MYT in the energy sector in South Asia, there are clearly lessons in this determination that other regulators and regulated companies should consider.

Certainty and predictability of tariff

It is often argued that privatization and regulatory strategies must work together. Regulatory uncertainty is usually considered as the major obstacle to successful privatization. Potential investors have the perception that the tariff-setting methodologies used by the regulatory agencies in Pakistan and other countries of the region lack certainty, as they fail to clearly define the price-path for the future that can assure the investor of recovery and earning a return on investment. However, the concern that has been mostly raised by possible investors is the uncertainty about the tariffs. The owner of a distribution company recently privatized (which then went into problems) in Orissa (India) considered MYT as imperative for resolving deep-rooted problems with the government and regulator. The World Bank has identified risky and weak regulatory frameworks for infrastructure (including electricity) in Pakistan as one of the four key reasons for the government's failure to improve the investment climate in the country (*Dawn* 2002).

The regulatory uncertainty is the inability of investors to predict with confidence what tariffs they will be allowed to charge after privatization. Investors' concern is not the levels of tariffs but their certainty. This is because the levels of tariffs, if certain, can be incorporated by the investors into the bid at the time of privatization. The value that an investor bids for the asset is simply the present value of the estimated net cash flows from the asset. Tariff being the source of revenue is the main input to this asset valuation exercise.

The investor may not be concerned much with losses that the company is presently suffering, as it indicates the potential for improvement and hence profits that the investor can make. However, this is to the extent that such losses are not beyond a company's or an investor's control.

In fact, regulatory certainty was the main reason for the government's proposal as well as the regulator's decision to adopt MYT for KESC. NEPRA forecasted that with MYT and KESC meeting its targets for system losses, KESC or the investor should be able to reduce its cumulative losses to zero during the next three years (2003–05) and to earn a reasonable accumulative overall return over 7 years (2003–09). This is shown in Figure 3 along with historical trends.

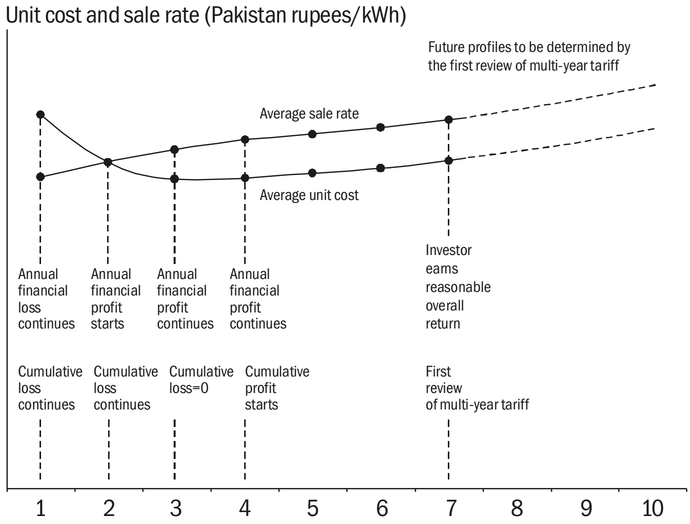


Figure 3 Expectations under the KESC multi-year tariff
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

The MYT will not only provide the certainty for investors in KESC but also to its customers. Customers also appreciate certainty about the price-path since it allows them to plan future expenditure. Having prices that vary significantly from year to year, let alone quarter to quarter, may make some budgeting decisions difficult for both industry and households. Providing certainty to customers through MYT price-path helps overcome this difficulty.

An uncertainty which remains with the regulation of KESC is the absence of any clear-cut commitment from NEPRA about the continuity of MYT framework in the event of a future price review. That is whether the incentive-based MYT will continue after 7 years from privatization, with new base tariff and X factors at the next review. In any case, the investor is likely to seek the required commitment from the government at the time of privatization, possibly backed by sovereign guarantees or some form of regulatory guarantee from a multilateral organization (Gupta, Lamech, Mazhar *et al.* 2002).

Form of control

While determining an MYT, the first question which the regulator needs to assess is what form should the proposed MYT take? There are four key characteristics that need to be considered.

Table 4 Scope of regulatory control

Element	*Scope of control*
Generation	O&M is subject to CPI-X incentives, other costs passed-through
Purchased power	Entirely a cost pass-through
Transmission	All costs subject to price-cap regulation, O&M is subject to CPI-X incentives
Distribution	All costs subject to price-cap regulation, O&M is subject to CPI-X incentives

O&M – operation and maintenance; CPI-X – cost price index-X
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

1 Scope of the control
2 Type of the main control: price-cap, revenue-cap or hybrid?
3 Risks associated with the allowed ROR
4 Period of control.

Scope of control

As discussed in the background, KESC undertakes all aspects of the electricity supply chain, as well as purchasing power from private and separately state-owned generators. As the main reforms in Pakistan have been aimed at unbundling the electricity supply company, KESC will be subjected to separate licences and each of the licensed businesses will be separately regulated.

So, there are four separate forms of control, as detailed in Table 4. The relative importance of each aspect is discussed later in this paper.

Type of cap

Once the scope of controls for various elements are set, the regulator then needs to answer that, for the three elements that are subject to incentive regulation, what form does this control take? Three options are available: price-caps, revenue-caps, and hybrids (combinations of the two).[9] In each case, NEPRA decided that a price-cap was an appropriate way of maximizing incentives for the operator to

- increase sales;

[9] The differences between these approaches and the implications for incentives and gaming are described in Alexander and Shugart (1999).

- improve the quality of service and over a period of time slow and even reverse the move to own-generation;
- reduce technical and non-technical losses; and
- reduce controllable costs.

Although the issue of controllable costs is also addressed through the direct determination of revenue, creating positive incentives was felt to be appropriate. NEPRA also stated that the creation of maximum incentives for KESC was appropriate owing to the starting point of having costs greater than revenues and NEPRA's desire to ensure a fair initial price increase.[10] Further, as discussed in the following section, mechanisms were also approved to share any significant upward benefits from the incentives with the customers through a CBM.

Rate of return risks

One by-product of price-caps is the possibility of earning significant levels of profit if the number of units sold increases rapidly (possibly due to unforeseen growth, faster than expected reductions in losses or gaming by the company at the time of setting the control). Some of these factors are under the control of the company, whereas others are not. Accordingly, to share some of the potential benefits from faster sales growth (and other actions that increase profitability) a sliding scale system is also proposed.

What is suggested and approved is an asymmetric sliding scale—the upside is shared but not the downside. It is also the case that different levels of sharing are suggested, so that incentives for the company are tapered. The proposed system is set out in Table 5.

Table 5 Real return on assets

Percentage of share	*<12%*	*12%–15%*	*15%–18%*	*>18%*
Consumers	0	25	50	75
Company	100	75	50	25

Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

[10] KESC had initially requested a price increase in excess of 40% (February 2002 petition) but had subsequently requested a lower increase of 16% (May 2002 petition) and was allowed 6.5% by NEPRA (September 2002 determination).

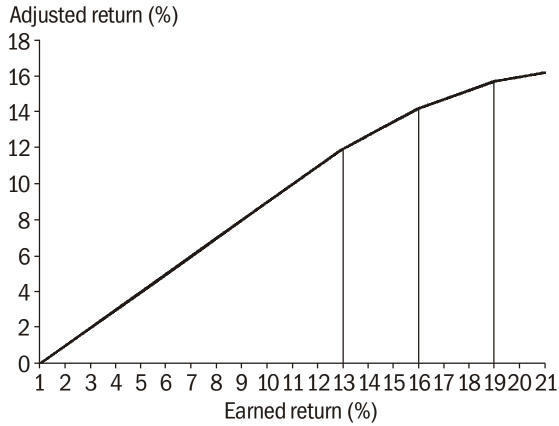


Figure 4 The impact of the sliding scale clawback mechanism on out-turn of profits
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

The base level of real return on assets (12%) was determined through a consideration of some market data. The real risk-free ROR in Pakistan is about 8% at the moment with an appropriate risk premium for the sector of 4%.

No attempt to measure the required ROR through models like the CAPM was presented in the tariff determination. However, some evidence on the basis for the determination of the 12% estimate was presented at a SAFIR workshop on Regional Pricing Strategy at a ater point, which is evaluated in the following section.

What does the sliding scale system imply for profitability (Figure 4)? There are also implications for the overall return earned by the company owing to the interaction of the adopted sliding scale system and the revenue-smoothing system. Of course, the MYT for KESC does not guarantee an ROR, however it assures KESC an ROR over a long term if it manages costs efficiently as envisaged. The expected RORs of 12%, 15%, and 18% are used to assess only the reasonability of the review period and limits of profit sharing in the CBM.

While there seems to be no strong possibility that KESC will earn any profit in the early years of MYT and any significant profits even in the later years, the CBM should be regarded as a good attempt to further reduce such possibility in view of the quality of cost data provided by KESC and to avoid any political or public relations damage to the regulatory framework in case the investor makes windfall profits. However, the design of CBM has two inherent flaws.

1 The mechanism is subject to manipulation. KESC can increase its regulatory asset base (and thus reduce actual ROR) by adjusting the timing of investment that is by bringing forward investment when the threshold ROR is expected to be exceeded so as to reduce the ROR by increasing the regulatory asset base.
2 Profit sharing is subject to discrete levels of RORs. That is, the same profit-sharing percentages apply to a wide range. For example, the sharing ratio 25:75 applies to returns in the entire range of 12%–15%. Ideally, the scheme should have been continuous or should have many small ranges, so that the customers' share of profits would have increased more rapidly with increase in return than what is allowed under the present design.

While the latter point will help overcome some of the perverse incentives for manipulation of the CBM system, it however also increases the complexity of the system. As such, any regulator needs to trade-off the complexity, with associated costs, and the incentives created for gaming the system.

Period of control

KESC in its submission to NEPRA requested a 10-year price control period. NEPRA, in its assessment of the proposed length of the control, took the following issues into account.

- Most international evidence on the length of price controls is between 3 and 5 years; and
- KESC, unless significant initial price increases are allowed, would continue to make losses for several years.

Due to the latter point, NEPRA chose a pragmatic approach: trying to weigh future profits against the initial losses, while being aware of GoP's plans for privatization. Given the 12% allowed real ROR, it was found that a zero or positive NPV (net present value) was possible after 7 years. So, a 7-year price control period has been approved by NEPRA. NEPRA's determination, however, does not contain the actual analysis or calculations leading to the 7-year conclusion. This may raise the issue of transparency in the regulatory process making it difficult for interested parties to replicate such calculations and convince themselves of the justification of a 7-year duration.

Clearly, choosing a price control period that is long by international standards has the following implications.

- The potential for significant cost shocks to occur
- The potential for unanticipated demand growth to lead to significant abnormal profits; and
- Unanticipated shocks affecting investment requirements that could have a significant impact on the company by requiring it to undertake investment not anticipated when the price control was set and consequently not rewarded during the life of the price control.

The regulatory system should be designed in a manner to help control some of the implications. For example,

- the profit-sharing system should protect against abnormal profits becoming an issue; and
- the cost pass-through elements for uncontrollable costs should protect against unanticipated shocks.

However, it is not clear that the investment issue will be sufficiently captured through the proposed system. This could prove to be an important point. For example, KESC's generation plants and networks require massive investments. However, the base tariff does not incorporate any investment plan nor does the MYT framework provide any explicit assurance for recovery of any investment (for example, there is no discussion of how an asset base will be calculated and updated). In other countries where CPI-X (or even ROR) regulation is in vogue, the utility is provided with an allowance for its prudent investment and any investment plan underlying such allowance is carefully monitored.

NEPRA has argued that the approved MYT provides an incentive for investment in capacity expansion by allowing KESC to increase its revenue through increase in consumer base and increase in sales or consumer without any restriction. Investment in system refurbishment will reduce losses and consequently generation costs and hence will be rewarded as increased profits. If the reduction in losses exceeds the efficiency targets, the company will earn more profits. With a larger asset base (which would avoid triggering of CBM), KESC will be able to retain most of the resulting profits.

However, it is not obvious that the benefits of investment (increased sales and profits through capacity expansion and reduction in losses and generation costs) will be enough to recover the actual investment with reasonable returns. As far as the profit sharing through CBM is concerned, as noted above, it may provide incentives to the company to manipulate its ROR to avoid or reduce any profit sharing with the customer, rather than to provide direct incentives for investment. It could be argued that the investor will take into account investment requirements while submitting its bid at the time of privatization rather than to make investment in response to any indirect incentive of MYT.

A further issue that should be considered when thinking about the period of the control is the linkage with privatization that NEPRA has created. While NEPRA had approved the MYT for a period of 7 years commencing from the date when KESC is privatized, it had to come into effect prior to the privatization that was expected to be completed in the calendar year 2002. Although such an application may be desirable for certainty, better efficiency incentives, and a successful transition phase, it must be recognized that the continuing public ownership may ultimately place a limit on the efficiency improvements that can be achieved.

A key issue relevant to the duration is raised, 'What will happen if privatization is delayed considerably?' If KESC is not privatized, say, for 2 to 3 years, the MYT period will run for about 9 to 10 years which may have some undesirable outcomes. In particular, a state-owned KESC will be subject to the MYT principally designed for a privatized KESC and to performance targets that have not been achieved so far. KESC may therefore ask for revision of approved MYT or for additional tariff increases if the privatization is significantly delayed.

Efforts are under way again to hasten the progress of privatization. As noted earlier, the existing privatization plan is based on a sale in early 2004. As such, NEPRA has continued with the application of the MYT even though it does have the option of switching to a more prescriptive approach, as set out in the original determination. While this is laudable as per the points set out above, there does have to be some concern about applying an incentive-based approach to a company whose corporate governance is such that if does not necessarily respond to standard corporate goals. This has been an issue in India where several regulators, most recently the Uttar Pradesh Electricity Regulatory Commission, have commented on the problems of creating effective incentives for state-owned companies (UPERC 2003).

With hindsight, NEPRA could have set a target date for privatization of KESC, say 2 years and then have had two separate MYTs: one MYT for up to 2 years when KESC is not privatized and another MYT for 5 years after privatization. The former MYT could be revised if KESC is not privatized in 2 years based on the circumstances and latest information. This approach would have capped the total duration to 7 years and addressed other concerns. Presently, the total duration of the approved MYT could be interpreted as open ended, although that does not seem to be the approach being adopted by NEPRA.

Determination of the allowed rate of return

As noted earlier, the 12% of allowed ROR (Alexander [forthcoming]) was recently explained in a presentation by one of the members of NEPRA. It was built up accordingly

Cost of equity	
Element	Estimate
(1) Market return	11%
(2) Risk-free rate	8%
(3) Market risk premium	3%
(4) Equity beta (based on US data)	0.66
(5) Country risk	2%
(a) Cost of equity	(2) + [(4) x (3)] + (5) = 12%
Cost of debt	
(b) Average cost of debt	12.4%
Capital structure	
(c) Debt	55%
(d) Equity	45%
Cost of capital	
Weighted average cost of capital	[(a) x (d)] + [(b) x (c)] = 12.2%

Undertaking a full assessment of the applicability of this number is beyond the scope of this paper. However, some initial observations can be made.

Methodology

Within the standard WACC (weighted average cost of capital) approach adopted by NEPRA, three methodological issues can be raised.

1 Mixing of forward-looking and backward-looking approaches;
2 clarity about what is being measured; and
3 the need to make adjustments to the beta value.

The approach adopted by NEPRA for the cost of equity is the standard CAPM. This is a forward-looking approach to estimate the cost of equity and is employed by many regulators in developed and developing countries. However, the approach adopted for the cost of debt is a backward-looking assessment of the rates at which the company has been able to borrow money: this is a more traditional approach to the cost of debt, especially when the cost pass-through of interest is allowed. However, the backward-looking cost of debt approach is inconsistent with the cost of equity approach when combined like this in the WACC. Forward-looking costs of debt are likely to be significantly lower than those at which the company has borrowed in the past since there has been a significant shift downwards in the risk-free rate.

While there may be some circumstances in which it is appropriate to view interest payments as a cost pass-through item, it would be more appropriate to keep this as a separate item and to focus on a cost of equity approach. Further work on the cost of debt would seem appropriate.

Linked to the above issue is the one of exactly what is being estimated. There are many different basis on which WACC can be calculated. These depend on the view as to whether it is the position of the company being considered or that of the investor and whether returns are measured pre- or post-tax (Alexander [forthcoming]). The determination of exactly what is being measured is important since it affects how other elements of the cost-flow are being incorporated into the revenue requirement. For example, if post-tax figures are being employed then tax payments need to be included as a separate cash-flow item—that is not necessary if a pre-tax figure is being utilized. Clarity about this will allow the consistency of the revenue requirement calculation to be determined.

Equity betas are a reflection of two factors:

- the underlying business risk, referred to as the asset beta; and
- the capital structure of the company.

In relation to the equity beta – the measure of the relative risk of the business – there are two adjustments that should have been considered

- the form of regime employed; and
- the capital and tax structures of the company relative to the comparator.

Business risk is, itself, a function of several factors. One of these is the type of regulatory regime—different types of regime leave the operator more or less exposed to general economic conditions. As such, when using comparative data to establish an estimate of the business risk, it is important to ensure that either companies facing similar regime types are used, or that an allowance is made for the regime type. In the case of KESC, the US data was employed to establish the business risk.

No single type of regime is used in the US, rather different states use different approaches ranging from the traditional ROR regulation to earnings-sharing (profit-sharing), and price-caps (Williamson 2001). As such, clarity about the exact comparator used and whether the regime was comparable to that being proposed for Karachi is necessary to establish whether the right comparator was being used.

Secondly, as noted above, the capital structure of a company also has an impact on the equity beta value. So, an asset beta is the better starting point since this can then be adjusted to the capital structure proposed for the company being regulated rather than just using the capital structure of the comparator. Again, clarity about the comparators utilized would help determine if the approach was appropriate.[11]

Estimates

While much of the methodology employed is standard across regulators, the estimates employed need further analysis. For example, the market risk premium is an estimate of the additional average annual return required to hold a basket of all assets rather than just the risk-free asset. Traditional values for this in developed countries have focused between 6% and 9% while more recent evidence has suggested values between 3% and 4%, which might be more appropriate (Jenkinson 1998). So, the proposal by NEPRA to employ a value of 3% would suggest that either a relatively aggressive estimate has been taken, or that there is a strong belief that the international capital markets are

[11] There are also arguments about needing to adjust for taxation when de-leveraging an equity beta value. This is discussed in Alexander (forthcoming).

efficient. It may be that a higher figure could be appropriate for Pakistan for which the state of the Pakistan market would need to be evaluated.

Further, the use of a country's risk premium is a good way to correct the fact that US data is primarily being employed to calculate the risk premium. However, a 2% premium would seem to be low for Pakistan. Evidence on comparable borrowing rates for countries with different ratings is provided in a range of journals including the *Financial Times*. While data are not specifically provided for Pakistan, it is possible to consider premia paid by comparable countries. This evidence would bolster the justification for the numbers used. For example, in December 2003 the Philippines Government was paying a premium of 1.18% more than the US Government to borrow money while the Brazilian Government was paying 4.67% (*Financial Times* 2003). This information can be collected from various sources and can be considered as an input to determining an appropriate country-risk premium.

Comparable estimates for other infrastructure providers

A final source of information, which can help establish the appropriateness of a regulatory estimate, are the rates allowed for other companies. One example here is the fact that OGRA, the gas regulator, allows gas T&D companies to earn ROR between 17% and 17.5%. The basis for these estimates is less clear that is the basis on which the estimates of 17% and 17.5% were established, but the fact that these figures are significantly higher than those allowed by NEPRA should signal that further analysis is required.

Overall, NEPRA has taken a major step forward by setting out calculations that it employed when deriving the 12% allowed ROR figure. While there are some issues about the methodology and the estimates involved, these issues can be refined.

Losses

While an incentive-based system has been established for O&M costs of various elements of the company, however the possibility of additional profits arising from outperforming these incentives is limited.

Like the rest of South Asia, the largest 'controllable' cost that a company faces is related to losses—losses that are outside the scope of the O&M incentive scheme but captured or incentivized within the price-caps for different elements. If KESC can reduce its losses, it will earn additional profits to the extent allowed by the CBM.

Figure 1 illustrates the evidence on losses for KESC since the mid-1980s. Although some periods of slight improvement have been seen, most recently in 2001, the overall trend has been for the situation to become worse.

NEPRA in the determination make two specific comments about losses

- losses for the financial years 2003 and 2004 should be 35% and 30%, respectively; and
- that within a 10-year period the operator should be able to reduce losses to 15%.

This was supplemented by some further information in the financial projections suggesting that

- auxiliary consumption (the own use of power by the generating plant) would drop from 6.1% to 5.8% over 3 years; and
- the forecast of T&D losses for 2005 was 26.5%, suggesting a further 3.5% point improvement from 2004.

Since no specific details are given about how this long-term decline should be phased, the diagram assumes a constant rate of improvement to reach the 15% from the 2005 figure.

How possible is a 10% improvement in 2 years? It is clear that concerted efforts, as seen occasionally, since the mid-1990s can lead to improvements above 2%–3%. But these improvements have never been sustainable.

It is also not clear as to where the majority of the losses lie—technical or commercial? Owing to the poor financial position of KESC over the past few years, there has been a significant reduction in the investment programme. Consequently, it is not possible to determine whether the rapid deterioration in the losses is due to technical issues, linked to the reduction in investment, or the more general commercial problems raised by law and order issues.

What is clear is that there is an issue of commercial losses in Pakistan, and if previous experience is anything to go by then a significant element of the KESC losses will be commercial. As such, it ought to be possible for reductions to be made in a timely manner, although it will also be important to ensure that these savings are then cemented rather than being lost in a matter of years.[12]

Efficiency

When thinking about the main aspects of efficiency, apart from the question of loss addressed above, there are three things worth considering:

1. How important are the O&M costs?
2. What efficiency factors are proposed and how were they determined?
3. What is the planned evolution of real O&M costs?

Importance of O&M costs

The cost structure of the existing electricity system and the relative importance of O&M costs are given in Table 2. It shows that although O&M costs account for only about 10% of the total cost of delivered electricity, they account for over 60% of the distribution costs.

Efficiency factors

KESC accepted the need for efficiency factors and made the following proposal. They also suggested that a 0 X factor be adopted for the first 3 years of the price control (Table 6).

NEPRA decided against linking the X factor to the inflation rate, believing that the factors determining X were independent of the inflation rate. Rather, they considered

- the potential impact of too aggressive X factors on quality of service;

Table 6 KESC (Karachi Electricity Supply Company)'s proposed X factors

Rate of inflation (%)	*X factor* (%)
<0	1.0
0 to 5	2.0
5 to 8	2.5
>8	3.0

Source KESC petition, May 2003

[12] KESC is also likely to come under further pressure from WAPDA to ensure that the losses are constrained. KESC has been a major source of receivables for WAPDA and given the increasingly tight budget constraints imposed by GoP there will be pressure to ensure that this is not the case in the future!

- the need to ensure that the X factor captured the industry efficiency rather than company specific;
- the fact that T&D losses are the most significant efficiency/cost factor; and
- incentives for investment to promote capacity expansion should be ensured.

Given these factors, X factors in Table 3 have been proposed for the O&M costs of the different elements of the industry. For 4 to 7 years they provide an overall target of about 2.7% of controllable costs. Figure 5 illustrates the evolution of the controllable costs over the lifetime of the control.

Figure 5 shows that NEPRA has set efficiency factors (X) at zero for the first 3 years and then 2%–3% for subsequent years. While the zero efficiency factor for an early period of MYT is adopted in other countries, 2%–3% of X-factors for subsequent years are on the lower end of the X factors adopted by other regulators—this also does not take into account the significant cut in base tariff made by regulators at every 4 to 5 years. For example, the UK electricity regulator's second price controls for distribution companies stipulated one-time price cuts in the range of 11%–17% for an X factor of 2%. The next price controls resulted in more significant price cuts (18%–35%) with an X factor of 3%. In Victoria (Australia), the regulator set X factors in the second price controls for distribution costs in the

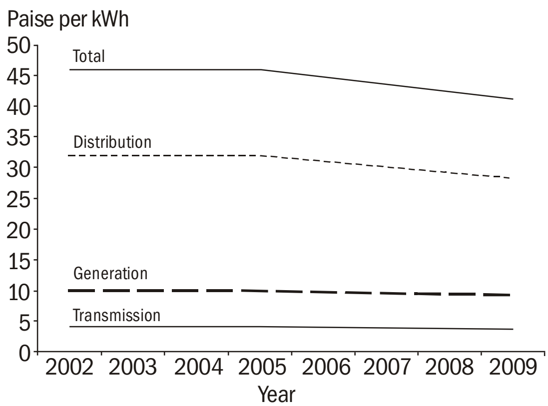


Figure 5 The evolution of operation and maintenance costs over the life of the proposed price control
Source Tariff Determination in Case No. NEPRA/TRF-14/KESC 2002

Table 7 Annual real unit operating cost reductions in UK utilities since privatization

	1992	*1993*	*1994*	*1995*	*1996*	*1997*	*1998*	*CAGR*
Electricity transmission	15.6	–6.1	–15.0	–14.4	–7.0	–6.4	–11.1	–6.5
Electricity distribution	–3.3	–1.5	1.8	–5.8	–12.5	–14.4	–8.9	–6.8

CAGR – Compound Annual Growth Rate
Source Adapted from ORR (1999)

range of 12% and 22% in 2001 and thereafter 1% each year from 2002 to 2005.

Further, the UK experience shows that the actual efficiency improvements made by companies have been well above those assumed by the regulators in setting price controls. Table 7 shows the annual real unit operating cost reductions in the UK electricity utilities since privatization. The average annual reduction is about 6.5%–6.8% (Estache, Guasch, and Trujillo 2003).[13] These improvements are calculated after taking into account of the effect on costs of changes in output levels and the level of service quality, and so can be taken to represent 'underlying' efficiency improvements. The efficiency improvements actually made by the utilities are more relevant than the efficiency improvements assumed, as the former indicate the extent of efficiency improvements that can actually be realized.

Though the above range indicates the potential of cost reduction by privatization and management and technological developments, the extent of cost reduction that can actually be achieved depends – among other things – on the environment a utility operates. However, it may be argued that KESC's present situation indicates a greater extent of efficiency improvements that can be achieved compared to the UK utilities. Although it is worth noting that the X factors for KESC are in addition to the system loss reduction targets set by the regulator.

In general, the establishment of a non-zero X factor for KESC should be considered as a good step in the right direction. CPI-X price-caps can successfully work for state-owned utilities; however it is recognized that the continuing public ownership of an entity may ultimately place a limit on the efficiency improvements that can be achieved.

[13] Evidence from Latin America is also available.

Evolution

Given these X factors and the relative costs of each segment of the industry, it is possible to determine the evolution of O&M costs over the life of the price control (Figure 5). If the total costs of electricity supply in Karachi are considered, the X factors amount to an effective 0.15% of an annual efficiency target (or an annual efficiency target of 1.5% of O&M costs) over the life of the price control.

Cost pass-through

As mentioned when discussing the form of price control, the vast bulk of costs are treated on a cost pass-through basis. This section considers four elements of cost pass-through:

1 the fuel price adjustment formula;
2 the PPA (power purchase agreement) adjustment formula;
3 the process by which the adjustments are made; and
4 the cap to the maximum allowed change in any one quarter.

Fuel price adjustment

For own-generation, the largest uncontrollable cost is fuel. A fuel cost pass-through system had been initiated in 2000/01 for the Pakistan electricity sector but this has not been successful (primarily due to process issues described below). In the KESC determination, a new version of the adjustment mechanism is proposed which also separates power purchase adjustments from pure fuel cost changes.

For the fuel cost pass-through, consider the following example.

Consider five quarters

$Q_{0,1}$ (actual), $Q_{0,2}$, $Q_{0,3}$, $Q_{0,4}$, $Q_{1,1}$

A change in fuel costs during $Q_{0,1}$

Then estimate the impact over the actual quarter ($Q_{0,1}$) and the next three quarters ($Q_{0,2}$ to $Q_{0,4}$)

Assessment of costs is based on the actual price for current quarter and this new price as the forecast for the next three quarters (done in paise per kWh). Using the actual generation and forecast generation, the revenue impact can be determined.

Revenue is then recovered as a paise per kWh adjustment over the next four quarters ($Q_{0,2}$ to $Q_{1,1}$), thus smoothing the impact by

- allowing for seasonal variations in production/use of fuel; and
- not having to recover the current quarters higher costs immediately but spreading it over the following four quarters.

So, this approach dampens volatility but could become extremely messy if frequent fuel cost changes occur.

Power purchase

Power purchase costs from IPPs are basically treated the same way as fuel costs (a consideration of the change for the current quarter being assessed over the next three quarters and then recovered over the next year) but it is all costs rather than just fuel costs.

Process

As noted above, one of the issues with the fuel cost pass-through over the past year or two has been the process by which it is applied. The GoP had requested NEPRA to find an *automatic* system for allowing quarterly changes in fuel costs. NEPRA contends that the 1997 act does not allow for automatic changes in tariffs, any change must be notified to the GoP and placed in the official Gazette.

To facilitate the timely implementation of the pass-through mechanism, NEPRA provided a prescribed form for any request. This simplifies the process and ensures that the evaluation does not become as time consuming as a price determination.

In an attempt to clarify how NEPRA believes this system should work, the following are given below.

- The company is allowed to request an automatic change each quarter, with the dates for the quarters clearly set.
- Within 4 days of receipt of request, KESC will be allowed to implement the change (subject to having to refund any difference if so determined).
- As quickly as possible, and no later than one month after receiving the request, NEPRA will finalize the determination and submit to the GoP.

In view of the apprehension that KESC may not be prompt to request for an adjustment in case of an expected decrease in tariff in a relevant period (which would be unfair to customers), then NEPRA shall take a *suo moto* action based on quarterly or yearly adjustments due to fuel price, power purchase, and profit for clawback.

Cap to quarterly changes

Under the existing fuel cost pass-through system, a maximum quarterly change of 3% is permissible. KESC proposed that this be changed to 5%.

NEPRA reviewed the issues and determined that the following maximum 4% cap (with carry-over of any under recovery but no interest cost allowance) be established using

- a cap of 2.5% of the final retail tariff for the fuel cost adjustment; and
- a cap of 1.5% of the final retail tariff for the power purchase adjustment.

It is also proposed that any failure to meet targets of losses should not benefit from the cost pass-through protection. Thus, investigation to consider losses and additional sales will be required to ensure that the protection is not provided.

However, the investor needs to assess the risks associated with the limits that the regulator put on the quarterly adjustments to the tariff. The furnace oil and gas prices have increased on average by about 15% and 8% per annum, respectively, over the past 5–6 years. Over a longer term (1993–2002), such average annual increases are about 18% and 12%, respectively. Assuming that the fuel price variation would be in the range of 8%–18% per annum over the control period (which translates into quarterly variation of 2%–4%), the quarterly adjustment to the fuel component of Go which makes about 50% of average sales rate will result in about 1%–2% increase in average sales rate and, hence being below the limit of 2.5%, be allowed.

However, if the fuel price increase is significantly high (like the 70% per annum increase in 1996/97), the investor will not be able to pass on full fuel cost increases for sometime. Any cost of borrowing or working capital to support increases needs to be assessed carefully as the MYT framework for KESC does not allow any interest to be applied on late recovery of fuel costs (and power purchase costs) from the customers.

Equally important is the issue of customer affordability. The success of MYT depends on whether the customer will be able to afford frequent and significant tariff rises, and whether the political government will let such a framework function as envisaged. Some of the automatic fuel cost adjustments over the past year have not been as timely as expected, partly owing to government concerns about the implications of such increases.

In the rare case, a maximum of 4% quarterly tariff adjustment for fuel and power purchase costs (which translates into 17% of annual tariff increase) and 0.3%–1.3% of annual tariff adjustment for CPI-X indexation (based on the actual inflation of 2.7%-13% per annum during the past ten years) may be required. This translates into an overall annual increase in tariff by 17.3%–18.3%, the affordability of such increases has to be questioned whether borne directly by consumers or indirectly through taxation if the Government chooses to subsidize the tariff.

Privatization

Finally, NEPRA made some comments about the application of the MYT scheme being linked to the privatization efforts. In principle, the MYT is only enacted once privatization has occurred since the whole rationale is related to providing certainty and incentives for a private operator. If this fails to materialize, some additional directions are provided by NEPRA relating to issues such as the size of receivables, rehabilitation of KESC's own-generation facilities, and so on. KESC would then be able to file further tariff petitions as it had done previously. However, as noted above, the system is effectively being utilized and a price increase as per the MYT was processed during the summer of 2003.

While it is not explicitly stated, NEPRA is basically following the view that it is not possible to create incentives for state-owned enterprises. In the vast majority of cases this would appear to be an appropriate assumption (Irwin and Yamamoto 2003).

Implementation processes and time scales

NEPRA's tariff rules provide formula-based tariff designed to be in place for more than one year. These rules set out the standards and criteria to be followed while NEPRA examines and decides on a tariff petition. The rules also clearly lay down the procedure for dealing with a petition from the date of filing of the petition till the final determination of NEPRA and decisions on any review motions or reconsideration request by the government. NEPRA has to decide on tariff petition within 6 months of the filing of a petition. In practice, more time is required for a comprehensive review of tariff if it is to be in place for a long time (5 to 7 years). Regulators in other countries where MYT is in operation conduct thorough consultations over an 18 to 24 month period and publish a number of consultation papers before arriving at any decision. NEPRA needs to assess this aspect of its procedure, and ensure more transparency and objective consultation with interested parties.

Conclusion

NEPRA's determination of a MYT for KESC reflects the first serious attempt in South Asia to create a comprehensive MYT system for an electricity company (Agarwal, Alexander, and Tenenbaum 2003).[14] There are many positive aspects to this which other regulators in the region and internationally can learn from. These include

- the reasoning for the length of the control period and certainty, incentives and risks for prospective investor;
- the building of elements of a regime to control for shocks, abnormal profit concerns and so on; and
- the process solutions for automated quarterly adjustments.

There are, however, some areas that require further investigation. These include, but are not limited to

- the treatment of, and incentives for, investment: no explicit rules for the regulatory asset base, inclusion of investment, treatment at the end of the period are provided;
- whether the 12% real ROR is sufficient;
- lack of details in the determination on various aspects for example, ROR, appropriateness of duration; and
- inadequate time (6 months) allowed by NEPRA tariff rules for determination on such a long-term MYT—international regulatory practice on CPI-X price review suggests 1–2 years.

While the last point need not be an issue if the sale price is allowed to be below the nominal value of the equity, it would be an issue for future reviews.

[14] The Delhi privatization which occurred in the summer of 2002 involves some elements of an MYT system, but is not a comprehensive determination.

Annexe 1 KESC's financial position[15]

Profit and loss statement

Table shows the financial results of the Corporation for the last three financial years ending 30 June 2001 and for the 9 months ending March 2001 and 2002.

	Year ended 30 June			*Nine months ended 31 March*	
Description	*1999 Audited*	*2000 Audited*	*2001 Audited*	*2001 Unaudited*	*2002 Unaudited*
Revenue (rupees in million)					
Energy sales	23 285	25 035	28 118	20 278	21 875
Other income	496	1 007	722	404	554
Total revenue	23 781	26 042	28 840	20 682	22 429
Expenditure (rupees in million)					
Cost of fuel consumed	9 312	13 916	17 717	12 390	13 338
Electricity purchased	11 401	12 202	13 780	10 095	8 821
Depreciation and other expenses	7 160	7 141	7 704	5 778	5 635
Loss before interest	(4 092)	(7 217)	(10 361)	(7 581)	(5 365)
Interest	3 273	5 569	5 840	4 380	6 598
	3 273	5 569	5 840	4 380	6 598
Loss before tax	(7 365)	(12 787)	(16 201)	(11 961)	(11 963)
Tax	119	130	152	–	–
Loss after tax	(7 483)	(12 917)	(16 353)	(11 961)	(11 963)
Transmission and distribution losses (%)	38.6	40.2	36.8	35.0	39.8
Average tariff (Rs)	3.799	3.894	4.061	3.898	4.410

Key points

- The loss before interest grew rapidly during the three-year period to 30 June 2001, primarily as a result of fuel price increase not passed on to customers in full.
- Over the two years and nine months to 31 March 2002, the Corporation's revenues have not even covered the cost of fuel and purchased power.

[15] This information is taken from Section 4 of the May 2002 tariff petition filed by KESC.

- The poor financial performance of the Corporation reflects the continuing high level of energy losses suffered by the company.
- In the nine months to 31 March 2002, the loss before interest showed an improvement relative to the prior year, mainly on account of
  - lower power purchases as a result of increased availability of KESC generation,
  - lower average fuel prices, and
  - tariff increases allowed by NEPRA.
- The growth in loss before and after tax in the three-year period was even more dramatic, as a result of the growing interest burden from financing the continuing losses.
- In the financial year 2002/03, the improvement in losses before interest was more than offset by the continued increase in interest costs.

Balance sheet

The balance sheets at 30 June 1999, 2000, and 2001 and at 31 March 2002 are summarized below.

	June			*March*
Description (rupees in million)	*1999* *Audited*	*2000* *Audited*	*2001* *Audited*	*2002* *Unaudited*
Share capital and reserves	10 714	10 714	10 711	28 546
Accumulated losses - Net	(19 319)	(32 236)	(48 589)	(60 552)
	(8 605)	(21 523)	(37 878)	(32 006)
Long term borrowings (> 1 year)	44 457	43 347	48 207	34 393
Other long term liabilities	4 657	5 247	6 103	6 745
Long term borrowings (<1 year)	2 764	3 723	8 096	7 401
Short term borrowings	7 931	8 345	15 041	22 107
Other current liabilities	18 406	27 035	27 668	26 780
	69 610	66 174	67 237	65 420
Tangible fixed assets	49 751	49 232	47 865	46 575
Other long term assets	392	296	263	189
Current assets	19 467	16 646	19 109	18 656
	69 610	66 174	67 237	65 420

Key points

- Dramatic growth in borrowings to finance growing losses.
- KESC has had to rely on the GoP to keep the Company afloat. The vast majority of KESC's borrowings are provided by, or guaranteed by, the GoP.
- On 28 February 2002, borrowings and liabilities were reduced by 17.8 billion rupees by way of a debt : equity swap.
- Tangible fixed assets have declined over the period, most particularly during the year ending 30 June 2001, reflecting the very low level of capital investment during recent years. Because of funding constraints, the capital expenditure programme has been severely curtailed.

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Information for authors

An international biannual journal, the International Journal of Regulation and Governance has been published by The Energy and Resources Institute, New Delhi.

Submissions

Three good-quality hard copies of the manuscripts have to be submitted to the Editor. Manuscripts can be submitted electronically also.

Presentation of manuscripts

Manuscripts must be in English and the length of original articles should not exceed 6000 words. They must be typed on one side, only on international standard A4 size paper, with a left-hand margin of 40 mm. The main text should be double-spaced with headings and sub-headings clearly indicated and placed on the left-hand side of the text. All tables, figures, and equations should be numbered with Arabic numerals and the measurements should be given in metric (SI) units. The manuscript should be arranged in the order given below.

1 Short title (10 words is the desired maximum length), subtitle (if desired)
2 Author's name, affiliation, full postal address, and e-mail, telephone, and fax numbers (respective affiliations and addresses for co-authors should also be clearly indicated)
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4 Main body of the text, suitably divided under headings
5 Acknowledgements
6 References
7 Appendices/annexures (each on a separate sheet)
8 Tables (each on a separate sheet)
9 Figures (each on a separate sheet)

Shorter items

The following short items are also welcome and must be typed in the same way as major papers.

- Viewpoints (research notes and short communications) and case studies (maximum 1500 words)
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References

In the text, the surname of the author(s) followed by the year of publication of the reference is to be given, e.g. (Hall 1993). Where there are several publications by the same author(s) in the same year, use notations '1993a', '1993b', etc. Up to three authors can be mentioned in text references; four or more authors should be shortened to the first three authors' names followed by et al. References must be listed alphabetically at the end of the paper (double spaced) and should conform to the following style.

For journals: Davis G R. 1990. **Energy for planet earth**. *Scientific American* **263**(3): 55–62.
For books: Carmichael J B and Strzepek K M. 1987. *Industrial Water Use and Treatment Practices*. London: Cassell Tycooly.
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For grey literature: Togeby M and Jacobsen U. 1996. How conflicting goals concerning environment and transport influence the policy process? Paper presented at the Conference on Transport, Energy and Environment, 3–4 October, Helsingor, Denmark.

Footnotes

Footnotes should be minimized, and where unavoidable, should be indicated in the text by superior Arabic numerals, which run consecutively through the paper. They should be grouped in order of appearance at the bottom of the concerned page in numerical order and must be double-spaced.

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