This Report was edited by Eugene McCarthy and Felix Martin. The Energy, Mining, and Telecommunications Sector Board
served as the steering committee. The editors are very grateful to the following external contributors for their insightful sug-
gestions and rich contributions: Carlos Suarez, Anthony Churchill, François Ailleret, Bernard Montfort, Lee Schipper, Mike
Bess, Mishiro Masaaki, Youba Sokona, Gerry Leach, and Alain Streicher and Jean-Louis Poirier of PHB Hagler Bailly, Inc.
Within the World Bank Group, the editors would like to thank the following people for their generous help: Yves Albouy, Shane
Streifel, Karl Georg Jechoutek, Laszlo Lovei, Denis Clarke, Nelson De Franco, Kyran O’Sullivan, Mangesh Hoskote, Ranjit
Lamech, Anil Malhotra, Mark Tomlinson, Dominique Lallement, Henri Bretaudeau, and George Bouza.

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The World Bank
1818, H St., NW,
Washington, DC 20433
USA
# Energy and Development Report 1999

## Energy After the Financial Crises

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The purpose of the energy sector is to contribute to development by providing energy services to as many people as possible, as cleanly as possible, and as cheaply as possible. Fulfilling this purpose represents a formidable challenge — as much in developed countries as in developing ones. The Energy, Mining, and Telecommunications Department of the World Bank and the Energy Sector Management Assistance Program (ESMAP) are launching this new, annual Report as part of their joint effort to disseminate current thinking on how developing countries can best meet this challenge.

In the majority of developing country energy sectors, this challenge has essentially three interdependent parts: to expand access to modern energy, to mitigate the impact of energy use on the environment, and to make the supply of energy services more efficient. Chapter I contains two survey essays. The first of these takes stock of the progress and current issues in institutional reform — how best to organize and regulate the sector to meet these challenges. The second reviews the trends in the financing of developing country energy sectors and the changes in sector financial structure that have been brought about by institutional reform. These two discussions set the context for the twelve essays that make up Chapter II. These essays, contributed by leading thinkers on energy from inside and outside the World Bank Group, and from developing and developed countries, are the core of this Report: they represent a variety of views on the future of institutional and financial reform of developing country energy sectors, and reward critical reading. This year, the essays take as their theme the implications of the impact of the recent financial crises in East Asia, Russia, and Latin America for the future institutional and financial structure of the sector. The Report has no pretensions to be definitive on either of these fronts — but important lessons of experience are emerging on both.

It is natural to ask how this Report relates to the World Bank Group’s own involvement in energy. The principles which frame the Bank Group’s strategy in the energy sector are set out in three publications: The World Bank’s Role in the Electric Power Sector, Energy Efficiency and Conservation in the Developing World, and Rural Energy and Development: Improving Energy Supplies for Two Billion People. This year, we will publish another important strategy paper: Fuel for Thought: a New Environmental Strategy for the Energy Sector. Together, these papers outline how the Bank Group has re-oriented its energy sector assistance to its client countries in sympathy with their changing needs. A greater emphasis is now laid on promoting institutional reforms which help to develop energy markets that expand access to modern energy for the poor and reflect the environmental costs of energy use. Hand in hand with this re-orientation of goals, there has been a shift in the preferred instruments used, from direct financing, which has become less of a need in many countries due to the enormous expansion in private flows, to technical and policy assistance. This re-orientation has taken place in the context of the evolution of the Bank Group’s corporate strategy, which has increasingly reflected the fact that development is not simply an economic imperative, the challenge of which is technical. Today, the Bank Group’s comprehensive development framework targets structural, human, and physical needs; it emphasizes partnerships, synergistic aid programs, and increased local participation in programmatic decisions; and it lays stress on maximizing development impact rather than output. This broader strategy to promote sustainable development and to alleviate poverty is the guiding light of the Bank Group’s involvement in the energy sector.

If there is any one message that emerges from this inaugural Energy and Development Report, it is that despite encouraging trends in many developing country energy sectors, none of us — energy industry, financiers, NGOs, or policy-makers — have yet got the institutional and financial formula right. The crises exposed this fact starkly. I hope that this and subsequent issues of the Energy and Development Report will help us all in our common quest to provide cheap, clean energy to as many people as possible.
CHAPTER ONE

TAKEING STOCK OF PROGRESS:
THE ENERGY SECTOR IN DEVELOPING COUNTRIES

Energy sector reform has two main elements: the reshaping of sector policy, regulation, industrial organization, and market structure – institutional reform – and the restructuring of the way the sector is financed – financial reform. The essays in Chapter II, which form the core of the Report, treat a number of specific topics relating to energy sector reform in the light of the recent financial crises. The two survey essays in this chapter place these more detailed discussions in context, by outlining the progress to date and the current issues in institutional and financial reform respectively.
Institutional Reform

Yves Albouy*

Introduction

The goal of institutional reform of the energy sector in developing countries is to organize energy policy, legislation, regulatory framework, and market structure, in the way that best enables the energy sector to fulfill its role in development. Over the past two decades, there have been important changes in general development paradigms; and the perception of the energy sector's role in development has changed to reflect these. The principal changes in development paradigms have essentially involved an increasing acknowledgment of the importance in development of environmental and social considerations (Box 1). As a result, the importance for development of organizing the energy sector to minimize its impact on the environment is now widely understood. By contrast, awareness of the potential of energy sector reform to help alleviate poverty is still lagging. But promoting both environmental and social objectives are now acknowledged to be an important part of the energy sector's contribution to development, and the success or failure of energy sector institutions in doing this is central to any measure of the sector's overall performance.

This chapter arranges a review of the progress to date in the institutional reform of the energy sector around the three functions which are the sector's critical contributions to development:

- improvement of operational efficiency, including the elimination of wasteful and poorly targeted subsidies
- expansion of access to modern energy for the poor
- mitigation of the impact of energy use on the environment

For each of these functions, there is an assessment of progress to date; an analysis of the factors which have driven or constrained this progress; a review of emerging lessons; and a discussion of the impact of the recent financial crises. Where relevant, the reader is referred to specific essays in Chapter II: this chapter gives the context of current issues in institutional reform against which those essays can be read.

Box 1

The energy sector's mandate under the new development paradigms

Poverty alleviation. Growth is central to poverty alleviation, but the 1990 World Development Report, Poverty, stressed that a rapid and sustainable poverty reduction strategy has two equally important elements: job creation – promoting the productive use of labor – and safety nets – providing basic social services in health, nutrition, and education. In addition, certain "merit goods" – such as rural roads, urban public transport, and sewerage – deserve to be subsidized, because their public benefits are large but private willingness to pay for them is insufficient.

Access to modern energy can dramatically increase the productivity of labor, therefore giving energy a prominent role in job creation. Energy also plays a vital role in meeting basic needs, but the private benefits of energy use are usually high, and hence the need for subsidies is limited. Yet energy price subsidies are still common in many developing countries, despite the fact that they have been proved again and again to benefit the well off more than the poor, and to impose a cost on the economy which in many countries exceeds the total flow of aid, or the education and health budgets.

Environmental management. Maintaining the local and global environment is a vital part of development. The 1992 World Development Report, Development and the Environment, highlighted the difference between "tradeoff" situations – where economic growth comes at the expense of the environment – and "win-win" ones – where efficient growth and environmental benefits go hand in hand. "Win-win" opportunities are numerous in infrastructure services, but they require sweeping institutional changes, starting with the careful targeting of energy price subsidies.

Private participation and reform. In 1993, the World Bank approved policies that stress the need for sound commercial practices, independent regulation, and extensive private sector participation in the energy sector. These policies extended to the power sector a process that had first begun with the oil and gas sector in 1983, when network-based services still relied heavily on public sector provision to pursue economies of scale through integrated systems and large investment projects. The orientation towards introducing competition and the private sector was extended to all infrastructure sectors after the 1994 World Development Report, Infrastructure for Development, and the 1995 publication, Bureaucrats in Business.

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Improving the efficiency of the energy sector

Important advances in the technologies of energy production and supply over the past two decades have opened up the possibility of much improved operational efficiency in the energy sector. In the majority of developing countries, the development of an institutional framework to take advantage of this possibility has lagged, making the sector a frequent source of economic waste, and in many cases a fiscal burden as well. There are a number of typical sector ailments and commonly prescribed remedies summarized in Box 2, and a simple but useful institutional reform agenda, which applies to the power, oil and gas, and heat raising sectors, is often invoked:

- Commercialization of management and enhanced cost recovery.
- Passing legislation to enable restructuring and privatization.
- Establishing independent regulation of the sector.
- Unbundling production, transport, and retail supply.
- Introducing private ownership into the sector through new projects.
- Privatizing existing publicly-owned enterprises.

Box 2

Energy sector inefficiencies and remedies

As in other infrastructure sectors, the sources of economic waste and fiscal burdens in the energy sector can usually be traced to distorted pricing regimes, low quality of service, high technical and non-technical losses, low availability and efficiency of equipment, inefficient system operations, the lack of commercial management skills, and sub-optimal fuel and investment choices. The root causes of all these shortcomings are institutional: they are due in the end to inappropriate sector policy and structure, government interference, poor incentives systems and, in some cases, corruption.

Many of the prescriptions for these problems apply broadly to all infrastructure sectors: for example, regulatory reform and private participation (both through management, leasing, and concessions contracts, and through the ownership of new or divested assets). Difficult issues in implementing these prescriptions, such as transitional labor arrangements and the degree of discretion and independence afforded to regulators, are also common to all infrastructure sectors.

A number of restructuring options are specific to the energy sector:

- **Introducing competition is a priority.** The most vital innovation is making markets accessible to new entrants. After this, competition for a share of the market (e.g. bidding for concessions) is one option; genuine competition in the market (e.g. merchant plants in a competitive power pool) is even better, where it is possible.

- **Regulation** is particularly complex for power, because costs are highly sensitive to the volatile supply and demand balance: sophisticated regulation is required to ensure the benefits of competition are reaped.

- **Inter-regional energy trade** is often possible, and can enhance risk management and reduce costs and cost volatility, but requires co-operation in more than technical matters.

Progress to date

Progress on the basic reform agenda described above has been limited: out of 115 developing countries, only 12 have taken all six steps, and 42 have taken none at all.

- Latin America is the region most advanced in institutional reform, and the upstream oil and gas sectors are generally more liberalized than the power or downstream sectors.
- But on average, and across all sub-sectors, fewer than half of the steps have been taken. Fewer than half of all developing countries have allowed private sector involvement in new investments and only a quarter have even begun to privatize existing assets.
- Independent Power Projects (IPPs), by contrast, have become widely accepted, especially in East and South Asia. This opening to IPPs has encouraged some institutional reform; it has broken monopolies, spurred the modernization of financing instruments, contracts, and insurance legislation; transferred clean and efficient technologies; and helped reduced capital subsidies. But its successes sometimes obscured the pressing need to continue with further reform.
- In Central and Eastern Europe, many institutions for regional energy trade are disappearing. They are slowly being replaced by others, but barter payment for energy is still widespread and hampers progress. Heat raising and distribution utilities have become less dependent on municipalities and a few have been privatized2.

Catalysts and constraints

Increasing operational efficiency is attractive to all parties, but its welfare consequences are more complicated.

- **Investor interest in the energy sector has grown significantly, and the use of limited recourse project finance has broadened opportunities for Build, Operate, and Own (BOO) projects. The globalization of investors’ interests and asset management strategies, long a reality in the oil and gas sectors, is now happening also in the power industry.**
- **The prospect of energy shortages has spurred institutional reform in countries that are growing fast and need an efficient and reliable supply of energy.**
- **Political opposition is a major issue in the introduction of independent regulation, the enforcement of cost-reflective pricing, and the unbundling and divestiture of publicly-owned assets.** Workers are laid off, gains are unevenly distributed, and resources commonly considered to be the national patrimony ceded to private, and often foreign, owners. Though often underrated by politicians, these difficulties are usually underrated by their technical advisers3.

Emerging lessons

- **Allowing the regulator a lot of discretion has not worked in countries where corruption is common and judicial governance is dysfunctional. In these circumstances, it is better to set out precise tariff-setting rules both in legislation and in contracts with individual service providers. First in Chile and later in...**

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1See Robert Bacon, A Scorecard for Energy Sector Reform in Developing Countries, Ch. II.
2See John Besant-Jones, The Impact of the Financial Crisis on the Power Sector of Transition Countries, Ch. II.
3See Stephen Karekezi, A View from Africa, Ch. II.
4See Alfonso Cristobal Revollo, Reflections on the Politics of Reform, Ch. II.
Bolivia, a law which was precise on cost-recovery and energy access by the poor was the cornerstone of reform.

Private ownership makes a difference. Unlike publicly-owned companies, private shareholders are in a strong position to help the regulator counterbalance political pressures to devise from sound commercial discipline, particularly at the level of retail sales. Privatization helped buttress cost recovery and competition in Colombia, and even in the UK, where the publicly-owned utilities had a commercial orientation, privatization hardened budget constraints, eliminated the government asset owner’s interests in keeping prices high, and allowed the capital markets to allocate resources more efficiently.

• Competitive bidding for BOO or BOT projects for energy production has often failed to result in an optimal allocation of risks between the private and the public sector, and has not reduced prices as much as competition in the market would have done.

• In the power sector, conflicts of interest and issues of market dominance arise when former public monopolies are both competitors in the pool and owners of the transmission grid. Independent System Operators (ISOs) and the right market rules can help, but improving market structure is the best option.

• Liberalizing the markets for primary fuels – coal, gas, and fuel oil – has proved essential to the allowing new entrants to challenge incumbents in the UK and in South America.

• IPPs, where they constitute a significant share of total capacity, have the potential to hamper the efficiency in system operations by requiring contractual arrangements which limit the scope for introducing competition further along in the reform process.

• Evidence from the leading reformers suggests that extending competition to retail supply is worth the cost. It reduces the market power of distributors allied with generators and allows choice and voice on the demand side.

**Impact of the crises**

The financial crises have highlighted many of the lessons outlined above particularly through their differential impact in the markets for oil and gas and power.

• In the markets for oil and gas, US dollar prices have fallen in line with demand: production costs have become price-drivers again and high-cost producers have suffered. Incentives to restrict production have evaporated, and there is increased pressure from domestic lobbies to normalize tax regimes.

• In the electricity markets of Asia, on the other hand, demand fell, but IPP contracts kept bulk prices high as the currency devaluations left retail tariffs well below these levels in US dollar terms. Many contracts are in limbo in spite of their security payments. Privatization helped buttress cost recovery and competitiveness in electricity markets.

The political prospects for institutional reform improved following earlier crises in Latin America, and may do so for similar reasons in Asia. In Eastern Europe and the FSU these opportunities will either be multiplied by existing incentives to meet the EU Directive for power market deregulation, or diminished by permissive monetary and fiscal policies and the prevalence of barter trade.

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5 See Manuel Dussan, *Commentary - The British Reform Experience: Commentary: a Developing Country Perspective*, Ch. II.
6 See Stephen Littlechild, *Privatization and Competition in the British Electricity Industry, with Implications for Developing Countries*, Ch. II.
7 See Jean-Marie Bourdaire, *Empowering the End User: Market Reform Lessons from the IEA Countries*, Ch. II.
8 See Shane Streefker, *Oil Prices: Recent Trends and Forecasts*, Ch. II.
9 See Michael Klein, *The Asian Crises and Structural Change in Energy Markets*, Ch. II.
10 See Piyasvasti Amranand, *A View from East Asia*, Ch. II.
11 See Mark Tomlinson, *Access to Energy Services: a Brighter Future?*, Ch. II.

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**Expanding access to modern energy for the poor**

Expanding access is much more than rural electrification. For one thing, a vast and increasing number of the world’s poor live in urban or peri-urban areas. For another, the challenge is to expand access not just to electricity, but to whatever forms of modern energy are needed. Access to energy which will facilitate productive end-uses will be a natural corollary of improving the commercial orientation and economic efficiency of the sector described above – given appropriate credit arrangements. However, certain energy services also contribute to basic nutritional, health, and environmental needs, and there is a case for subsidizing access to these kinds of energy services where it is not feasible to recover costs completely.

The challenge of expanding access deserves better than the well-meaning but misguided romanticism of past policies based on the notion that electricity service is a right which does not need economic justification. The poverty of performance in terms of service coverage is sobering (Box 3, and has been shown again and again to be due to institutional failures rather than shortages of funds or technical skills. Finance can be raised through policy reform, and as the evaluation of numerous rural development programs has shown, even well-funded projects founder and technical skills dissipate without an appropriate institutional framework to support them.

**Box 3**

**Electricity so prized and yet so scarce!**

There are still 2 billion people without electricity: under a business-as-usual scenario this number will increase to over 3 billion by 2010. In South East Asia and Africa, more people are born each year than currently have access to electricity. Yet the cost of supplying electricity is almost always less than that of supplying kerosene (though subsidies disguise this fact). In terms of cost, the main barrier to access is the up-front cost of connection to the grid: but this is a corollary of the delivery mechanism – grid extension by the utility – which could be solved if other mechanisms are encouraged.

**Progress to date**

Clarifying the type of energy access which contributes to basic needs would provide a basis on which to reform sector institutions and to revamp subsidy policy. Current subsidy policies too often fail to target basic needs, subsidize volume of consumption over access, and are overly generous for “luxury” end-uses.

• Almost everywhere, the utility model is still the principal instrument for expanding access to electricity. For peri-urban areas, where medium voltage networks are used, it is seen as adequate. But for rural electrification, the assessment is mixed.

• Co-operatives have been tried with success in Bangladesh, Costa Rica, and Bolivia, but the formula is still elusive, as shown by the demise of many such schemes in the Philippines. The scope for cost reduction (25-50%) is much higher than is
usually assumed, and there is often little need for uniform standards of reliability and safety in the low voltage network; but prevailing rules and habits often inhibit technical and managerial innovation.

- Chile and Argentina introduced competitive bidding for rural electrification amongst established utilities and new entrants as a way to reduce its cost.
- In off-grid situations, the small dealer model has achieved some success in Kenya and Zimbabwe (by direct sale) and the Dominican Republic (by leasing).

**Catalysts and constraints**

Policy-makers and regulators are the key players in the promotion of access. Without deliberate incentives, private developers pay little attention to access, since urban markets tend to remain more attractive to investors than rural ones. Requiring private power utilities to facilitate access and consumption through cross-subsidization in their market area is a first step, but this approach has limitations. Privatization of retail supply is the simplest solution for two reasons: first, it creates pressure to reform both policy and regulation to attract private investment; and second, the lease or sale of assets can generate funds which can be used for social purposes.

**Emerging lessons**

- Subsidies that are not targeted accurately are wasteful and counter-productive: kerosene subsidies have frequently been hijacked by wealthy transport entrepreneurs; subsidized block tariffs for electricity benefit the well off more than the poor in almost every case.
- Macroeconomic reform provides makes targeting subsidies both more necessary and more possible. In many countries in transition, the demographics of poverty have shifted significantly over the past decade, but subsidies schemes have seldom been re-designed in response. The few countries which have successfully retargeted subsidies (e.g. Chile, Argentina, Bolivia) generally did so when privatizing retail supply.
- Financing of subsidies is still too often based on cross-subsidization, which in many circumstances have a very negative impact in a number of ways. In many countries, overcharged electricity users in the industrial and commercial sectors increasingly evade payment and bypass grid service, thus shrinking the revenue base and increasing the use of uneconomical diesel sets.
- Subsidizing access alone is often simply a matter of financial intermediation. Scheduled payments (Bolivia) or micro-credit schemes (Sri Lanka) for connection to the grid, and matching grants for private developers, have proved to increase the rate of access dramatically.
- Taxing fuels for the well off indirectly raises the prices set by the market for the cheaper substitutes used by the poor.
- Technology can help: power demand limiters can avoid abrupt disconnections in case of payment arrears whilst insuring against abusive consumption; prepayment meters avoid arrears and target specific beneficiaries by giving them personalized prepayment cards.

**Impact of the crises**

The impact of the financial crisis on access could be severe in Russia and East Asia – particularly in Indonesia – if broad subsidies are not redesigned to target them towards the provision of basic needs to the poor. Some adjustment in the quality of service (for example, a reduction in reliability when the supply cost is highest) may be needed. Rural electrification strategies may be stalled – though this is hardly a problem exclusive to countries impacted by the crises.

**Energy and the environment**

Energy production and consumption have a significant impact on the environment. Fortunately, the energy crises of the 1970s raised the world’s awareness of the need for energy efficiency, and the challenge of mitigating local and regional pollution have become of increasing concern to many countries. Addressing global pollution issues, in contrast, and in particular mechanisms to limit Greenhouse Gas (GHG) emissions, remains a relatively recent and less widely supported effort. But the fundamental challenge in addressing all both local and global pollution concerns will be met by adapting sector policies and institutions.

**Progress to date**

Energy conservation is particularly sensitive to the institutional environment (Box 4), and mixed progress in devising effective regulation explains why conservation has moved slowly, especially with end-users. In many countries, opportunities have been missed even in areas with high energy costs, because suppliers have not had adequate incentives for lack of market reforms.

- The few transition economies which have raised energy prices substantially, improved environmental legislation, and restructured their industry have shown that demand side management (DSM) can work.
- A few countries have started experimenting with Energy Service Companies (ESCOs), which are contracted to reduce a client’s energy needs, and with utility-driven DSM.
- On the supply side, privatization and market reforms have brought about important reductions in technical losses, and have replaced old and inefficient infrastructure.
- Wind and solar power has attracted attention for the supply of isolated areas but the policy is generally still one of pilot testing.
- An increasing number of countries have put in place environmental authorities, standards, and procedures. Standards are often comprehensive and state-of-the-art, covering gaseous, liquid and solid waste; the procedures are usually applied broadly across the energy sector. These reforms have stimulated innovation – for example, in the utilization of sugar bagasse for electricity generation. But in general, organizations are relatively weak at enforcing standards and action plans.
- New international institutions like the Global Environmental Facility (GEF) have prepared the ground for worldwide action through their pilot and second phase projects. In December, 1997, the Kyoto agreement on the need to curb GHG emissions, as well as a few initiatives by the private sector, confirmed that the movement started in Rio de Janeiro in 1992 is gaining momentum, but also that huge roadblocks remain.
Box 4
Markets for energy efficiency

Energy efficiency (EE) represents the most powerful "win-win" strategy to reconcile environmental quality with economic performance. Many developing countries are in dire need of EE: energy intensities are high in formerly planned economies and cold climates; energy costs are high in landlocked and poorly endowed countries; local and global pollution is serious in highly urbanized and fast-growing areas. EE interventions are varied in scope, including both retrofits and new projects, and incorporating supply side measures (oil refining, heat and power production and distribution) as well as demand side ones (industrial processes, transport, buildings, public lighting, and home appliances). Demand side interventions have the best potential since they impact the entire supply chain.

Progress has been hampered by a number of issues, many of them institutional:

**Low energy prices.** Subsidized tariffs or failure to meter or collect payment kills users’ interest.

**Fear of the unknown.** Hardware may be cheap but hard to procure; opportunities and options for EE may be unfamiliar; its impact may not register; making it right takes time and money.

**Asset valuations.** EE improvements are not reflected in the resale value of buildings and plants.

**Financing.** EE lacks access to lending, particularly for households and small enterprises.

**Cost of customization and access.** For retrofits, plant data is incomplete, standard solutions not readily applicable, and extra costs incurred for decommissioning, demolition and reconstruction.

**Catalysts and constraints**

Civil society has forced energy conservation and the environment to center stage, and donors and governments are increasingly responsive. Technical progress and open trade in new technologies have also contributed significantly: the cost of environmental mitigation generally does not exceed 5% of supply costs.

Pricing reform and privatization can help the enforcement of standards: governments have often obtained cleaner infrastructure from private investors than they have from the public sector. Equipment vendors show increasing interest in developing and transition countries but in most countries, energy prices, which are pegged to oil prices, have been too low to boost interest in demand-side efficiency.

**Emerging lessons**

- Responsible governmental organizations are often very short of financial and human resources, and lack a clear mandate backed by law.
- Standards need not be unnecessarily complex and customized; environmental assessments should not be co-ordinated by the same officials who approve investment projects, or emasculated by inadequate action plans and one-size-fits-all procedures.
- Off-the-shelf regulation and the preparation of sector-wide assessments to improve the cost-effectiveness of project-specific ones are economical where resources are scarce; approval procedures can be relaxed for small projects with little potential impact.
- Countries that have already developed their standards and organizations for upstream work do well to re-deploy their attention and resources towards enforcement and monitoring activities. Action tends to be the casualty of inadequate budgets and institutions more than analysis.
- Participatory methods have a prominent place: giving a voice to local communities most likely affected by pollution gives an effective mandate to monitoring and enforcement.
- The stalemate on global environmental issues is serious: some OECD countries like the US will not countenance binding emissions reduction targets until major developing country emitters do the same; but developing countries see GHG reduction as a brake on development which could be mitigated only by a massive transfer of technologies and by the trading of emissions rights – a prerequisite of which is an agreement on targets.
- Reformers must ensure that environmental management, long the exclusive province of government in areas such as hydropower development, does not fall between the cracks when the process of energy sector reform redistributes the responsibilities of the public and private sectors.

**Impact of the crises**

Energy conservation and pollution mitigation are essentially long term investments, and as such remain sound despite their increased cost and the scarcity of foreign exchange due to the financial crises.

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1 See Thomas Johansson and Susan McDade, *Global Warming Post-Kyoto: Continuing Impasse or Prospects for Progress?, Ch II.*

2 See Dennis Anderson, *Addressing Pollution Problems in Developing Regions: an Update on Options, Ch II.*
Financial Reform

Felix Martin*

Introduction

The recent wave of institutional reform analyzed in the previous survey essay has brought far-reaching changes to the financial structure of many developing country energy sectors in terms of the sources of financing, the planning of investments, and the creditworthiness of the sector. In fact, this reform of sector financial structure has typically been one of the major objectives of the overall energy sector reform program. The benefits it has to offer in theory are distinct from the improvements in sector performance that come from institutional reform. Based on recent experience, reforming the energy sector's financial structure and increasing the share of private capital can bring the following basic benefits (Box 1):

- more efficient mobilization of financial resources
- easing of fiscal constraints imposed by the sector
- enhancement of sector creditworthiness

This essay reviews the recent trends in developing country energy sector financing and the impact that the financial crises of 1997-99 have had on them. The analysis concentrates on the changes in cross-border private flows to the sector, since in the majority of developing countries the trend towards increasing private finance has depended on the international capital markets: domestic capital markets are generally underdeveloped, and local investment capital in any case relatively scarce. There are three sections:

- Recent trends in private financial flows to developing countries.
  This section reviews the trends in total financial flows to developing countries over the last few years – and briefly summarizes what impact the financial crises have had on these aggregate flows.
- Recent trends in private financial flows to the energy sector in developing countries.
  Worldwide, the trend towards increased private finance for the energy sector has been driven above all by flows to the power sector. This section analyzes the trends in private flows to developing country power sectors, and the different patterns that have emerged in the share of these flows that have gone to finance divested public assets or new investment.
- The future of energy finance in developing countries.
  A final section briefly extrapolates the implications of the first two sections for the future of energy sector financing in developing countries. The essays in Chapter 11 present more detailed views on the future of energy financing: this section draws out the most general and important lessons.

Box 1

Why reform energy sector financing?

More efficient mobilization of financial resources
The experience of the leading reformers – especially the UK and Argentina – has shown that private ownership and the discipline exerted by the capital markets have resulted in a more efficient mobilization of financial resources in the sector. Investment planning has been subjected to more rigorous scrutiny, capital structure has been optimized to give the best return on assets, and the apportioning and mitigation of risks has become much more efficient.

Alleviation of fiscal constraints
In many developing countries, there have also been important fiscal motives to change the financial structure of both the power and the oil and gas sector:
Power: Cost-recovery in publicly-owned power utilities has often been so poor, due to large technical and non-technical losses and poor financial management, that heavy public subsidization has been required, and system expansion has had to be financed publicly, at the expense of expenditure on other sectors. Private greenfield investment alleviates the claims on scarce public and multilateral funds for system expansion, and privatization of existing assets reduces the need for subsidies.
Oil and Gas: In most hydrocarbons-rich developing countries, the publicly-owned oil or gas company is a substantial net contributor to the budget. The precipitous decline in the price of oil over the past year and a half has undermined public spending programs, and made it desirable to step up production in order to maximize revenue. However, the costs involved in new exploration and production are generally beyond the capacity of most of these publicly-owned companies, and a new financing structure has had to be devised for the sector, typically involving recourse to private investment.

Enhanced creditworthiness
The most fundamental change in the financial structure of the reforming energy sectors has been better recovery of costs from the end-user. Without pricing energy services to reflect the cost of provision – tariff reform – and without the elimination of non-payment on a large scale, no schedule of investments either to maintain or to expand the energy sector can ultimately be sustainable, whether financed privately or publicly. The institutional reforms which have permitted tariff reform and independently regulated private participation in the retail supply of energy have been responsible not only for an increase in the level of private capital flows to the sector, but for an increase in the sector's creditworthiness – and hence its attractiveness to any capital, public or private.

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The background: Financial flows to developing countries – past trends and future prospects

Private financial flows to developing countries, which had sustained a steady acceleration for over a decade when the crises first struck in 1997, fell back last year to the level they had reached in 1994, and are forecast to suffer a further decline this year (Figure 1).

**Figure 1**
Total net capital flows to developing countries, 1995-99(f)

![Graph showing total net capital flows to developing countries, 1995-99(f)](image)

The boom in private financial flows to developing countries had included all types of finance. Foreign direct investment ballooned from US$ 20 billion in 1990 to over US$ 120 billion in 1997. Private portfolio equity grew from an esoteric source of finance comprising only 3% of all cross-border flows, to a major instrument in some markets, accounting for 11% of the total in 1997. Most importantly for the infrastructure sectors, debt financing using international creditors became a more and more realistic option in developing countries, as private money fled the low returns in the established markets in order to seek out higher yields in developing countries, and foreign banks became more and more amenable to making loans of relatively long tenors, and at relatively low rates of interest. As a result, the proportion of debt financing in internationally-financed infrastructure investments in developing countries grew from around 60% over the period 1990-93, to around 80% in the period 1994-96, and continued to rise up to the crises.

Since late 1997, a series of severe regional economic crises have struck many developing countries. A large number of factors contributed to these crises: they have been investigated in depth elsewhere (see, for example, the World Bank’s *Global Development Finance* 1998). But in terms of international private capital flows, what we have witnessed over the past year and a half has been a massive reassessment of the riskiness of investing in developing countries. Put bluntly, the international financial markets have rediscovered emerging market risk. This has imposed severe limits on investment plans in those developing countries which were able to attract cross-border private finance prior to the crises, and cut off hope for those which were not. Debt financing, which is the staple of infrastructure project finance, has been worst hit. Despite encouraging signs for some East Asian countries, it is unlikely that flows will recover to pre-crisis levels for some years.

The distribution of cross-border private capital flows to developing countries before the crises was not even, of course. As a result, the impact of the financial crises has also been unevenly spread. Latin America, which had been the most pronounced beneficiary of the markets’ extensive reconciliation with the idea of lending to emerging markets, saw the spread on Brady bonds fall almost 1,200 basis points in between the beginning of 1995 and the end of 1997, by which time the markets deemed some Latin American countries little more risky for investment than the higher risk OECD countries. Following the crises in East Asia, however, there was an immediate rise in the secondary market spreads on all emerging market bonds, and by the end of last year, when financial crisis erupted in Latin America itself, the spread on Brady bonds was back to its 1995 level. The drying-up of international financial flows that these spreads reflect threaten to reduce private cross-border financial flows to Latin America to around US$ 55 billion in 1999 – barely half of what they were in 1997.

The region worst affected by the financial crises has been the one where they began. East Asia – and in particular Indonesia, Malaysia, South Korea, Thailand, and the Philippines – which had enjoyed a decade of liberal private financing from abroad, suffered a dramatic turnaround: the value of their stock markets collapsed by an average of 44% over 1997. Bond spreads surged by hundreds of basis points, and massive capital flight has led to a virtual elimination of net private capital flows to these countries. Worst hit were the debt markets: private creditors to these five countries, who had provided over US$ 104 billion of capital outflows in 1998, and will in all likelihood be net capital importers from these economies in 1999 as well (Figure 2).

**Figure 2**
Total net capital flows to Indonesia, Malaysia, South Korea, Thailand, and the Philippines, 1995-99(f)

![Graph showing total net capital flows to Indonesia, Malaysia, South Korea, Thailand, and the Philippines, 1995-99(f)](image)

Source: Institute of International Finance, Inc.
The global shakeout:
The financial crises and private investment in the power sector

The power sector was a leading beneficiary of the boom in private financial flows to developing countries up until 1997 (Figure 3 and Table 2). Power sector investments absorbed an average of 16% of all private flows to developing countries in the latter years of the period — and nearer 20% in the cases of the two biggest recipients of private flows, East Asia and Latin America. Reflecting the typical greenfield project financing structure of 76% debt to 24% equity, the majority of the private flows to finance incremental investment took the form of debt — the markets for which have borne the brunt of the financial contraction.

Figure 3
Private finance for investments in developing country power sectors, 1994-98

1998 - US $ billions

Distribution by region

The similarity of trends between private flows to the power sector and total private flows extends to their regional distribution, with one significant difference in the case of South Asia. Latin America and East Asia, the largest beneficiaries of total private flows, have also dominated private flows to finance power sector investments, garnering 85% of the total between 1994 and 1998. South Asia’s share of total cross-border private flows has been relatively small; but the region has attracted 15% of all private finance for greenfield power sector investment. The amount of power sector investments in Africa and the Middle East financed privately over between 1994 and 1998 has been very small. The whole of Sub-Saharan Africa attracted only US$ 2.3 billion in private capital for power sector investments: the Middle East and North Africa did not fare much better — attracting just over US$ 3 billion. Eastern Europe and Central Asia, has had US$ 5.5 billion in total private investment.

Distribution by type of investment

In the four regions where private flows to the power sector have been significant, two distinct patterns have emerged. On the one hand, the rapidly growing economies of East and South Asia have seen an overwhelming predominance of greenfield investments in their expanding portfolio of privately-owned power sector assets. On the other hand, Latin America and the Eastern European and Central Asian region saw the majority of private flows to their power sectors go to finance the purchase of divested assets.
East and South Asia: the greenfield revolution

In East and South Asia, the predominant factor of change in power sector financial structure has been the increasing share of total incremental power sector investment financed privately.

Figure 5 shows the distribution of private flows to the power sector in East Asia between different types of investment over the period 1994-98. GDP growth in East Asia averaged 9.9% per year between 1991 and 1997, requiring a heavy schedule of capacity additions to meet the ballooning demand for electricity. This phenomenal macroeconomic growth explains the distinct bias of the large amount of private capital which has poured into the power: only one quarter of all private flows to the power sector between 1994 and 1998 financed the purchase of divested assets – the remaining three quarters financed investments in greenfield projects, the great majority of them in new generating plant.

**Figure 5**
Private finance for investments in the power sector in East Asia, 1994-98

Growth rates in South Asia have also been buoyant over the last decade, averaging 5.7% per year between 1991 and 1997, and a similar distribution of private flows to the power sector (though a distribution of very much smaller flows) has emerged (Figure 6). Nearly 95% of all private investment in South Asian power sectors has been in greenfield generation plant.

Latin America, Eastern Europe, and Central Asia: privatization dominant

In Latin America and the Caribbean, and in Eastern Europe and Central Asia, the primary factor of change in power sector financial structure has been the divestiture of publicly-owned assets.

Figure 7 shows the distribution of private flows to the power sector in Latin America and between 1994 and 1998. Nearly half of all flows have gone to finance the purchase of divested distribution companies, and another 23% has financed the privatization of generating plants.
of generating plant; only the remaining third has financed the construction of greenfield capacity. Latin American GDP growth has been more modest than that of the Asian regions over the past decade — averaging 3.4% per year — and macroeconomic reforms are much more advanced; but the different pattern of private participation in the power sector also reflects much stronger progress in the institutional reform of the energy sector.

Eastern Europe and Central Asia experienced a substantial macroeconomic contraction throughout the 1990s. There has been, as a consequence, no increase in electricity demand, and little need for incremental investment in generation: in most countries in the region, demand has in fact fallen so rapidly over the last decade that there has not even been a need for investment to replace retired capacity. There have been concerted efforts at institutional reform in a number of Eastern European countries and in Kazakhstan, which have resulted in a number of generation and distribution privatizations (Figure 8). A regional assessment across the whole Eastern Europe and Central Asia is of somewhat limited value, since the differences between the leading reformers and the laggards is particularly wide: but overall, the level of private investment in the power sector in the region remains low, and the sector’s financial structure remains substantially unaltered.

The impact of the financial crises

The financial crises have affected power sector financing both by triggering massive macroeconomic downturns which have resulted in a stagnation or decline in electricity demand, and by drastically downgrading the risk profile of investments. These consequences have had a negative impact both on private investment in divested assets and on private incremental investment.

Divestiture
Private investment in divested assets continued on an upward trend in 1997 in East Asia, Latin America, and Eastern Europe and Central Asia. In 1998, however, the level of divestitures dropped significantly in all three regions: by 95% in East Asia; by 70% in Eastern Europe and Central Asia; and by 50% in Latin America.

Incremental investment
Table 1 shows that in East Asia, South Asia, and Latin America, the three regions which captured 98% of all private greenfield investment, the share of private capital in total incremental power sector investment has fallen sharply following the crises.

<table>
<thead>
<tr>
<th>Table 1</th>
<th>Share of private capital in total incremental power sector investment, 1996-98</th>
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<tr>
<td>East Asia</td>
<td>68%</td>
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<td>South Asia</td>
<td>38%</td>
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<tr>
<td>Latin America and the Caribbean</td>
<td>86%</td>
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<tr>
<td>All developing countries</td>
<td>40%</td>
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</table>

These steep declines in the proportion of total incremental investment in the power sector financed privately — by over half in the case of Latin America, and by over three quarters in the case of East and South Asia — show the negative impact of the reassessment of country, currency, and sector-specific risks on the willingness of the private sector to finance incremental developing country power sector investment.

Thus the financial crises have stalled the reform of power sector financing structure both in those regions where divestiture has been the driver — Latin America, and Eastern Europe and Central Asia — and in those regions where incremental investment has been the instrument of change — East and South Asia. They have also highlighted an important difference between the two patterns, since the two negative consequences of the crises — the collapse in demand and the downgrading of the risk profile of investments — will both restrict private incremental investment more than private investment in divested assets.

Collapse in demand
The macroeconomic downturns in the countries hit by the financial crises have lessened the attractiveness of investment in both divested and greenfield assets. More fundamentally, they have eliminated the need for incremental investment in affected countries, and with it the pattern of restructuring sector finances more or less exclusively through increased private greenfield investment.

Downgrading of risk profiles
As noted earlier, the financial crises constituted a major reassessment of emerging market country risk: they have also precipitated a far-reaching re-evaluation of many sector-specific commercial and regulatory risks. In the case of divestiture, there will be a natural antidote to the market’s new caution in the form of a corresponding reduction in asset prices which may re-animate the market’s appetite. By contrast, the increased cost of financing for greenfield investment will only be mitigated by extensive reforms to renew confidence in the macroeconomic and sectoral environment.

The evidence suggests that in Latin America and Eastern Europe and Central Asia, where divestiture was already the dominant driver, reform of the power sector’s financial structure is continuing, albeit more slowly. In East and South Asia, however, soaring system reserve margins and prohibitive risk premiums have put a complete stop to system expansion, and hence to the sector’s financial restructuring. If the reform of the sector’s financial structure is to continue over the next few years, convincing institutional reforms will have to be implemented to allow a rapid shift to privatization as its main driver.
The future of energy finance in developing countries:
Institutional reform for sector creditworthiness

The evidence from those countries such as the UK, Argentina, and Chile, that have extensively reformed the financial structure of their energy sector, strongly suggests that the essential institutional innovation of the independently regulated and competitive supply of energy services can deliver the three financial benefits described in the introduction – improved financial efficiency; the easing of fiscal constraints imposed by the sector where they exist; and the enhancement of sector creditworthiness. Appropriately reformed sector institutions are proving much better at delivering these benefits than the publicly-owned monopoly utility.

The practical challenge in most developing countries is how to manage the transition from the monopoly utility and public ownership, to the competitive supply of energy services and private finance. In the case of the power sector, two distinct transition patterns emerged in East and South Asia, on the one hand, and Latin America and Eastern Europe and Central Asia, on the other; and the latter pattern – of adapting sector financial structure mostly through the divestiture of publicly-owned assets – is by necessity more resilient to the impact of macroeconomic crises. But institutional and financial reform strategy must be tailored to the particular conditions in a given country, and a particular sector. The essays in Chapter II explore in greater detail how a number of different models of institutional and financial reform have weathered the crises, and to what extent they can serve as guidelines for the improvement of sector performance through institutional reform, and the successful attraction of private capital.

Nevertheless, for the long-term financial structure of the energy sector, two general messages emerge as applicable across all regions, and all sectors:

**Sector creditworthiness** must be the guiding objective of all reforms of sector financial structure. A healthy cash flow from end-user to distributor to generator, refiner, or extractor, represents a viable proposition to any investor, public or private, under any demand conditions. The best way to improve fundamental sector creditworthiness is through the deregulation of pricing, and the privatization of retail supply, which will facilitate cost-recovery and the internal generation of investment capital. The essays by Stephen Littlechild, Manuel Dussan, Jean-Marie Bourdaire, and John Besant-Jones, explore this point in detail.

The availability of private capital for investments will depend both on the degree to which countries install market fundamentals in the broader economy – a sound legal framework, good governance, and the development of local capital markets and an efficient banking sector – and on the degree to which they meet the basic criteria for well-functioning markets in the energy sector – sector creditworthiness, independent regulation, and competition. Reforming the institutional structure of the energy sector to ensure these market fundamentals is the surest way of mitigating the risks that will otherwise keep private capital out. The essays in Chapter II by Michael Klein, Piyasvasti Amranand, and John Besant-Jones, discuss this point more thoroughly.
Table 2
Private investment in developing country power sectors, 1994-98

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<th>Region</th>
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<th>Capacity (GW)</th>
<th>US$ Billion</th>
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<td>15.4</td>
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<tr>
<td>Developed Regions (excluding US and Canada)</td>
<td>Total</td>
<td>9.8</td>
<td>18.5</td>
<td>9.3</td>
<td>24.4</td>
<td>18.7</td>
<td>28.4</td>
<td>18.1</td>
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<td>6.1</td>
<td>20.4</td>
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<td>6.6</td>
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<td>7.8</td>
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<td>0.6</td>
<td>2.7</td>
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<td>10.9</td>
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<tr>
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<td>12.2</td>
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<td>0.0</td>
<td>14.8</td>
<td>0.0</td>
<td>57.6</td>
</tr>
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</table>

NOTE: Based on a universe of 1,096 transactions (about four-fifths with actual transaction values, the balance being estimated with ratios statistically derived from the database).

Source: PHB Hagier Bailly Inc., March 10, 1999
CHAPTER TWO

ENERGY AFTER THE FINANCIAL CRISIS

This chapter contains twelve essays contributed by leading energy thinkers and practitioners from inside and outside the World Bank Group, and from developed and developing countries. The first four essays deal with the predicament of developing country energy sectors after the financial crises. The next four are concerned with the longer-term questions of energy sector reform, and the lessons that are emerging from the developed and developing countries that have already embarked on reform. A third section deals with the environmental impacts of energy use. The final two essays address the pressing question of how to expand access to modern energy for the poor, especially in Africa.
We learn about geology the morning after the earthquake
(Ralph Waldo Emerson)

The Asian financial crisis is likely to propel the world faster than expected towards:

• The introduction of genuine competition in power and gas markets.
• The breakdown of production restraint among low-cost oil producers.
• The emergence of a more seamless and competitive market for all forms of energy, stimulating innovation and a long-term decline in the real cost of energy.

This essay focuses on two of the key levers for change: stresses on private power projects in East Asia and on oil exporting economies. It explores the immediate impact of the crisis in these areas, and the deeper, structural faultlines that have been exposed as a result.

The immediate impact on the markets for oil, natural gas and power

The crisis, world oil markets, and major oil exporting nations

Oil prices have fallen by about 40 per cent between 1997 and early 1999, almost as much as in 1985/6, the biggest decline in history. Then, prices for Brent quality crude oil fell from about US$ 40/bbl (in money of 1998) to about US$ 20/bbl. This time around prices fell from a little under US$ 20/bbl down to around US$ 11/bbl.

The response of world oil markets to the crisis has differed from that of regulated electricity systems operating under long-term power purchase agreements. In the world markets for oil, lower demand leads to lower spot prices. Gas prices are declining in Europe and Asia, where gas contracts tend to be linked to oil prices. Elsewhere, cheaper oil is applying downward pressure on gas prices as dual-fired capacity in power and industry threatens to switch back to burning liquids. Lower prices cushion the economic slowdown as they help consumers cope better. In particular, the strong economic performance in Europe and the United States during 1998 has been buoyed by low oil prices, which may have added up to 0.4 points to world GDP growth.

Where bankruptcy systems function reasonably well losses are allocated first to shareholders and then to the providers of debt, and physical production tends to continue as long as operating costs do not continue to exceed price. High cost oil producers in Canada and the United States are fast reducing production as they face cashflow problems and bankruptcy. Investment budgets for exploration and production throughout the oil industry are being cut back. Investors in emerging new producing areas such as the Caspian are nervously re-assessing the profitability of projects.

The major unsustainable adjustment stresses are experienced by oil-dependent nations that have experienced a terms of trade shock paralleling the economic shock to the Asian crisis economies. Middle Eastern oil exporting countries have seen their

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purchasing power decline by almost 8 per cent. Elsewhere coun-
tries like Nigeria, Mexico, Russia and Venezuela were hard hit. Politically difficult and contentious fiscal adjustment is required here and may yet lead to political instability in some countries.

**Structural faultlines in traditional electricity and oil markets**

As well as creating serious and widespread hardship, the crises are revealing deep structural deficiencies in energy markets. If politicians are able to use the crisis to improve sector structure, then short-term adjustment will be smoother and long-term productivity growth higher.

**Faultlines in electricity markets**

Consider first the case of independent power projects operated under long-term power purchase agreements. Box 1 demonstrates how the crisis impact might have looked if, prior to the crisis, fully functioning competitive power markets had been introduced based on private ownership.

**Box 1**

**A competitive power market reacts to a macro crisis**

In a crisis, demand for power is reduced. If there is a competitive power market, where consumers pay the full price of electricity and a functioning bankruptcy regime backstops private debt workouts, the immediate consequence is that electricity spot prices fall. Fuel supply contracts to power generators, and long-term electricity supply contracts to consumers, both of which depend at least partly on electricity spot prices, lose value. Losses are allocated first to providers of equity, next to speculators who have taken on price risk under derivative contracts, and then to the providers of various classes of debt. Fortunately, the downward adjustment of prices automatically stimulates demand for electricity, minimizing the need for shutdown of production. Most importantly, taxpayers are not asked to foot the bill. Altogether, the adjustment tends to work more like it does in well-developed oil markets.

The reason adjustment does not work like this in electricity sys-
tems based on long-term power purchase agreements is due to two major structural flaws in such systems – the inadequacy of consumer prices and inefficient allocation of market risk.

**Adequacy of consumer prices**

Governments in many countries have turned to IPPs to reduce the need for public sector funding, while still creating new electricity capacity. Typically, governments have at the same time shielded away from raising electricity consumer prices to fully cost covering levels, including the cost of capital for private service providers. Precisely because of this unwillingness to raise consumer prices, the financial strength of many power purchase agreements is dependent on explicit or implicit government guarantees. This includes the typical case, in which the off-taker from an IPP is a state-owned utility. Regular default proceedings among private parties, which would lead to bankruptcy and takeover, are not usually permitted by the government: as a result, the government has to pay, either by assuming the debt of the utility, or by bailing out the banks that lose due to the utility’s failure to meet its obligations. Ultimately, taxpayers are asked to foot the bill. The amounts involved are often non-trivial. In the Philippines, the foreign debt of the National Power Corporation amounts to some 20 to 25 per cent of the national debt.

The fundamental reason for this problem, is that consumer prices do not cover the costs of providing electricity. If a government wants to reduce fiscal support for power sector investment it has to allow consumer prices to reach levels sufficient to pay for the service. Private investors can finance a project and assume specified risks, but only consumers or taxpayers can pay at the end of the day. This problem would have led to crisis one way or the other, with or without the Asian crisis. For example, in Pakistan, which was little affected by the crisis directly, unwillingness to raise consumer prices has led to payment problems for the public power utility, WAPDA. WAPDA saw its cashflow shrink, as IPPs received full cost covering prices, while consumer prices remained low. Malaysia’s power company, Tenaga, experienced similar problems before the crisis hit. With the crisis the problem is merely exacerbated: in Indonesia, for example, IPP tariffs range from 5.4 to 8.5 US cents/kwh, while consumer prices dropped to less than 2 cents after the crisis.

Thorough reform would dramatically change the nature of the financing challenge for developing country power systems. Suppose developing country governments set consumer prices at levels sufficient to cover all costs of existing assets, including the cost of capital. Suppose further that existing state-owned facilities were privatised, such that the performance of existing assets would be improved before buying new ones. The World Bank estimated in 1994 that this would generate sufficient cashflow on average via increased income (about US$ 85 billion) and increased efficiency (about US$ 30 billion) to pay for most if not all power investments planned (about US$ 100 to 125 billion) - without new borrowing.

**Allocation of market risk**

A second structural weakness concerns the allocation of market risk. Under typical long-term power purchase agreements the IPP is insulated from market risk, i.e. the shift in prices and quantity of electricity consumed. In other words equity and debt investors are contractually protected from such risk, whereas either consumer or taxpayers have to bear the full risk. But it is by no means clear that consumers or taxpayers are best placed to bear such risk in a crisis. In fact they would tend to be hardest hit in a crisis, whereas investors and speculators in particular are better able to diversify risk. For example in Oman, the country’s few taxpayers in a total population of 2 million are hardly best placed to diversify exchange rate and convertibility risk that they are made to bear under the power purchase agreement for the private El-Manah power station.

Market risk can best be shared with investors when there is real competition in a market rather than a regulated or contractually fixed price. Real competition in a market gives consumers choice, which in turn provides producers the incentive to innovate, provide better service and cut costs. The resulting spot price reflects customer choice and producer capabilities more accurately than prices negotiated by a monopoly utility, e.g. with an IPP.
The crises and trends in the cost of crude oil ing developing nations, which has been exposed by the current producers would be able to increase their market share and bring the markets, there is a much larger problem facing major oil export-restraint may hold up the price for a while. But in that case other domestic oil markets in terms similar to the discussion of power From the point of view of a country like Saudi Arabia, production In sum, reform options for power markets are available to policy-analysts come out with estimates that range from US$ 12/bbl to US$ for IPPs with long term power purchase agreements. patterns of production restraint by OPEC. particularly Saudi Arabia, States with up to 75 per cent debt - similar to the leverage achieved niow over where the long-run marginal cost of oil is - given current new merchant plants (generators taking market risk) in the United appreciation of the progress made in cost reduction. The debate is due to incomplete reform and unclear market rules, not to the intro-duction of markets per se. In fact, we now have seen the funding of new merchant plants (generators taking market risk) in the United States with up to 75 per cent debt - similar to the leverage achieved for IPPs with long term power purchase agreements.

In sum, reform options for power markets are available to policy-makers that would both improve short-term adjustment to future crises and most likely improve sector productivity. In fact, future financial crises would be rendered less likely by such reforms, since the large amount of explicit or implicit off-balance sheet government liabilities supporting private power deals would be heavily reduced, if not eradicated, and with them the incentive for private investors to take excessive risks.

Faultlines in oil markets

While one could discuss some regulated and state-dominated domestic oil markets in terms similar to the discussion of power markets, there is a much larger problem facing major oil exporting developing nations, which has been exposed by the current crisis. The cost of oil production is declining and with it the price. This in turn may undermine the rationale for production restraint for some major oil exporters.

The crises and trends in the cost of crude oil

Over the past 15 years or so, the cost of producing oil outside the low cost areas of the Middle East has declined. In 1986, when oil prices dropped by 50 per cent, it was thought that several high cost producing areas that were opened up under the umbrella of high oil prices during the late 1970s and early 1980s would need to be shut in again. North Sea oil production actually started declining in the late 1980s. However, cost-cutting efforts and innovations in exploration (e.g. 3-D seismic techniques) and production (e.g. horizontal drilling and new oil platform design) lowered costs sufficiently that production outside the OPEC area quickly recovered. Between 1990 and 1997, prices were kept up first by the production cuts following Iraq's invasion of Kuwait, and then by rapid world economic growth. As a result prices fluctuated around about US$ 20/bbl (Brent quality, 1998 US$). In early 1999, the precipitous decline in demand brought on by the Asian crises broke this trend, and prices collapsed to about US$ 11/bbl.

Box 2

What drives the price of oil?

The world crude oil price continues to be a function of significant production restraint by several oil exporters. Many of these belong to OPEC, most importantly Saudi Arabia, which could over several years ramp up production to, say, 20 million barrels/day instead of the current 8 million barrels/day, if it so chose. Production restraint by low cost oil producers necessitates the development of higher cost oil to satisfy the demand for oil. The cost of finding and developing the highest cost field needed to satisfy demand, including the capital costs, represents the long run marginal cost (LRMC) of oil, and sets the price for oil in the medium to longer term. So the LRMC of oil is a function both of demand and of production restraint. The price of oil can fluctuate heavily in the short run, but in the longer term, say over periods of 3 to 5 years, the price of oil will gravitate towards its LRMC.

This steep price drop surprised many observers and has led to the rediscovery of costs as a long-term driver of price and a renewed appreciation of the progress made in cost reduction. The debate is now over where the long-run marginal cost of oil is - given current patterns of production restraint by OPEC, particularly Saudi Arabia, and "sympathizers" such as Mexico and Norway. More and more analysts come out with estimates that range from US$ 12/bbl to US$ 17/bbl clustering around the mid-teens. For the next ten years there appear to be sufficient reserves available outside the OPEC area at these kinds of costs even if the world economy started to grow as fast again as it did in 1996 and 1997. In the longer run, conventional oil production outside OPEC will probably start to decline. However, significant quantities of substitutes such as heavy oils, shales, and tar sands, or gas-to-liquid technology, may become available at prices below US$ 20/bbl as technical progress has been significant in the development and exploitation of these substitutes.

Incentives to exercise production restraint

From the point of view of a country like Saudi Arabia, production restraint may hold up the price for a while. But in that case other producers would be able to increase their market share and bring the price back down as they cut costs. Several analyses now suggest that it would be in Saudi Arabia's economic interest to keep prices a bit below estimated marginal non-OPEC cost and to grab market share as the world economy recovers.

Saudi Arabia and other oil exporters have been hard hit by the crises and forced to consider their options carefully. Many oil-exporting countries are being badly hit by the current oil price collapse. Most have a weak economic base and are experiencing severe problems, from loss of external creditworthiness to internal unrest. Fewer and fewer countries will therefore have the incentive and the ability to preserve cartel discipline. As it is, most OPEC members honor production restraint agreements partially at best, although a new mini-cartel, consisting of the Gulf Co-operation Council (GCC) states, Venezuela, and Mexico, with Norway de facto playing along, is currently exercising some restraint.
As time goes by only Saudi Arabia and a few rich GCC states, principally the United Arab Emirates, will be capable of exercising some discipline. Yet Saudi Arabia is itself running a fiscal deficit and a balance of payments deficit in the order of 10 per cent of GDP at current oil prices. The government’s domestic debt has now reached about 100 per cent of GDP. At present, Saudi Arabia is still able to finance this deficit due to its huge underlying resource base. But new options are clearly being considered. Last year, in an unprecedented move, the government started eliciting investment proposals from North American oil companies.

In sum, oil prices may be on a continued downward trend due to technical progress. They could fall even further if key countries like Saudi Arabia decide to pursue market share over price defense. This would in turn tend to place downward pressure on prices of competing products such as natural gas and coal.

**The outlook after the Asian crises**

The Asian crises have highlighted underlying structural problems in electricity and oil markets. But what is actually likely to happen?

**Competitive power markets in Asia**

Over the last decade Asia was the continent of private greenfield investment in power projects, whereas privatization of existing assets and the introduction of real competition in power markets dominated in Europe and Latin America. Under fiscal pressure – which was also the driver in Latin America - several Asian economies have now announced programs to privatize existing power plants, and in some cases distribution assets. India, Indonesia, Korea, Malaysia, the Philippines and Thailand are in this group. While the fiscal pressures directly attributable to the crisis may recede, privatization momentum is likely to continue. In particular, the rapid aging of East Asian societies is likely to lead to mounting demands on the state and thus to maintain the attraction of privatization for the fiscal authorities.

The introduction of real competition in power markets may take more time and remain more spotty. Yet even here we can see change. In Australia, the States of Victoria and New South Wales have introduced competitive markets. Queensland is planning to follow suit. Singapore has introduced a basic power pool system. The Philippines have passed legislation for a wholesale power market. Japan and Korea are seriously considering similar reforms. The States of Orissa and Andhra Pradesh in India are moving towards private, competitive power markets. China has banned new firm off-take guarantees under power purchase agreements, and is planning to move towards a power pool system starting with a pilot scheme for the provinces of Shanghai, Shandong and Zhejiang by 2001. Indonesia has issued a policy statement calling for a competitive wholesale market. In Malaysia, the power utility Tenaga is trying to engineer new power purchase agreements to allow for re-negotiation if a competitive power market is introduced in the future. Judging by the time it took "reluctant" countries like Mexico to introduce competitive power markets, we could expect to see the wholesale competition in electricity markets in most major Asian countries by 2010.

**The erosion of oil prices**

More or less speedily, the remnants of production restraint under the OPEC regime are likely to erode further. Ten years from now, oil prices may be closer to ten dollars per barrel than to twenty (in money of 1998). The Middle Eastern producers may well expand market share. The pressure on higher cost producers would then become more intense. More and more countries would accede to domestic producer lobbies' requests to adjust tax regimes to maintain the profitability of the oil industry. Crude oil tax regimes may come to resemble normal corporate tax regimes in more and more countries. Foreign investors in exploration and production for oil and gas are likely to be routinely welcome in most countries, maybe even in Mexico and Saudi Arabia. Several countries may be tempted to privatize their national oil company, as Argentina did. At the same time, to extract maximum remaining oil rent, more and more countries may try to award new acreage for oil exploration and/or production by way of competitive auction (e.g. on the marginal tax rate) rather than by negotiation.

**Towards more integrated energy markets**

When oil prices continue to decline and competitive power markets are on the rise, the market for natural gas is likely to undergo more and more deregulation as well. In competitive power markets fuel prices will partly be a function of spot power prices. When oil prices drop gas use in dual-fired industrial and electricity facilities will probably become more responsive to tighter market conditions and prices may have to be set with greater regard to time and location. As regulatory barriers fall between energy sub-markets we may see a more and more integrated overall market for energy.

**A long term perspective**

**The last two decades**

**Twenty years ago:**

- There were oil price controls in the United States.
- Gas and power operations were highly regulated everywhere.
- A genuine world spot market for crude oil did not exist.

**Ten years ago:**

- Fairly efficient world crude oil and petroleum product markets had formed.
- Natural gas contracts in Europe and Asia were at least partially linked to spot prices in petroleum product markets.
- The US gas market was in the midst of deregulation.
- The first experiments with competitive electricity markets started.

**Today:**

- Crude oil and petroleum markets continue to expand.
- Gas-to-gas competition is a reality in the US and the United Kingdom.
- The EU gas directive has been passed and the first open access regimes are being introduced, e.g. in Holland.
- Competitive electricity markets have been or are being introduced in all major countries of North and South America, the UK, Scandinavia, Australia, New Zealand, and continental Europe.
Based on this record and the discussion in this essay, it is not implausible to expect the following changes for the next twenty years:

**The next two decades**

**Ten years from now:**
- The policy-induced barriers between energy sectors such as gas, power and petroleum products are disappearing.
- Techniques like slim-hole drilling and intelligent drills reduce the costs of crude oil production.
- New super cars become commercially available using only a third to half the energy needed today.
- New techniques such as high pressure pipelines and floating LNG facilities maintain the competitiveness of natural gas.
- Some type of competitive gas and power markets exist in all major countries of the world, maybe with the exception of countries in the CIS.
- Gas and power compete as the cheapest way to transport energy as high-voltage direct current transmission and some super-conductive transmission lines lower the cost of electricity transport.
- Micro-turbines and some form of fuel cells become competitive rendering distributed generation a reality in some uses.
- Better and better means of IT based electronic communication and control systems reduce energy losses and waste.
- Despite the low costs of traditional energy sources some renewable forms of energy are profitable in a number of niche markets, including in developing countries.
- More competition within and between energy sub-markets stimulates the development of new technology and new organizational solutions.

**Twenty years from now:**
- State-owned oil companies are a rarity.
- Oil equivalent to today's Brent quality costs about US$ 10/bbl (in money of 1998) as technological improvements mean that the exploitation even of heavy oil shales and tar sands is economic at this price.
- Few countries maintain special petroleum tax regimes.
- The distinctions between oil, gas and power companies have disappeared.
- New types of energy companies form, partly organized around customer solutions.
- The real price of energy has continued to drop.
- Energy efficiency is increasing rapidly as new building techniques and IT based control systems are introduced on a massive scale worldwide.

The Asian crisis of 1997/8 will be seen to have accelerated the move to more competitive energy markets.
The Impact of the Financial Crises on the Power Sector of Transition Countries

John Besant-Jones*

The Asian and Russian financial crises have dealt a double blow to the prospects for attracting private finance to the transition economies of Eastern Europe and Central Asia, just as many of the countries in this region were embarking on courageous reforms to their power sectors. This essay examines:

• The impact of the crises on attracting private investment to the sector under current reform strategies.
• The measures required to limit the short-term impact of these crises on reform strategies.
• Reform strategies for limiting exposure to future financial crises.

The essay begins with an overview of the present performance of the power sector, the sector reforms accomplished to date, and progress with sector privatization.

The power sector in transition countries: an overview

Present performance

The performance of the power sector in Eastern Europe and Central Asia has the following characteristics.

• Low quality of power supply, which is serious in the countries of the region, despite the persistence of excess supply capacity, and which is evidenced by frequent and prolonged power cuts in winters and severe drops in power system frequencies.

• Low operational efficiency and plant availability of power relative to good international standards, evidenced by relatively high fuel use per unit of energy output and low availability of most plants across the region.

• Low efficiency of electricity use relative to economic output, shown by the high electricity intensity of GDP in the region. In 1996, this ratio averaged 570 kWh per US$ of GDP for Central and Eastern Europe and 980 kWh per US$ of GDP for the FSU, compared to the average level of 320 kWh per US$ of GDP for the EU.

• High environmental damage from emissions of sulphur and nitrogen gases and ash dust from coal-fired power generating plants. This problem is worst in countries using indigenous lignite and/or brown coal such as Poland, Bulgaria, Kazakhstan, Romania and Hungary.

• Poor management and corporate governance in power utilities, in most countries. In the advanced transition countries of Eastern Europe, however, management and corporate governance approaches Western European standards.

• Inadequate electricity tariffs in many countries (except some Eastern European countries) to cover operating costs, generate internal funds for investment, and service new debt for investments or pay dividends. Household tariffs are subsidised, often by higher tariffs for industries. Tariffs have been increased sufficiently to cover variable operating costs in most of the region, but further improvements are required to raise maintenance standards, service debt and undertake capital investments.

• Low cash collection of revenues in many FSU countries (10% to 35%), as a result of the growth of non-monetary transactions in these economies. This is also due to governments’ use of power utilities to channel credit to loss-making heavy industries that are nevertheless economically and socially important, and to government entities suffering from budget constraints. This practice undermines the ability of power utilities to finance maintenance and capital works, and encourages non-recorded transactions.

The result is that power supply enterprises in most of these countries do not meet the financial performance standards necessary to access capital markets. The availability of sovereign guarantees is also declining due to the macroeconomic difficulties of many countries in the region. These countries therefore face an acute shortage of financial resources for the following investment priorities in their power sectors Box 1.

Box 1

Power sector investment priorities in transition economies

• Generation. Investments that reduce the high costs and harmful emissions from inefficient combustion of fuels. Pressure to improve fuel efficiency is greatest in countries that import most of their fuel for generating electricity. Pressure to reduce emissions is greatest in countries that use coal and lignite for generating electricity. Investment to increase generating capacity is not needed in most countries in the region because their installed capacities were sufficient to cover power demand that was 30% to 50% higher at the start of the 1990s than present levels. The choice is generally between rehabilitation and retrofitting existing plant with environmental controls, installing new boilers based on clean-coal technology, and constructing gas-fired gas turbines in open cycle or combined cycle modes. This choice applies to both power generation and to cogeneration of power and heat.

• Transmission and distribution. Investments to modernise communication facilities and system control and despatch facilities to reduce technical losses and increase power trade. Countries in Eastern Europe that intend to prepare for accession to the EU need to strengthen their transmission networks.
to meet the required technical standards.

- **Retail supply and demand management.** High returns are obtainable from relatively low investments in accurate metering and measuring equipment, especially at the wholesale level, and in computerised billing and collection systems. Demand-side management (DSM) is needed to deal with the growth in peak demand that is likely to accompany economic restructuring from heavy industries to light industries and commerce.

**Reform to date**

At the start of the 1990s, most electricity sectors in the region were structured as national or local monopolies and organised as departments of central government or municipalities. This has contributed to the poor performance noted in Section 2 above. To improve performance and meet investment priorities under tight constraints on public sector budgets, some governments want to attract private sector management and financing. This progress in reforming the organisation and regulation of their power sectors is summarized in Table 1.

**Table 1**

**Progress with power sector reform in transition countries**

<table>
<thead>
<tr>
<th>Reform stage</th>
<th>Countries</th>
</tr>
</thead>
<tbody>
<tr>
<td>No reform – integrated state-owned monopoly retained</td>
<td>Albania, Armenia, Azerbaijan, Belarus, Kyrgyzstan, Lithuania, Tajikistan, Turkmenistan, Uzbekistan, Croatia, Slovakia, Czech Republic, Macedonia FYR, Poland, Russian Federation, Ukraine, Latvia, Georgia, Hungary, Kazakhstan, Bulgaria, Estonia, Latvia, Moldova, Romania</td>
</tr>
<tr>
<td>Reform limited to concessions for private investors to sell to state-owned supplier of wholesale electricity</td>
<td></td>
</tr>
<tr>
<td>Reforms implemented, with private sector participation but market dominance by state-owned transmission/generation company; self-generation and third party access allowed</td>
<td></td>
</tr>
<tr>
<td>State-owned monopoly unbundled but little divestiture to the private sector; concessions allowed to sell directly to distribution companies and large users of electricity</td>
<td></td>
</tr>
<tr>
<td>Reform progressing radically through unbundling, independent regulator, divestiture and concessions, and nascent competition in wholesale supply</td>
<td></td>
</tr>
<tr>
<td>Radical reform being considered with enabling legislation enacted or in progress</td>
<td></td>
</tr>
</tbody>
</table>

**Table 2**

**Private investments in the power sector in transition countries**

<table>
<thead>
<tr>
<th>Country</th>
<th>Generation Plants and Companies</th>
<th>Distribution Companies</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hungary</td>
<td>Eight plants – majority</td>
<td>Six – large minorites</td>
</tr>
<tr>
<td>Poland</td>
<td>One greenfield IPP – fully private</td>
<td>None</td>
</tr>
<tr>
<td></td>
<td>One CHP – majority privatised</td>
<td>None</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>Two plants – majority</td>
<td>Two – majority</td>
</tr>
<tr>
<td>Kazakhstan</td>
<td>13 power plants –majority</td>
<td>One - minority (49%)</td>
</tr>
<tr>
<td>Estonia</td>
<td>None</td>
<td>One - majority</td>
</tr>
<tr>
<td>Georgia</td>
<td>Four under lease to employees</td>
<td>Nine - majority</td>
</tr>
<tr>
<td>Ukraine</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Russian Federation</td>
<td>One company – majority (integrated generation and distribution)</td>
<td>None</td>
</tr>
</tbody>
</table>

The full range of reforms is present in the region, including (i) unbundling without major divestiture; (ii) opening up the power market to new entry through concessions, including IPPs; (iii) divestiture without unbundling; and (iv) both unbundling and divestiture. It is too early to conclude that the region is definitely adopting a common reform model, as Asia has done through IPPs selling to dominant power suppliers, and Latin America has done through unbundling, independent regulation and wholesale privatization with IPPs selling to private customers. But there are indications that the region is leaning towards the Latin American approach. Many countries in Eastern Europe also want their power markets to comply with the 1996 European Electricity Directive and the EU environmental regulations as part of their strategy for gaining accession to the EU.

**Progress with privatization**

Privatization of the power sectors in the region is being achieved mainly in two ways: (i) sale of shares in state-owned power sup-
pliers or sale of their generation plants, with long-term investment and management commitments for the private shareholders; and (ii) concessions to invest in existing or new supply capacity to attract limited or non-recourse financing. Hungary and Kazakhstan have made most progress in the region, and other countries such as Poland, the Czech Republic, and Georgia have started to make progress. These countries have successfully attracted strategic investors who have brought financial, technical, and management resources into their power sectors. Distribution of shares through vouchers to management and employees has taken place in some countries (the Czech Republic, Ukraine, Russia), but it does not bring the benefits of private management and investment that is the basic objective of reform.

Only seven private power or co-generation projects, concentrated in four Eastern European countries, are being implemented under concessions or licences with non-recourse or limited recourse financing. Nine more similar projects, mostly in the same countries, have their key agreements in place and may reach financial closure. Table 2 lists the extent of private investment in the power sectors of the region to date.

The sale of assets (as opposed to distribution of small shareholdings) and the development of private power and co-generation projects in the region have thus made limited progress. The low level of divestitures and greenfield projects noted above contrasts unfavorably with the large number that have occurred in Asia (212) and Latin America (169) during the 1990s.

The basic causes of this slow progress in attracting private finance to the region are generally:

- Power tariffs below the levels needed to cover the financial payment obligations of off-takers.
- Low cash collections in many of the FSU countries, and high receivables and payables for power utilities.
- Significant foreign currency risks that cannot be mitigated through local currency finance because local capital markets are undeveloped. Indexing of tariffs to real exchange rates does not adequately solve this problem because of delays between tariff increases, billing and paying, and affordability constraints for power users.
- Unavailability of commercial loans on long tenors and affordable interest rates.
- Delays in passing legislation that permits concessions for public services.
- Unstable regulatory environments that have been neither developed nor tested.
- Discriminatory taxation practices against foreign investors.
- Unfamiliarity of local participants with the concept of project financing and the complexities of the agreements.
- Unsound privatization strategies that fail to give priority to attracting strategic investors.
- Lack of urgency of acquiring new generation capacity in most countries.

This generalisation applies variably across the region. It applies with least force in the advanced transition countries of Eastern Europe. Moreover, this progress is focused on the countries that have progressed furthest with overall economic reform, Kazakhstan and Georgia excepted (Box 2).

**Box 2**

**Privatization of power in Kazakhstan**

A large amount of Kazakh power capacity has been allocated to private operators through a series of closed tenders, often with limited transparency. Most of the sales yielded a low price that reflected high commercial and political risk, but they carried investment and management obligations on the part of the new owners in deferred maintenance and upgrades. Rather than focus on maximising the proceeds of privatization, government chose this way of disposal with the primary objective of improving the quality of power supply. This priority is shown by the case of the Ekibastuz Gres 1 coal-fired generation plant, one of the first power plants in the country to be sold to a western utility. The plant has a nominal capacity of 4000MW, but only one unit of about 200MW of capacity was available for use before the plant was privatised.

**Impacts of the financial crises**

The Asian financial crisis has called into question the generally adopted Asian strategy of attracting private financing by means of IPPs selling to a national power utility. Under this strategy, project financing for these IPPs is typically secured against long-term off-take agreements with these utilities, backed by government undertakings on the performance of state-owned parties to the project transactions. Asian countries have used this approach to introduce private investment to the power sector in the absence of a formal regulatory framework and before the start of sector restructuring. The contractual commitments for IPPs act as proxy sector regulation, and IPP security structures cover the market risks for lenders.

IPP contracts contain some in-built flexibility to deal with variations in market conditions during the terms of the contracts. However, this flexibility could not accommodate the shocks imposed on the IPPs by the major currency devaluations that triggered the Asian financial crisis. The most vulnerable IPPs were those with (i) the maximum exposure to devaluation risk, through heavy reliance on foreign financing and imported fuel, and (ii) sales agreements with power utilities whose retail tariffs were well below levels needed to recover supply costs fully. The terms of these off-take contracts became unenforceable, and thus assumed an uncertain duration under the risk of macro-economic crises. This uncertainty is highly disturbing to financiers, since it implies that no amount of financial engineering to allocate risks could enable these contracts to remain intact under certain circumstances. More fundamental shock absorbers need to be built into the design of sector structures.

The Russian financial crisis has increased the difficulty of attracting private finance to the power sector across the region. It has had least impact in the advanced transition countries of Eastern Europe, partly because their prospects for accession to the EU is expected to encourage their governments to follow sound macro-economic policies and adhere to the requirements of the EU Electricity Directive.

In Eastern Europe, the financial crises have cooled the growing interest of international commercial banks in staking market footholds, rather than turning them away. Before the crises, these
lenders were offering attractive terms – spreads of less than 100 basis points over LIBOR and tenor of more than ten years - for private power investments. Some of these banks even considered lending for the development of a power generation project on a merchant basis in Hungary, in which the project would not have the security of a long-term power sales agreement to reduce the market risk for the investment.

In contrast, the countries most vulnerable to the Russian crisis, generally those in the FSU, have experienced a virtual loss of access to commercial funding on terms affordable for project financing. This is because their country risk rating deteriorated following the decline in their exports to Russia, which has aggravated their already difficult environments for investors. Hence IFIs and ECAs are presently the sole sources of debt funding for private power projects in these countries. Since the latter often require the presence of an IFI in the financing plan as a condition of their participation, the IFIs have a key role in mobilising finance for these projects.

**Mitigating investors' concerns**

In spite of the difficulties in attracting private financing and management, well-capitalised and experienced strategic investors will still be attracted to sound investment opportunities in the power markets of the region. The indication that there is a regional inclination to unbundle the power market, regulate monopolistic services, and privatise the entities that operate in the competitive segments of the market, will help to capture this interest. This approach gives governments the opportunity to develop the market structure and privatization process in ways that strengthen the security structures for these investors. These ways are illustrated below for the cases of promoting competition in the generation sector through IPPs, and of meeting the concerns of strategic investors in the privatization of the distribution sector.

**Using IPPs to promote competition**

The Asian experience suggests that successful development of the first IPPs can mislead governments into concluding that reforms to their power sectors need go no further: so the first consideration in using IPPs to promote competition is how to avoid using them in ways that stifle competition. In fact, governments should limit the number of IPPs that are allowed to off-load their market risk through long-term contracts with a national power utility, both to control vulnerability to external shocks, as noted above, and to allow the unbundling of the utility under further stages of reform without the complexity of re-assigning numerous off-take agreements.

The first IPPs in a country can be used to stimulate the development of the required legislation and regulations for private finance in the power sector of transition economies, as well as familiarising policy makers and sector managers with market-oriented commercial and financial transactions. But the difficulty of introducing private investment before restructuring and regulating the sector is shown by the lengthy periods – typically up to five years – to reach financial closure on initial IPPs.

The transition impact of IPPs is increased when they are introduced after a sector has been unbundled and regulation provides a competitive process for granting long-term concessions for new power capacity, as shown by Hungary’s experience with its capacity bidding program (Box 3).

**Box 3**

**Hungary: competitive tender for new power capacity**

Hungary has adopted an unbundled power structure in which MVM - the national power transmission company - acts as a Single Buyer by purchasing electricity from generators and selling it on to distribution companies. Competition in the wholesale power market is for the right to sell electricity to MVM under long-term power sales agreements. MVM launched its first round of tenders for new capacity in late 1997. It invited tenders for a total capacity of between 700MW and 1500MW. MVM received 33 final complete bids amounting to 15,000MW. MVM accepted the lowest evaluated bids for two plants for a total capacity of 400MW. The prices in the winning bids were equivalent to 3.0-3.2 cents/kWh.

Hungary is now moving towards retail liberalization and third party access for large industrial consumers, and in the future will use the authorization rather than the tendering procedure for new capacity – eliminating the requirement for a long term PPA with the publicly-owned single buyer.

The security structures of the first IPPs can be improved by obliging the utility to allow third party access to its transmission and distribution networks. This would allow private investors to conclude sales agreements for IPPs with credit-worthy large users of power, as with most IPPs in Latin America. These IPPs can be developed as co-generation plants to sell both heat and power to industrial plants that earn revenues – preferably in foreign currencies from exports – that lenders accept as pledges. Concessions for CHP plants can also mitigate the concerns of investors and financiers over a major economic shock to project agreements such as large devaluation, because host governments are likely to help resolve problems for these plants on account of the social importance of meeting district heating needs.

Development of IPPs by co-generation and CHP plants with third party access advances the reform of power sectors by introducing competition for some of the utility’s most lucrative market. Improving their energy efficiencies are also important for countries that rely on imported fuels, as most do in the region. This puts financial pressure on the utility to abandon cross-subsidies for some consumer groups, especially under falling or slow growth in demand for power as may result in FSU countries from the Russian financial crisis. Under pressure in the competitive generation and supply markets, the utility may then become an advocate of more radical reform.

IPPs can be concluded directly with suppliers and large energy users in a competitive market and with much lower government performance guarantees after implementation of structural and regulatory reforms to the sector. Merchant power plants that are not exposed to any contract-based risks may start to appear in the region when investors are confident that their plants will be despatched in preference to high cost and polluting old generat-
ing plant without the protection of long-term power sales agreements (PSAs). Such merchant plants would have to be financed with a higher proportion of equity (30-50%) than is used to finance IPPs with long-term PSAs (20-30%). Their investors would also want to hedge the medium term price risks for power sales and fuel purchases for merchant plants, and these instruments are only likely to become available in the next few years in the countries of Eastern Europe.

**Privatising distribution entities**

The region’s mixed record of success in privatising power entities reflects the constraints placed by governments on investors, as well as difficulties in the financial markets. Governments could facilitate privatization even under these difficulties by removing these constraints. In the case of privatization of distribution entities, typical constraints that are applied in the region can be removed as follows:

- Conduct tenders for shares in a way that facilitates the participation of strategic investors. Tenders should be widely announced, tender documents made easily available, and bid securities accepted as letters of credit rather than requiring cash.
- Offer a sufficiently large package of shares for privatization to give the strategic investor a controlling interest in a power entity. Control that depends on a Power of Attorney over the voting rights to the state’s shares in place of selling majority ownership is unlikely to be sufficient to attract many strategic investors.
- Limit the requirement to undertake specific investments in the privatized company as a condition of privatization.
- Establish a payment settlement mechanism for the wholesale power market that enables distribution companies manage their cash collections.
- Use sound regulatory processes for formulating electricity tariffs, approving regulated tariffs, and allowing justifiable costs to be passed through to the tariffs, in accordance with franchise licenses for distribution companies.
- Progressively open the electricity supply function to competition whilst keeping the distribution service function under regulation.
- Avoid giving discounts in tariffs to groups of power consumers and restricting the disconnection of persistent non-payers, without establishing reliable mechanisms for reimbursing distribution companies for the loss of revenues.
- Enable investments in power entities to qualify for protection under foreign investment protection legislation.
- Ensure that tax legislation treats depreciation, interest and dividends according to norms based on international accounting standards and without discrimination against foreign investors.
- Allow foreign arbitration of disputes under share purchase agreements, preferably according to an internationally recognised mechanism such as the ICSID Convention.
- Protect newly privatised entities from legal action brought by creditors to allow new managers time to restructure debts run up by the previous managers.

**Robust reform strategies**

Governments have a number of options for making their reform strategies more robust to financial crises. The main options are: (i) to privatise the distribution and supply sector before privatising the generation sector; and (ii) to allow alternative trading arrangements for wholesale power.

**Order of privatization**

In a situation where the priority is to improve quality of service, payment discipline, non-commercial losses or cash collection, as it is in many countries of the FSU, the private sector should be introduced to supply (and thus distribution) before other parts of the power sector. The increase in cashflow up the power supply chain that will follow from these improvements, will enhance the value of generation assets that are to be privatised.

Distribution franchises in these countries are likely to be saleable only at US$ 50 – 100 per customer, which is a fraction of the prices of US$ 1,000 – 1,500 per customer obtained from the sale of distribution companies in Latin America. Investors will be attracted by this high risk/high reward trade-off, as it offers huge potential for increasing the value of the business by raising cash collection rates (as has already happened from the privatisation of the power system in Almaty, Kazakhstan). Where there are legal impediments to divestiture, the billing and collection and other customer services could be conceded to private management until these impediments are removed. The selected approach to introducing private management to distribution should not conflict with the aim of introducing competition in the power market. For example, the terms of initial private involvement in supply and distribution should not provide for an indefinite continuation of a monopoly in supply to the whole market covered by the distribution franchise.

**Wholesale power trading arrangements**

The trading structure of the wholesale power market should facilitate competition, promote payment discipline, and allow fair recovery of operating and investment costs. It should be supported by appropriate regulation. Various trading structures are being considered by countries in the region, and they meet this criterion to the following extent:

- A power pool that allows bidding from both suppliers and users offers the greatest scope for competition in principle, but requires sophisticated legal and financial frameworks that are unlikely to develop in the region for the foreseeable future.
- A power pool in which market clearing prices are based on offers to supply by generators, is vulnerable to influential generators and political interference. It thus requires the presence of a substantial number of private generators, suppliers and large users, which is only feasible in the larger power systems of the region.
- Direct trading in wholesale power between generators and suppliers or large users has the best potential to attract private investment. Concessions in this market should be awarded competitively in order to keep down the cost of energy that is passed through to retail tariffs.
- Trading through a single buyer, where generators transact only with an intermediary that in turn transacts with suppliers and large users, incurs the risk of government intervention to cap prices and protect favoured users and regions from supply cut-offs for non-payment. A single buyer system can also be manipulated by distribution companies and large users of electricity to settle their accounts in barter (as occurs in some of the FSU...
countries) rather than in cash. These prospects will deter investors. This arrangement is therefore unlikely to be suitable in practice as the only trading mechanism in a power market.

It is essential that proper accounting and management systems are installed and in use in power generation companies before a competitive power pool is introduced. Otherwise, the operation of power pools will presently be distorted by bidding that is unrelated to power production costs, because managers do not have a proper understanding of these costs for their power plants. This would lead to uneconomic despatch of plants out of the real merit order, and increase the risk of under-recovery of investment costs for new plant.

Combinations of the above approaches are also feasible. Modified pool arrangements for supply-side bidding only may be a workable compromise for attracting private investors to the region's power sectors, provided that they allow a major degree of bilateral trading between generators and suppliers. A single buyer and seller of wholesale energy may be useful for the balance of trades in the market from bilateral contracts, or as an interim arrangement until the legal, regulatory and financial systems become sufficiently credible in the countries of the region to support competitive trading under pool arrangements. The risk with this strategy, however, is that it may enable reactionary elements that are against reform to block the further reforms necessary for promoting competition.
Oil Prices: Recent Trends and Forecasts

Shane Streifel*

The recent steep decline in oil prices reflects the fall in global demand due to the financial crises, and shifts in underlying oil market conditions due to the price cycle, environmental concerns, and new fuel technologies. This essay:

- Reviews the longer-term trends in oil prices.
- Analyzes the prospects for oil prices over the next few years.
- Evaluates the overall impact of the oil price collapse on developing countries and the oil industry at large.

Oil exporting developing countries are facing the major drop in government revenue; but the fall in energy prices is an antidote to the macroeconomic downturn for oil importers.

Global economic context

In 1998, oil prices fell by 32% or US$ 6/bbl to US$ 13/bbl. This latest decline was due to rising oil production, weak demand in Asia, and soaring inventories. More broadly, oil prices have fallen from a peak of US$ 25/bbl in early 1997 to under US$ 10 in December 1998 (Figure 1). In real terms, prices are at their lowest levels in more than 25 years.

Five oil producers—Algeria, Iran, Mexico, Saudi Arabia, and Venezuela—agreed in March 1999 to reduce output by more than 2 mb/d, or 2.7% of world demand. If ratified by OPEC it would help reduce inventories and raise prices. Should the agreement be derailed for a protracted period, the supply overhang could continue for several months and prices would remain low. A key factor will be demand.

Figure 1

World GDP growth in 1998 slowed to 1.8% from 3.2% in 1997. Global output is expected to slow further this year, but is being supported, in part, by the strength of the US economy. While some East Asian economies are starting to turn around, there is little likelihood of improvement in most developing countries in 1999. The crisis in Brazil is leading to negative economic growth in Latin America this year, and the Russian financial crisis has led to a severe reduction in output in Russia and other CIS countries. A return to trend growth rates is unlikely in many countries before 2001, and it is unlikely East Asian economies will return to their extremely rapid rates of growth of the early 1990s.

Assuming no global meltdown, world GDP is expected to increase by more than 2% in 2000, possibly returning to growth of 3% in 2002 and beyond.

In addition to oil, prices for most primary commodities have been falling in recent years, including those for most minerals, metals, food and agriculture products, but also other energy products, such as natural gas and coal, in part because of their link to oil prices. The large declines in commodity prices have been caused by the slump in East Asian demand and steady increases in supply. Many commodity prices—including oil—were falling before the Asian financial crisis, mainly due to large increases in supply which have resulted from significant advances in technology, falling costs of production, and previously high prices. In addition, market liberalization and privatization have provided greater incentives for investment and wider adoption of new technologies. Because of these advances, commodities may be experiencing a structural break in price levels, and may not fully recover from current low levels.

Oil price forecasts: impact on OPEC and non-OPEC supplies

Since 1973, oil prices have been kept well above the costs of production because of output restraint by OPEC countries. Prior to the quadrupling of oil prices in 1973/74, OPEC was raising production by 10% per year. Its output plateaued at little more than 30 mb/d during the second half of the 1970s, before plunging in the early 1980s due to falling demand, but also because of output

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restraint to sustain high prices (Figure 2). When Saudi Arabia was on the verge of being driven out of the market in 1985, it raised production and prices collapsed in 1986. In the second half of the 1980s, OPEC benefited from the rebound in demand and declines in production in countries such as the US and UK. But in the 1990s, its production has grown more slowly due to significant increases in non-OPEC supply.

Figure 2
OPEC crude oil production

OPEC's production has not returned to its previous peak of the 1970s, partly due to its self-imposed production restraint to target prices in the range of US$ 18-US $21/bbl. In the 1990s, Saudi Arabia's production has remained at about 8 mb/d, except for the period in late-1997/early-1998 when it first raised and then reduced production. Despite robust growth in oil consumption during the 1990-97 period, all of the incremental demand was captured by other OPEC and non-OPEC producers. There have been sizable increases in non-OPEC supply due to relatively high levels of investment, declining costs, and significant advances in technology, e.g., horizontal drilling, 3-D seismic modeling, floating production systems, and unmanned subsea completions. In the North Sea, where these developments have been particularly prominent, the large infrastructure in place allows the development of marginal fields at low cost, often through directional drilling. As shown below, non-OPEC supplies outside of the US and countries of the former centrally planned economies rose by more than 5% per year over the 1970-1998 period.

OPEC, Other Former CPEs * US

A problem for OPEC under this scenario is that high prices re-ignite previous problems, mainly significant increases in non-OPEC supplies and limited growth in demand for OPEC crude. While OPEC may capture a significant portion of the growth in oil demand under a "US$ 20 price scenario" there may not be sufficient volumes to satisfy the needs of all producers. Depending on OPEC production sharing practices, a situation could again arise in which there is little residual growth for Saudi Arabia, similar to what has transpired since 1990. To raise market share and curb the growth of non-OPEC supplies, lower prices would be necessary.

Should oil prices fall toward US$ 10/bbl on a sustained basis, the demand for OPEC oil would rise much faster than if oil prices were at US$ 20/bbl. Non-OPEC supply growth would be curtailed in the short-to-medium term as development investment falls, but this would be partly offset over time by further reductions in costs and advances in technology. Also, governments will be pressured to lower taxes and royalties to stimulate investment, and there will be increased competition among countries to attract the dwindling capital of foreign companies.

Impact of low prices

On oil importing and exporting countries

Low oil prices have affected both oil importing and exporting countries. Oil importers benefit greatly from the drop in oil prices, especially developing countries, through reduced foreign exchange requirements and lower input costs to industry and consumers, depending on domestic pricing policies. In the industrialized economies, which have been running at near full capacity, lower oil prices have contributed to low inflation and interest rates and have helped sustain robust, consumer-led economic growth.
Oil exporters, on the other hand, have been particularly hard hit by the plunge in oil revenues and have suffered from deteriorating current account balances and much weaker GDP growth. In the oil-dominant countries, some drawdown of financial reserves is expected, particularly in the Gulf countries, and new external borrowing will be required by other exporters. Although countries in the Middle East and North Africa have attracted growing foreign direct investment and portfolio flows—from very low levels—these will not be sufficient to cover the increase in current account deficits. But because stock markets are not very developed and have little foreign participation, they are generally not exposed to the effects of the Asian financial crisis felt by other emerging markets.

Overall, the benefits of lower prices to the global economy appear to outweigh the costs to oil exporters, even though the impact on the latter has been severe. In a sense, the effects are the opposite of the oil price shocks of the 1970s when oil-producing countries benefited at the expense of the world economy. Due to improved energy efficiency—a product of previous price shocks—the benefits are less noticeable, but the transfer of wealth to oil importing countries has helped sustain economic activity in industrialized countries and has tended to cushion the effects of the financial crises in Asia and, more recently, Brazil.

On non-OPEC Production

With regard to the oil market, low oil prices have already started to affect non-OPEC production, particularly in high-cost areas (US and Canada) or low productivity areas (US stripper wells). Most existing production, however, will not be shut-in should prices fall under US$ 10/bbl because marginal operating costs for most of the world’s conventional oil production is at or below US$ 4/bbl, and in many cases well below. Because of the costs of shutting-in and re-starting production, and because of expectations that prices will recover, prices may have to fall substantially below the marginal costs of production before any large-scale volumes would be "lost".

On new production

New oil developments will not necessarily be curtailed either because of low oil prices, as development costs for most of the world’s conventional oil development are below US$ 6/bbl. Again, costs in many areas are well below this level, depending on the size of the resource development and access to market. In the North Sea, for example, the vast infrastructure in place allows the development of marginal fields at low cost, through directional drilling tied into existing platforms and pipelines.

On exploration

Low oil prices will, however, cause a reduction in the investment needs to replace and develop oil reserves. Most upstream development in the petroleum industry is financed from cash flow; thus, reduced revenues will result in lower upstream investment, which will ultimately result in lower oil production. In 1998, upstream capital expenditures fell only moderately, partly because expenditures were allocated before the collapse in prices, and because of expectations that oil prices would improve rather than plunge late in the year. For 1999, however, capital expendi-

ures have been cut dramatically because of reduced cash flow and expectations of a limited recovery in prices.

On the industry

The petroleum industry is responding to low prices by cutting costs to maintain profitability. The recent rise in merger activity partly reflects a desire by companies to reduce unit costs and increase value to shareholders. While further across-the-board cost reductions can be expected, the industry will continue to develop new technologies to reduce exploration, development and production costs, despite an implied reduction in research and development expenditures. It is possible that the tremendous technological advances seen over the past decade could accelerate under a lower price environment, as companies are pressured to reduce costs and raise productivity.

On consumption

On the demand side, lower prices will have a limited impact on oil consumption in the short term due to the low price elasticity of demand. In some countries, the tax component of retail gasoline prices is around 80%, such that the percentage change in retail prices is much less than the percentage change in crude oil prices. In some developing countries petroleum product prices are regulated, and demand will be affected to the extent that prices are passed on to consumers. Low oil prices will enhance economic activity of oil importers, as trade balances improve and income is freed up for other uses. This benefit will be tempered, however, in countries whose currencies have depreciated. In oil exporting countries, low prices have adversely affected economic activity, and thus oil demand is also affected negatively. To the extent that end-user prices change, oil demand will be inversely affected. In countries where subsidies still exist, financial pressures may lead to a reduction in subsidies and lower oil demand.

World Bank oil price forecast

The World Bank forecast assumes oil prices remaining low (i.e., US$ 10-13/bbl range) until inventories are reduced and global demand recovers. Assuming some supply management by OPEC, oil prices are expected to recover to US$ 15/bbl in 2000, and increase modestly thereafter. But this depends critically on continued supply restraint by OPEC producers and a desire for higher prices. Oil prices will remain volatile because the organization typically sets production levels for 6-12 months. Thus fluctuations in supply, demand, and inventories, are transferred directly into price changes. Should oil prices return to the upper "teens", they will again come under downward pressure due to rising non-OPEC supplies, increasing competition, and the difficulty of allocating production among OPEC producers. Prices above US$ 20/bbl are thought unlikely, as falling costs of non-conventional oil production and competing fuels will effectively put a ceiling on long-term oil prices - although supply shocks remain possible.
The Asian financial crisis has exposed inherent weaknesses in the institutional and financial structure of the energy sector in several East Asian countries – weaknesses which were not apparent while energy demand and the economy were expanding rapidly. Along with a number of other countries in the region, Thailand is seizing the opportunity for reform. Its plan is based on its experience that:

- Deregulated markets have coped best with the crisis.
- Best practice private sector investment has also been able to cope with the turmoil.
- Outdated laws and regulations have made the situation worse.

Reform must fairly balance the interests of producers with those of consumers: pressure from consumers will become a major factor in pushing forward the privatization and deregulation of the energy sector.

Sectoral context

Prior to the global financial crisis, the energy sectors of most East Asian countries were characterized by the following, common features:

- **High growth of energy demand**, as shown in Box 1, is due to rapid economic growth, increasing industrialization and urbanization. Financial constraints and policies to promote competition have gradually increased the role of the private sector over the years. Very rarely, however, was the market completely open to investment without any control by the government on capacity expansion or through licensing.

- **Energy prices** are only partially deregulated and in many countries prices are still tightly controlled by the government. There are exceptions, for instance, Thailand and the Philippines have deregulated oil prices. In the case of electricity, for which tariffs have to be regulated anyway even in developed economies, prices are controlled or regulated by the government rather than by independent regulatory bodies which tends to politicize pricing issues.

- **Exchange rates** were fixed with few exceptions. Changes in the exchange rate or the introduction of floating exchange rate regimes were rarely contemplated. This provided stability for a while, but also sent the wrong signals for investment decisions. The risk of any change in the exchange rate was perceived to be negligible, and as a result bankers were prepared to finance projects in US dollars with income from electricity sales in Thai baht.

- **Deregulation and Privatization** of the energy sector in most East Asian countries has only recently started. In the case of Thailand, when the global financial crisis occurred, most IPPs had not come to financial closure. Moreover, the deregulation process was just in its initial phase with many steps to be implemented before full competition could be achieved.

Local capital markets were relatively undeveloped making project financing extremely difficult without relying on foreign funds; many financial instruments taken for granted in developed economies simply did not exist. Financing of private power projects, therefore, was only possible for projects whose incomes were fairly predictable -- for example, projects with firm, long-term, offtake agreements; financing a merchant plant would have been extremely difficult.

**Box 1**

**Before the crisis: high growth of energy demand**

Thailand experienced an annual growth in primary energy demand of 8.9% during the period 1990-97 whereas the demand for electric power grew by 14.1% per year over the same period representing an average additional capacity requirement of 1,100MW per annum. South Korea also experienced similarly high growth rates: primary energy consumption grew by 9.8% per year on average during the period 1990-97. With the rapid growth in energy demand, the primary objective of energy policy was to procure a sufficient amount of energy to meet the increasing demand, and this was done mainly through investments on the supply side: power generation, transmission and distribution systems, oil refining and marketing as well as natural gas production and pipeline network.

**The impact of the crisis**

The global financial crisis has had a severe impact on the energy sectors of East Asian countries in the following ways:

- **Negative economic growth** was recorded for the first time in decades with energy demand actually falling in many cases as shown in Box 2.

- **Devaluation** of the exchange rate against the US dollar has pushed up the cost of energy in local currencies. The problem

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was particularly serious up until early 1998 as oil prices were relatively strong and the movement in the exchange rate was erratic. Although the problem has been alleviated by more stable and stronger exchange rates, together with the drop in US dollar oil prices, prices in local currencies in some cases are still higher than before the global financial crisis (Table 1).

### Table 1

**Price of crude oil (per barrel)**

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<th>Pre-crisis</th>
<th>During Crisis</th>
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**Financing Difficulties.** Deterioration in the financial markets not only disrupted the normal operations of the energy sector, but also had a substantial impact on the implementation of existing investment programs and lending for new investment projects. In Thailand, Indonesia, and South Korea, the local financial systems were on the verge of collapse with a large portion of domestic credit disappearing due to the insolvency of local financial institutions. Given the relatively fixed exchange rate regime before the crisis many energy-related entities borrowed heavily in foreign currencies to finance long-term projects whose incomes were in local currencies; moreover, a large part of the borrowing was in the form of short-term loans. When the financial crisis occurred, these energy-related entities were suddenly faced with rapidly rising foreign debt and interest repayment in local currency and the disappearance of a portion of credit normally extended by financial institutions. Constraints in the financial markets also made it difficult for governments to raise long-term borrowing to finance infrastructure projects. Before the global financial crisis, government-owned public utilities could borrow relatively easily on favorable terms; that is no longer the case. The financial solvency of government-owned electric utilities has since become a major concern for institutions which are financing IPP projects.

**Box 2**

**Impact of the crisis: energy demand collapses**

Thailand’s primary commercial energy consumption fell by 7.0% in 1998, and power demand declined by 2.4%. South Korea and Indonesia had similar experiences. Primary energy consumption of South Korea is estimated to have fallen by 5% in 1998 with electricity consumption falling by 2%. In Indonesia the demand for oil declined by 5.3% while the demand for electricity grew by just over 4% in 1998. Prospects for 1999 and beyond are also not good: even the optimists are forecasting economic growth for the next 5 years well below the growth forecasts before the crisis. With rapid energy demand growth and huge investment expenditures before the crisis, an excess demand for energy in 1997 has suddenly turned into an enormous excess supply. For instance, the annual reserve margin of Thailand’s power system, which averaged 8.6% during the period 1990-97, is expected to rise to nearly 50% in 2000. The excess demand of natural gas which required the rapid the conclusion of various gas supply agreements during the period 1992-96 has developed into a surplus with the need to delay various natural gas schemes.

Viability of Investment Projects. The repercussions from the crisis have raised the cost of new investment capital to energy-related enterprises, as well as of the repayment of existing foreign and local debt. In certain cases, the problem is compounded by the deterioration in the business environment – for example, the decline in global energy demand. Moreover, electric utilities in a number of countries were not able to make sufficient tariff adjustments and this further weakened their financial positions. All IPP projects in Thailand, which had earlier signed power purchase agreements with EGAT with tariff income in Thai baht, found their projects to be no longer feasible.

**Policy responses**

What have been the responses to the impact of the global financial crisis? In all countries, the major policy prescriptions are very similar: reduction of investment on the supply side, price adjustments, acceleration of privatization and deregulation, and renegotiation of specific contracts.

**Investment on the supply side** has been sharply reduced wherever possible as described in Box 3.

**Box 3**

**Rescheduling investment**

In Thailand, all supply side negotiations which had not been committed before the crisis have been indefinitely or substantially delayed. These include an indefinite postponement of the LNG supply agreement with Oman, a substantial delay in the natural gas supply agreement from Natuna (Indonesia), a few years delay in the gas purchase from Thailand-Malaysia Joint Development Area and 3-5 years delay in about 2,700MW of power purchase from projects in the Laos PDR. Projects with commitments have also been "renegotiated", and the commercial operation dates for about 40 private power projects have been delayed by between 3 months and 4 years. Investments by state-owned enterprises have also been delayed or cancelled. Projects in transmission and distribution have been delayed in line with lower demand, and EGAT has cancelled a number of generation projects: for example, the 2,000MW Tab Sakae power plant and Thermal Units 3-4 at Ratchaburi. The natural gas pipeline network has also been scaled down, so that, for example, the third pipeline from the Gulf of Thailand had been postponed indefinitely.

The picture is similar in Indonesia and South Korea. In South Korea, the completion dates of 60 power plants under construction are being delayed by more than 3 months. The delayed capacity is around 17,435MW with an average of 15 months delay period. The natural gas industry has also revised its investment plan with a reduction of around 50% in investment expenditure.

**Adjustments to Energy Prices.** Both oil prices and electricity tariffs in local currencies have increased from the pre-crisis level. Where the energy price had already been deregulated, as in Thailand, the adjustment in prices has been generally easier. In Indonesia, where oil prices were controlled by the government, the political and social repercussions from the adjustment were much stronger. With economic recession a reality and unemployment rising rapidly, energy users have had little stomach for
explanations from the government for energy price hikes; the fact that it is government which controls prices has tended to complicate the issue even further. Traditional price-setting mechanisms lead to a higher electricity tariff as demand falls and over-capacity is developed so that the financial performance of the electric utilities is maintained often to meet the requirements of the financial covenants agreed to with lenders like the World Bank. In a competitive commodity market, or a competitive electricity market, prices should fall as excess capacity is developed and not rise as we have seen. This downward pressure would lead to greater pressure for a more rapid reform of the energy sector and the introduction of measures to increase efficiency.

Privatization and deregulation of the energy sector are being accelerated. The crisis has increased the government’s fiscal incentive to privatize, and has also put more pressure on deregulation and the creation of competition in order to provide consumers with lower prices and higher service quality (Box 4). Depressed capital markets, however, have also meant that privatization has had to rely much more on foreign strategic investors than on public offerings which makes resistance to privatization much stronger due to nationalist sentiment.

Box 4
Financial crisis – stimulus for reform?

Thailand, South Korea and Indonesia have all announced clear long term plans for the deregulation and privatization of the energy sectors. Moreover, there seems to be more political will to push through the necessary reform.

Thailand announced a transparent target for the deregulation of the power supply industry in September 1998, clearly indicating a desire to separate electricity generation from transmission so that a power pool and retail competition could be introduced in 2003. The government has also continued to move forward forcefully in the privatization of existing generation assets of EGAT with a further sale of EGAT’s shareholding in ECGO to China Light and Power in 1998, and a plan to privatize the 3,200MW Ratchaburi power plant in 1999. The natural gas deregulation plan was also recently announced which combines the separation of the Petroleum Authority of Thailand’s gas transmission operation from its gas trading activity with the introduction of third party access by 2000, and private investment in new natural gas transmission projects.

South Korea announced a privatization initiative in July 1998, including the sale of 11 publicly-owned companies, KEPCO and KOGAS among them. Privatization will be accompanied by deregulation including removal of entry barriers at all levels, ensuring open access and import.

Indonesia also announced a policy to restructure the power sector in August 1998, with PLN being unbundled into independent units in generation, transmission and distribution.

Contract renegotiation and debt restructuring. Any project with foreign loans but income in local currency is unlikely to survive unless the contract is renegotiated and the debt restructured. Even government-owned enterprises found the terms and conditions for new borrowing worsen substantially in line with the rise in sovereign credit risk. New debt instruments had to be found, e.g. US$ 300 million bond issue by EGAT with principle guaranteed by the World Bank and interest payments guaranteed by the government of Thailand. The bond was successfully issued in September 1998 with an interest rate of about 2.87% above US Treasury bills compared with the Thai government bond which at the time was trading in the international money market at around 7% above US Treasury bills.

Before the crisis, all PPAs between EGAT and private power producers were denominated in Thai baht, because the foreign exchange risk was perceived to be negligible. In order to make the projects viable after devaluation, the PPAs were renegotiated by indexing a portion of the capacity payment to the exchange rate, with the developers absorbing a part of the foreign exchange risk, and various non-price terms in the PPAs were amended to bring the PPAs into line with best practice principles. This was negotiated together with the delays in the commercial operation dates. Since the shareholders had to absorb a portion of the impact and a number of Thai companies were also faced with financial problems, there has been considerable changes in shareholding structures of private power projects with foreign shareholding rising substantially.

Lessons of the crisis

In implementing the needed reform, social and political constraints, as well as legal and institutional inertia, have made adjustment much slower than it should have been. The financial crisis has also brought out clearly a number of conflicting policy objectives which have to be carefully balanced. In the case of Thailand, the implementation of reform measures has had the following consequences:

The cancellation of energy supply projects by energy importing countries like Thailand, Korea and Japan have had repercussions for energy exporting countries in East Asia such as Indonesia and the Laos PDR, which have worsening economic problems. Thailand’s cancellation of natural gas purchase from Indonesia has made the development of the Natuna gas project improbable. Postponement of 2,700MW out of a 3,000MW power purchase by Thailand from the Laos PDR plunged this country into even more severe economic problems as power sales to Thailand were expected to account for most of its foreign exchange earnings.

Contract renegotiations have to be carefully undertaken so as not to jeopardize investor confidence and the investment climate. Obviously, investors do not like contract renegotiations which do not run in their favor, such as the reduction of prices in the gas supply agreements, or the delay of the commercial operation date of an IPP. Without renegotiations, however, the country and consumers could be left with an unmanageable financial burden.

Deregulation of energy prices is essential. In Thailand, the oil market was deregulated in 1991, thereby creating a more competitive and efficient market which was able to handle the crisis. Despite the weekly rise in the retail price of oil for about 25 consecutive weeks as the exchange rate fell from 25 baht/US$ in June 1997 to 55 baht/US$ in early 1998, consumers were very
tolerant and understanding. However, social and political pressures are much stronger against increases in the price of electricity. Consumers are willing to pay higher prices in line with higher fuel costs but are less willing to pay for the inefficiencies of state-owned electric utilities. This issue is now being intensely debated. The deregulation of the power sector is also being discussed and pressure is clearly pointing in the direction of retail competition and a competitive electricity market.

**The need to amend the various laws** related to the energy sector, and to bring them up to the standards set by international best practice, has become even more apparent. Outdated laws and regulations are making much needed reform slower than it would otherwise be. In the case of Thailand, the enactment of an Electricity Act and the establishment of an independent energy regulatory body is now even more essential in order to complete the process of deregulating the energy sector.
REFORM AFTER THE CRISIS
Privatization and Competition in the British Electricity Industry, with Implications for Developing Countries

Stephen Littlechild*

Stephen Littlechild, who was the regulator of the UK power sector from its privatization until the end of last year, summarizes the British reform experience. This essay evaluates:

- The impact of introducing competition in generation and supply.
- The importance of private ownership.
- The role of the capital markets in improving sector performance.

A longer ESMAP paper from which this essay is drawn also covers the design of the UK wholesale pool, network investment and quality of service, energy efficiency and the environment, and the regulatory process.

Reasons for privatising electricity

Eleven years ago, the White Paper "Privatising Electricity" (February 1988) heralded a fundamental reorganisation of the British electricity industry. By April 1990 the nationalised monopoly structure of the previous forty years was replaced by a quite different structure, with emphasis on private ownership and competitive markets.

Some people, particularly in the rest of Europe, regarded this policy as ambitious or misguided. Some referred to it as an experiment. Yet over time, it has increasingly become apparent that the policy is working well. Many other countries from all over the world have now adopted similar policies, including Norway and Sweden, Australia and New Zealand, Spain and Italy, many parts of the US and Canada, Argentina and Colombia, and many other countries in Latin America. The successful earlier experience of Chile with similar policies has also been influential. There is also increasing interest on the part of developing countries in Asia, Africa and Eastern Europe.

Why did the British Government decide to privatise electricity in 1988? There were several reasons:

- The Government's general preference was to reduce the role of government in industry. Let managers manage, not government.
- The aim was to increase the role of the customer. "Decisions about the supply of electricity should be driven by the needs of customers."
- It was necessary to increase the efficiency of nationalised industries. Although electricity service was generally good, the record on building power stations on time and to budget was not. And the future success of British manufacturing depended on reducing the costs of basic inputs such as energy.
- Privatization was becoming increasingly popular with the electorate, who had proved willing to subscribe for shares and take a personal financial stake in British industry.
- Flotation proceeds were an important source of revenue for the Treasury to spend on more urgent needs or to reduce taxation or government borrowing.

- With the adoption of the RPI-X formula for British Telecom and British Gas, an acceptable method of price regulation had been found. What was previously regarded as unthinkable - the privatization of a monopoly - could now be considered.

The precise reasons for privatization will differ from one industry to another and from one country to another. Investment needs will often be relevant. For example, a reason for privatising the water industry was to access additional private capital to refurbish and improve the infrastructure of pipes and water treatment plants to a greater extent than would have been possible if water remained in the public sector. In telecommunications, an additional aim was to improve speed and quality of service, particularly in the City of London where investment had been inadequate, and to stimulate innovation.

Most of these factors, particularly commercialisation and investment, are likely to be relevant in developing countries, where it is particularly important to transform inefficient loss-making and poor quality industries into efficient and profitable ones. Higher quality services on competitive terms are the basis for improved competitiveness and higher standards of life in the economy as a whole.

Guiding principles

In Britain, the guiding principles were simple:

- Make decisions about the supply of electricity based on the needs of customers.
- Give customers choice by promoting competition where deemed feasible, both among existing players and by allowing new entry.
- Introduce price controls on monopoly, emphasising incentives to increase efficiency.
- Supplement price controls by minimum standards of performance, to protect and enhance quality of supply.

* Stephen Littlechild was the UK Director General of Electricity Supply, 1989-98. He is a Professor of Economics at the University of Birmingham, and now practises as a private consultant.
• Separate as far as possible monopoly activities from competitive ones.
• Establish a regulator to enforce licence obligations on the companies, and to respond to changing conditions and circumstances, guided by statutory duties and processes with well-defined powers.
• Establish consumers' committees to represent the views of customers to companies and the regulator.
• Enable the Government to secure other specified public interest matters such as the extent of non-fossil fuels, financed by a levy on customers.

How has all this worked in practice? The following assessment applies mainly to England and Wales. Similar results may generally be recorded for Scotland, with several achievements but more concerns arising from extensive vertical integration and insufficient competition.

**Competition in generation**

At privatization, important but limited steps were taken to provide for competition in generation. Transmission was separated from generation, and the National Grid Company was created to run the transmission system (275 and 400kV lines), with a duty to facilitate competition in generation and supply. This has been crucial in promoting competition in generation, particularly in assisting new entry. At first, the Company was jointly owned by the 12 regional distribution and supply companies. The separate flotation of the National Grid in 1995 secured its independence from other interested parties.

The rest of the Central Electricity Generating Board (CEGB) was split up into three generating companies: National Power, PowerGen and Nuclear Electric. The two first and largest, often called the duopoly, together initially accounted for nearly 80 per cent of the market in England and Wales. The three companies accounted for nearly 95 per cent of the market. Most of the remainder was supplied by the hitherto-constrained interconnectors with Scotland and France.

Since then, a combination of market incentives and regulatory policy has developed competition. The interconnectors have nearly doubled their market share by increased output and capacity extensions. Nuclear stations, considered too expensive and risky to privatise initially, have increased output by over a half, mainly from more efficient management of maintenance and other outages, and two thirds of the nuclear capacity has now been transferred to private ownership. New entrants bringing new technology and other new ideas to the industry now account for over 15 per cent of the generation market.

The structure of the generation market has thus significantly changed over time, as shown in Table 1. The so-called duopoly now accounts for only half of its original market share, about 40 per cent together or about 20 per cent for each company. The remainder of the output is supplied by over 50 generation licensees, with further projects in the pipeline. Competitive pressures on gas prices, on equipment installation costs and efficiency and on contractual risk-sharing arrangements have brought down the new entry price, and many more projects are seeking to enter the market.

However, competition in generation is still not fully effective. Last year System Marginal Price (SMP) in the Pool was set more than two-thirds of the time by the largest two generators. Increases in SMP in 1997/98 more than offset reductions in the capacity element in the Pool, showing that the two main generators still exercise substantial market power. Pool prices are still at least 10 per cent above the present new entry level based on the latest gas-fired plant. Further divestment is appropriate pending the further entry of new competitors. Both companies have

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This growth of competition has been very welcome, but has not yet sufficed to eliminate the market power of the two largest generators. They were able to increase Pool prices for several years, from an average selling price of 2.3p (3.8c) /kWh in 1990/91 to 3.0p (4.9c) /kWh in 1993/94 (February 1998 prices). Initially this increase reflected an artificially low Pool price, in turn reflecting pre-privatization contractual commitments to purchase and burn coal and contracts securing the majority of generators' revenue, independent of Pool prices. Price was also low initially relative to the expected new entry price at that time. However, the repeated Pool price increases also demonstrated significant market power. Following regulatory action, National Power and PowerGen agreed to divest 6 GW of existing coal-fired plant. This was purchased by Eastern Electricity, and then run more competitively, at higher output than it previously had been. Average Pool price reduced to 2.7p (4.4c) /kWh in 1996/97, as shown in Figure 1.

**Figure 1**


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- System Marginal Price
- Capacity element
- Uplift
- Uplift adjustment

However, competition in generation is still not fully effective. Last year System Marginal Price (SMP) in the Pool was set more than two-thirds of the time by the largest two generators. Increases in SMP in 1997/98 more than offset reductions in the capacity element in the Pool, showing that the two main generators still exercise substantial market power. Pool prices are still at least 10 per cent above the present new entry level based on the latest gas-fired plant. Further divestment is appropriate pending the further entry of new competitors. Both companies have
agreed to do this as part of their strategies of acquiring supply businesses and (in one case) a distribution business.

The position has been exacerbated by the Government's decision to adopt a policy of stricter consents on the building of new gas-fired power stations. Hitherto consents had not been used to restrict new entry. A large number of applicants have now been frustrated. The Government's view is that a number of distortions in the fuel market have disadvantaged coal, and these need to be put right before further gas consents can be given. In my view, this stricter consents policy is now the major obstacle to a more competitive electricity market.

Some questions on competition in generation answered

Is there evidence of efficiency improvements that would not have happened anyway as a result of external factors? Certainly there have been reductions in fuel prices and improvements in technology. But the significantly increased output from existing capacity was independent of this. In addition, staffing levels at the four largest generating companies have fallen by about two thirds. Part of this reduction reflects plant disposals to Eastern Electricity and newer technology but much reflects increased productivity from existing plant. Moreover, the incentives and ability to secure such improvements, to negotiate lower fuel prices and more flexible contracts, and to introduce new technology, would not have existed to anything like the same degree without the pressures of private ownership and competition.

Can developing countries sustain the number and size of generators necessary to achieve effective competition? A more relevant question is whether such countries have scope to increase competition by enabling the entry of independent players. British experience suggests that neither incumbents nor entrants need to be large and diversified. A wholly nuclear company was successfully floated with less than 17 per cent of the market. New entrants have been commercially viable with plants from under 1MW to over 1700MW, typically in single plant companies rather than portfolio generators. Sizes of plants and of companies can be tailored to the circumstances of each country, to achieve both competition and efficiency.

How many competitors are needed for competition? British experience suggests that number of competitors alone is not the main determinant of competition. The decision to split the CEGB into three large companies was driven by the belief that large diversified generation company was necessary in order to incorporate and privatise the nuclear stations; after this was deemed infeasible there was insufficient time to revise the plans so as to create more generators. Subsequent experience has shown that three main companies are not sufficient to secure effective competition, nor indeed is the more diversified structure now obtaining. It is not simply the total number of players that counts, but rather the number with sufficient spare capacity to compete by increasing output: in England and Wales at present only three companies are in that position, since the others, including the entrants with new gas-fired stations, all operate at maximum capacity. More importantly, there is a real likelihood that any fixed number of generators can maintain high prices unless new entrants can come in to challenge them. Hence the crucial need is to remove barriers to entry. Developing countries are particular fortunate that their high potential growth rates are conducive to new entry.

Is the British market biased in favour of base-load plant? It is true that almost all new plant in Britain has so far run base-load, because the structure of prices in the market has made this profitable. However, the relative costs of generation and the need to replace older coal-fired plants for environmental reasons also make this the most economic outcome. In due course some new gas-fired plant will have to run mid-merit as gas takes a greater share of the market, but such plant is already being designed and equipped with flexible fuel contracts to facilitate this. New peaking plants are also being built for peak-lapping.

Competition in supply to industrial customers

The ability of all customers to choose their own electricity supplier was not foreseen in the 1988 White Paper, and many doubted its feasibility or desirability. This was reflected, for example, in the decision not to separate distribution and supply into separate ownership, and in the failure to distinguish clearly in the licences between the duties of distribution businesses and of suppliers. In the event, competition has been warmly welcomed by customers and competitive suppliers.

The Government's desire to protect the coal industry during the latter's own transition to a competitive market led to the introduction of a franchise in electricity supply. The largest 5,000 or so customers, with maximum demand above 1MW, were allowed to choose their own supplier immediately on privatization in 1990. They accounted for about a third of total electricity demand. The next 50,000 customers, with a maximum demand of 100kW to 1MW, were allowed to choose their supplier in 1994. They brought the proportion of the total market open to competition up to about half. The remaining customers, including smaller business and domestic, were scheduled to have access to competition in 1998.

Figure 2 shows that the extent of second tier supply (that is, by suppliers other than the previous local supplier) has steadily increased over time for all sizes of customer. This year, an estimated 80 per cent of the medium-size (above 100kW) market.

Price controls

RPI-X price controls on the monopoly areas of transmission and distribution, coupled with stock market pressures, have protected customers and given companies the incentive to reduce costs, which they have done significantly after some initial variations in the first few years. For example, manpower reductions have been of the order of one third in transmission and one half in distribution. Operating costs net of depreciation were reduced by nearly 40 per cent in transmission from the average of the first three years (1990/1 to 1992/93) to 1997/8, and by about 27 per cent on average for the 12 regional distribution companies from 1992/3 to 1997/8.
In retrospect, the initial price controls and capital structures set by the Government at privatization underestimated the scope for efficiency savings and increased borrowing by companies. However, the process of revising and tightening the controls has ensured that benefits have increasingly gone to customers. The revised controls put in place in 1995 and 1996 have been equivalent in real terms to reductions in distribution charges of nearly 10 per cent a year, every year for the five year duration of the revised controls. Broadly similar reductions apply to transmission charges.

Price controls have also protected customers pending the opening of the supply markets to competition. Initially they allowed the pass-through of generation costs, but now they are firm maximum price restraints on a more focused set of smaller customers. These give clearer protection to customers and stronger incentives to suppliers to reduce their generation purchasing costs.

Price reductions

Competition in generation and supply, tighter price controls in transmission and distribution, and the removal of the nuclear element from the fossil fuel levy following the flotation of British Energy, have brought reduced prices to all groups of customers, ranging from large industrial to domestic. Figure 3 shows that, by the third quarter of 1998, price reductions to industrial customers have been in the range 23 to 33 per cent in real terms, compared to prices at privatization.

Contrary to some concerns, the benefits of competition have not accrued only or mainly to the largest users. Figure 3 shows that the very largest industrial customers have received the lowest reductions, albeit still significant ones. This reflects the relatively advantageous prices that such users were given before privatization. The highest reductions have been for medium-sized industrial customers, who had neither political nor commercial bargaining power under the previous arrangements. Now, prices reflect more closely the relative costs of supply.
The price restraints provided that domestic prices in real terms should fall by an average of 6 per cent in April 1998 and a further 3 per cent in 1999. The reductions varied by company, but ensured that all types of domestic customer would benefit from the move to competition. By mid-1998, domestic customers had received price reductions of about 24 per cent on average relative to prices at privatization.

Since then the opening of the competitive market has offered new opportunities. Further price reductions are on offer from competitors. These vary by area and type of customer, but British Gas, now one of the leading competitors in the electricity market, is offering savings of around 12 per cent on a typical bill. Several competitors are offering additional savings of up to 5 per cent if the customer takes a "dual fuel" offer.

The biggest price reductions offered have been for quarterly credit customers, particularly where they move to direct debit arrangements. In due course incumbent suppliers will have to match these discounts or lose customers. Competitors have not offered significant price reductions to customers with prepayment meters and Economy 7 tariffs (low rates for night-time electricity for storage heaters). This again reflects the levels at which these tariffs were previously set, which were low relative to the costs involved.

Some questions on competition in supply answered

**Does competition in supply matter?** Yes, because without it there would be less incentive on suppliers to purchase all their inputs efficiently, particularly generation, and to seek greater competition in generation. There would also be less incentive to pass these benefits on to customers. Regulation simply cannot replicate all the pressures of the market, and it is unrealistic to expect it to do so. Competition has brought a culture change: companies now have to discover and provide what customers want. For example, industrial consumers have secured better terms and customised metering and billing arrangements. Domestic customers can purchase 'green' electricity if they want to, and leave a company whose service they find expensive or unsatisfactory.

**Does this argument still apply in developing countries?** Yes, because the need to increase efficiency, develop a more commercial approach and meet the needs of customers is arguably even more crucial there. Moreover, independent regulation is less developed, if it exists at all, in such countries, and government control or influence often undermines prudent management. There is correspondingly greater advantage in using competition in the market to protect customers generally and to stimulate efficiency, rather than relying on regulation or government pressure.

**Impact of capital markets**

Some argue that all or most of what is attributed to privatization could be achieved by introducing competition while maintaining government ownership. This overlooks the very significant influence that private ownership has had, coupled with competition in the capital markets that it makes possible. Some examples from Britain are as follows.

- Most of the managers and staff in the industry were initially sceptical or opposed to privatization and competition. Further reflection led them to realise that there would be considerable benefits to them, to the industry and to customers, not least from the freedom to manage their own businesses more effectively and to be remunerated at market rates for doing so. This gradually led them to work actively for early achievement of privatization, with the restructuring and competition that this entailed.

- In order to persuade potentially sceptical customers, voters and investors, it was necessary to reassure them in terms of prices and service obligations for the foreseeable future, and in terms of due process to be followed for modifying these rights and obligations. All parties needed a clear regulatory framework, with adequate but well-defined and limited powers for the regulator and the government.

- Price cap regulation was designed to take advantage of the incentives of private ownership to seek greater efficiency and to innovate. The capital market monitors performance on a continual basis, much more thoroughly and impartially than government did or could, with analysts reporting frequently with comparison between companies.

- Many distribution companies and others considered investing in new gas-fired power stations. The future was uncertain, and the knowledge that their shareholders' own money was at stake was a valuable discipline on the companies. Under government ownership there had been pressure to avoid such investments to protect coal and nuclear interests. There would also have been pressure to put the costs and risks on customers. Private ownership and competition avoided these disadvantages.

- The regional distribution companies were privatised with high levels of equity capital relative to the amount of debt, on the basis that they were risky investments. Subsequent experience, and the pressure of the capital markets, enabled the companies to reduce their cost of capital by significantly increasing the proportion of debt.

- Under government ownership, pricing policies and investment plans had been vulnerable to economic fluctuations and short-term policy pressures to deal with inflation, unemployment and other macroeconomic issues. Since privatization, companies' pricing and network investment policies have been governed by their licence obligations which are set for the longer term, independent of such macroeconomic pressures. Neither network nor generation investment has been restricted by financial considerations beyond those applicable to the private sector generally.

- Private ownership has exposed the companies to the threat of takeover. This threat is real: almost all of the regional compa-
nies are now under different ownership than at the time of privatization, and some have changed hands more than once. This means that new management can be introduced when the existing management fails to perform as effectively as another potential owner thinks it should. To do this, the new owner must be prepared to back its claims with its own money. It is thus subject itself to the discipline of the market.

• The possibility of takeover facilitates the restructuring of the industry to achieve greater efficiency. Mergers can achieve potential economies of scale or scope, demergers can enable managements of different businesses to concentrate on what they are best at. Government does not need to plan the structure of the industry: its role can be limited to evaluating the potential effect of such changes on competition and on regulatory effectiveness.

In developing countries capital markets are not so extensive. But it is still feasible and desirable to shift from pledging government credit to raising private capital. All the above comments still apply, based on the incentives provided by private ownership: a liquid capital market simply enhances these incentives. Indeed, some of the arguments for private ownership -- such as the need to access capital to meet growing demand and improve quality of service -- are even stronger. And the discipline provided by private ownership is even more needed in countries where this has been absent for so long.

Conclusions

There is more to be done in Britain, for example in terms of promoting competition and revising the price controls. And more could be said about the beneficial effects of privatization and competition in other respects, for example on quality of supply and the environment. These issues are discussed in the longer paper referred to earlier. Nonetheless, some preliminary conclusions can be drawn already.

The principles of private ownership and competitive markets have worked well. The British electricity industry is now more efficient and innovative, and its management and workforce deserve great credit. All groups of customers have benefited significantly in terms of price and quality of service. The costs of introducing competition have already been outweighed by the benefits, and more benefits are to come. The companies, the regulator and the Government all need to take appropriate further action in order to maintain and extend these successes in future. But the policy has undoubtedly been the right one, for customers and for the country generally.

In some respects the circumstances of each developing country are different from Britain and from each other. But essentially the same principles of public policy apply, and the commonly expressed concerns and objections discussed above do not invalidate these principles. With appropriate modifications for the circumstances of each case, privatization and competition seems the right policy for developing countries too.
Commentary
The British Reform Experience: a Developing Country Perspective
Manuel Dussan*

This commentary on Stephen Littlechild’s essay on the British reform experience discusses the application to developing country power sectors of its arguments regarding the impact of wholesale competition, retail competition, private ownership, and the capital markets on sector performance.

Competition in generation
Professor Littlechild’s summary of the difficulties faced in introducing competition in generation illustrates very well the importance of market structure (degree of vertical and horizontal separation). Developing countries have typically taken one of three different paths to introduce competition in generation.

- Some countries, for example Chile, Argentina, Colombia, Bolivia, Peru, Brazil, El Salvador and Ukraine, have adopted the essential elements of the British model (unbundling, wholesale price deregulation, and a competitive pool), albeit with significant modifications.
- Other countries, for example Hungary, Poland, Georgia, Armenia, and Panama, have implemented extensive unbundling, but have established a wholesale market based on a single-buyer scheme, with limited options for direct contracts between generators and consumers.
- Still other countries, mainly in East Asia and characterized by high rates of demand growth, introduced competition for the development of new generation projects by IPPs, under PPAs with existing state-owned monopolies. Examples of countries that have taken this approach are Malaysia, Thailand, the Philippines, Indonesia, and China.

Competitive power pools
Most of the developing country experience with competitive power pools has to date been in Latin America and the Caribbean. In general, it has been positive, and supports Professor Littlechild’s argument that developing countries can use competition and the deregulation of wholesale prices as effective instruments to improve efficiency and, at the same time, attract private financing for needed investments.

- Operational efficiency. Generators in Chile and Argentina have increased operational efficiency. In between 1992 and 1997, the average spot price in Argentina decreased from about US$ 42 to about US$ 25 per MWh; thermal availability increased from 48% to 75%; and distribution losses were reduced from 21% to less than 12%.
- Number and diversity of competitors. More than 50 generators participated in the wholesale market in Argentina, and 29 in Colombia, with installed capacities ranging from 20MW to 2,500MW. New entrants have tended to install relatively small gas turbines, but a wide spectrum of fuels have been used, from thermal to hydro.
- Facilitating competition. The removal of barriers of entry in Argentina, Colombia and Chile has been crucial to the development of gas-fired plants by new entrants to challenge incumbent generators. The availability of natural gas in the region has made competition feasible even in relatively small power systems. In particular, the development of gas pipelines from Argentina to Chile opened new supply options and stimulated competition in the electricity market in Chile.
- Market power. All the reforming countries of Latin America and the Caribbean (except Chile), and especially Argentina, Colombia and Brazil, put in place at the beginning of the reform process a market structure amenable to competition by vertical separation of generation, transmission and distribution, and substantial horizontal separation of generation and distribution. All countries, except Colombia, introduced centralized dispatch based on audited production costs, rather than on price bids (though Argentina has now switched). All of them allowed distributors and large consumers to enter into direct power purchase contracts with generators. Nevertheless, market power has been a problem. For example, a dominant generator/transmission company in Chile has curbed competition and gave rise to anti-trust complaints related to network access, and bottlenecks in the transmission network in Colombia have given constrained-on generators the opportunity to increase pool prices.
- Financing investments. Private financing of generation expansion to meet demand has typically not been a problem. More than 4,500MW (about 28% of total installed capacity) have been installed in Argentina since the sector was reformed, and about 4,000MW more are planned for year 2000. Installed generation capacity in Colombia has increased by more than 3,000MW (about 20% of total installed capacity), in the four years since reform started. The high volatility of prices in the spot market in Colombia, typical of hydro-based generation systems, has raised some concerns over whether the remuneration to generators in the spot market will provide sufficient revenue to cover the cost of capital investments, but has not deterred the privatization of a substantial portion of generation assets and the development of some private merchant plants. In 1997, a capacity charge was introduced into the power pool as a mechanism to smooth the revenue stream for sales in the spot market. More than 4,000MW of hydroelectric plant with limited long-term contracts were privatized. A 160MW private merchant plant was completed soon afterwards.
- Public ownership and the pool. The experiences of Ukraine and Colombia illustrate the problems of introducing a spot market which incorporates state-owned enterprises that are in poor financial shape. The establishment of a power pool in Ukraine,

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in a sector with low cash collections, extensive barter transactions and poor payment discipline did not help to improve efficiency, but gave the Government substantial control over the wholesale power market. It raised the issue of whether a decentralized pool based on bilateral contracts and a market for the balance would have been a better option. In Colombia, several inefficient state-owned distribution companies with a poor credit record could not get long-term contracts to hedge the risk of volatile spot prices and had to rely on the spot market as the only source of supply. Nonpayment by these companies jeopardized the operation of the spot market.

The single-buyer model

A variety of developing countries have unbundled generation, transmission and distribution, but have adopted a single-buyer (SB) model to manage wholesale electricity trade.

- **Poland**, with a installed capacity of 33,000MW, opted for a SB model as an initial step in a gradual process to the development of a spot market. The transmission company, responsible for SB functions, enters into initial PPAs with generators at prices set to ensure the financing of needed expansion and rehabilitation investments, and to bring bulk tariffs into line with the retail tariff adjustment program approved by the Government.

- **Hungary** privatized most of generation and distribution under a SB scheme with regulated wholesale prices to provide a guaranteed rate of return to the recently privatized generators. It is now considering how to implement third party access to meet the requirements of the European Union regarding the internal electricity market.

- **Countries with a relatively small installed generation capacity** and few generation plants (for example Armenia – 3,600MW; Georgia – 4,600MW; Panama – 1,000MW) have concluded that generation cannot usefully be deregulated during an initial period, and should remain under contract to a regulated SB. However, distribution companies and large consumers have access to direct purchases from generators in a restricted parallel market.

The "East Asian" model

The IPP-based model is evaluated in more detail elsewhere in this report (see the survey essay by Yves Alibouy, and the essays by Michael Klein, John Besant-Jones, and Piyasvasti Amranand in this chapter). It should be considered separately from the SB model, since the unbundling of the electricity sector typically undertaken by countries that have opted for the SB model is missing. The SB model has usually been a conscious transitory arrangement in the process of implementing a competitive market: unbundling is done to facilitate the introduction of competition in the market later on. One serious concern with this approach is that there are losses in economies of scale, scope and coordination related to unbundling, which may not be counterbalanced by the benefits of competition, if the transition to a competitive market takes too long.

Consumer choice and price deregulation for large customers have been a key element to stimulate efficiency in wholesale markets in Latin America and the Caribbean. Distribution companies with captive markets, which are allowed the pass-through of generation costs, are not effective instruments for the promotion of competition in generation.

- In Chile, the market for customers over 2MW was open to competition, and the market price was used as a reference that controls the discretion of the regulator in setting bulk tariffs for supply to captive customers. As a result, large and sophisticated industrial consumers have stimulated intense competition in the northern system.

- **Argentina** started with a cut-off of 1MW, which was reduced to 100 kW in 1995. In 1997 there were more than 1,100 large and medium-sized consumers participating in the wholesale market which could enter into long term contracts with the generator of their choice or purchase power in the spot market.

- **Colombia** started with a cut-off of 2MW in 1993. This cut-off was later reduced to 500 kW, and a further reduction to 100 kW will be effective by the end of 1999. Price deregulation for large customers and unbundling has made pricing more transparent and made cross-subsidization more difficult.

The experience in Latin America and the Caribbean shows that the larger the base of customers with choice to select supplier the better for the competitive market. How far to go will depend on whether extending customer choice to domestic consumers is feasible from the technical and economic point of view. In countries with a low level of electricity consumption per household it may not be justifiable to go too far. But even under SB schemes, allowing large consumers to select their supplier or to develop their own generation will be beneficial because of the resulting competitive pressure on the SB and the distribution companies; it could also simplify price regulation. In many countries in the FSU, where a substantial portion of large consumers are not creditworthy and there are substantial problems with nonpayments, direct contracts between generators and large customers are being used as instruments to restore financial discipline and to provide reliable service to industries that can pay.

Privatization

Chile is often cited as demonstrating the priority of regulatory reform over privatization. Nevertheless, it is also recognized that the privatization of existing publicly-owned distribution companies, not subject to competition or to changes in the regulatory regime, resulted in efficiency improvements. However, Chile may not be a typical case, because the publicly-owned utilities in Chile were better run than most prior to the reform.

Colombia and Ukraine are good examples of countries that first introduced a competitive market and regulatory reform, and have then taken a gradual approach to the introduction of private ownership. In both cases, Professor Littlechild’s insistence that private ownership is essential if the benefits of a competitive market are to be captured is borne out.

Ukraine

From 1994 to 1996, the Ukrainian electricity sector was restructured based on a model similar to the British one: unbundling and corporatization of generation and distribution, creation of a spot market, deregulation of wholesale prices, open access to the transmission network, creation of an independent regulatory commission, and creation of an independent market administra-
tor. Privatization of generation and distribution companies, however, was to be implemented in a second stage. Average retail electricity prices tripled in US$ terms to reach US$ 39 perMWh – close to marginal costs. Strict macroeconomic stabilization measures during the same period, cash-strapped consumers, and the barterization of the economy, led to substantial increases in payment arrears. As a result, the wholesale power market started operations in 1996 in a severe crisis characterized by:

- nonpayment of electricity bills and low cash collections (suppliers of the regulated market collected on average 70% to 80% of electricity bills, of which about 20% was in cash
- lack of working capital
- substantial tariff distortions (one third of residential consumers had privileged tariffs with large discounts)
- substantial barter transactions (50% of total collections)

By late 1996 the market administrator owed US$ 1.3 billion to generators, and suppliers owed US$ 1.1 billion for electricity purchases in the market.

In addition, a range of political interference, from the enforced service of delinquent but preferred customers to direct manipulation of spot prices for wholesale transactions prevented the market from effectively improving financial discipline and productive efficiency.

The implementation of the privatization program has also been complicated. There was disagreement between the Government and Parliament about the method and objectives of privatization. Parliament was quite reluctant to give up ownership control of power utilities. In 1997, the Government failed to sell to financial investors minority stakes in the generation and distribution companies. Only a small portion was sold to workers and managers. In 1998, the Government offered again minority stakes with management control. Local financial investors took control of 7 distribution companies. Financial discipline has not improved.

**Colombia**

During an initial stage from 1994 to 1996, regulatory reform was implemented and a wholesale market was established. Private participation was limited to IPPs with PPAs guaranteed by the Government. Average retail prices were adjusted to reflect costs. The state-owned enterprises signed performance contracts with Government institutions. Nonetheless, poor financial performance and nonpayment for purchases in the spot market by a number of small and medium state-owned distribution companies threatened the sustainability of the spot market.

Privatization of a substantial portion of generation and distribution assets from 1996 to 1998 and private participation in new generation plants improved financial discipline in the spot market and the governance of the wholesale market significantly. Private participation has also put substantial competitive pressure on existing state-owned enterprises. Most of the remaining state-owned distribution and generation companies are being privatized, except for a few municipal companies, some of them well-run and able to compete and improve efficiency.

**Impact of capital markets**

Private participation in the electricity sector in developing countries has grown substantially during the 1990s, based mainly on the divestiture of state-owned enterprises and the development of greenfield projects by IPPs.

The effectiveness of competition for capital in the financial markets at improving efficiency in the power sector is necessarily conditioned by the scheme adopted for private participation.

- **Mass privatization.** This method was preferred in Russia and the Czech Republic, for example, but has failed, in general, to achieve improvements in efficiency or quality of service.
- **Private participation in IPPs.** Since the majority of greenfield projects have been developed under long-term take-or-pay contracts guaranteed by governments, they have introduced greater accountability and efficient technologies into the sector, but they have mostly transferred market risks to governments, which substantially negates the benefits that the discipline of capital markets might have on investment decisions. The exceptions have been in Latin America and the Caribbean, where about 50% of the projects were merchant power plants operating in a competitive power pool. Local capital markets played a limited role in financing large projects, except in the case of Malaysia.

- **Sale of majority stakes in publicly-owned power utilities to foreign strategic investors,** and of smaller shares to workers and managers has contributed to substantial efficiency improvements in both Latin America and Eastern Europe. Privatization of generation and distribution companies in Chile during the late 1980s was based on direct sales to workers and share offerings in the stock market, and more than 60% of shares are now under the control of workers and local institutional investors (pension funds).

Domestic capital markets are too underdeveloped in most developing countries to provide a market assessment of performance by private utilities and regulators. However, the discipline of capital markets in the countries of origin of the investors, coupled with competition, provides sure incentives to improve efficiency.
A Scorecard for Energy Sector Reform in Developing Countries

Robert Bacon*

This essay presents the results of a comprehensive study of how far energy sector reform has gone in developing countries. Focusing on six central steps, the study finds that:

- Energy sector reform has a long way to go: in all sectors except upstream oil and gas, developing countries have taken on average only one third of possible reform steps.
- Developing countries with private participation in their energy sector are still rare, and especially so in Africa and in the Middle East.
- Variations between countries in the number of reform steps taken is large.

A few developing countries have succeeded with comprehensive reform: but in the great majority, little or nothing has yet been done to install energy market fundamentals.

Note: this essay uses the World Bank’s regional acronyms, which are explained in the glossary.

Measuring energy sector reform

Although many countries have discussed energy sector reform, and there are by now detailed plans for reform in several of these countries, it is less clear at a global level what steps have actually been taken. The primary aim of this survey is to give the broadest possible overview of the extent to which the energy sector reform agenda has been adopted in developing countries. The focus is the number of countries that have taken various reform steps, rather than on a measure of reform within each country (such as the percentage of assets sold) or one which treats countries differently according to their size.

The scorecard was compiled by administering a simple questionnaire to World Bank staff with experience of the energy sector in the countries covered. The questionnaire on which it is based covered the power, upstream oil and gas, downstream oil, and downstream gas sub-sectors, and gives a picture of the state of affairs in the middle of 1998. For each sub-sector, the scorecard covered all those countries in which the sub-sector exists, and has not been entirely in private ownership for the last 10 years – so that it captures the progress under the current reform movement. The scorecard monitors six important steps in energy sector reform: four of which make possible the introduction of private sector capital into a sector which had previously been entirely state-owned, and two of which actually constitute private involvement. The six steps are described in Box 1.

Box 1
Six central steps in energy sector reform

1. Corporatization and commercialization of the state-owned enterprise (SOE).
The removal of the SOE from direct government control, and its establishment as an independent legal corporation with the goal of behaving like a commercial company (by aiming to maximize profits, for example) is seen as the first step in a reform process. This step makes it more likely that costs can be reduced, efficiency improved, and tariffs raised to cover costs (if they need to be), so that the company would be more attractive to potential purchasers. Without this step private sector companies would not be able to compete with the SOE on equal terms, and hence would demand favorable conditions at a cost to the taxpayer before they enter the market.

2. Passage by Parliament of an Energy Law which permits the unbundling and/or privatization of the sector in part or in whole.
This step is crucial to allowing the sale of a state utility to the private sector. Since most countries have also considered selling elements of the utility separately, in order to heighten competition while retaining natural monopoly elements, such as transmission, in public ownership, the law also needs to establish these elements as entities. The questionnaire specifically asks whether the law is completely passed, since in many the delay between drafting the new law and enacting it has been persistent. Only once the law has been passed can it be effective and have any impact on the performance of the sector, through encouraging the entry of new investments and ownership.

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3. Establishment of a regulatory body that is separate from the SOE and from the Ministry.

Regulation is not necessary for the control of that private sector investment in greenfield sites which is bound by contract and the general legal framework. However, regulation is extremely important if any of the existing assets are sold off, particularly where the sector has been unbundled. Pricing and quality of service need to be regulated wherever the sector is not fully competitive. Again the scorecard monitors those countries in which an independent regulatory body is actually functioning.

4. Restructuring or separation of the SOE.

This step follows corporatization, and makes it easier to privatize by separating those parts of the utility which are most suitable for private ownership.

5. Private sector investment in greenfield sites, which are either in operation or under construction.

The entry of the private sector into the ownership of new investment has been seen as a crucial first step in the reform of the whole sub-sector. A country which is willing to contemplate some private sector participation, even though it does not address directly the inefficiencies of the existing industry, may be more open to consideration of extensive reform and the state-owned company may be encouraged to improve its own operations, partly by the example set by the private sector operator. Countries where construction has not begun, even if there is a Memorandum of Understanding or a contract, are counted as not having such investment in the scorecard.

6. Privatization of at least some of the existing SOE.

This step represents the core of reform. A country which has allowed some privatization of existing assets has clearly put in place all the steps required for as much private sector ownership as the sector requires, and from which the sector could benefit. The questionnaire asks whether there is some privatization, not whether the sector has been completely privatized. Hence the scorecard measures whether the country has proved willing to permit private ownership, rather than the extent of private ownership. For the power sector the questionnaire separates generation and distribution, since the latter has proved more problematic, and has no equivalent to the greenfield private investment provided by IPPs in generation.

The questionnaire for the downstream oil sector was slightly different because it separated refining from the wholesale and retail functions. For both, the questionnaire asked about corporatization/commercialization and about privatization of previously state-owned assets. For refining it asked about private sector greenfield investment, but for the retail and wholesale element it asked whether prices are freely set, since virtually all countries have some private sector retail gasoline outlets.

There is a natural sequence to these steps if the country is gradually moving towards full private sector involvement, and so the number of countries having taken each step is not yet likely to be equal. There is an expectation that some steps should be taken before others: the state company should first be corporatized and commercialized; next, a law permitting the entry of the private sector should be passed; then a regulator established; following this the state enterprise should be restructured, by vertical and horizontal separation; after this greenfield investment could be allowed; and finally existing assets should be divested. Although such a sequence is not essential, it has a strong logic so that the step expected to be most common would be the corporatization and commercialization of the SOE, and the final least common step would be the divestiture of existing assets.

For each of the steps that has been taken in the relevant sub-sectors, one point is accrued, giving a maximum of six for a sub-sector when all the steps have been taken. The number of steps actually taken, expressed as a percentage of this maximum, constitutes the "reform indicator". The reform indicator is calculated for each sub-sector; on a country-by-country basis; for the aggregate of all countries in the sample; and for regional groupings of countries.

These figures understate what actually remains to be done to achieve the maximum benefits from the introduction of the private sector for several reasons:

- the survey asked whether there were any private sector participation, so that even a small asset or share sale would be counted as "yes" and given equal weight to complete divestiture. All those countries with partial privatization still have more to be accomplished;
- all countries are treated as equally important in the questionnaire, so that having some degree of privatization receives the same weight in different countries irrespective of the size of the sector;
- with certain countries organized regionally, a success in one region (e.g. in one state of India) counts as a success for the whole country, whereas in reality the other states may be very far from reform.

How many reform steps have been taken?

The results are given separately for each sub-sector, since the coverage is rather different between them (the number of countries in the sample which both have the sub-sector and where it has not been entirely in private sector ownership for the last 10 years, is indicated in the table). Table 1 gives the percentage of countries that have taken each step in each of the sub-sectors, as well as the overall reform indicator for the sub-sector.

The reform indicator for all sub-sectors is around one third, except for upstream oil and gas where it reaches 50%. These simple figures are a firm indication that, at a global level, the energy sector is still a long way from realizing the fullest gains from the involvement of private sector capital. The much higher level of reform steps taken in upstream oil and gas is significant, since this is a sub-sector where there has often been fierce Government opposition to the entry of the private sector. The distinguishing feature of the upstream is that the cost of exploration and development, especially of off-shore oil, can be very large, and the risks also very great, that the state cannot afford the financing burden. In such a case, private finance has been recognized to be essential, and it has been allowed into the sub-sector through the use of concessions. This has required the law to be changed and often the SOE to be restructured, but in very few
Table 1
Percentage of developing countries that have taken reform steps (no. of countries in sample)

(a) Power (115)

<table>
<thead>
<tr>
<th>Corporatization / Commercialization</th>
<th>Law</th>
<th>Regulator</th>
<th>Private greenfield investment</th>
<th>Restructuring</th>
<th>Privatization of existing assets</th>
<th>Reform indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>44%</td>
<td>33%</td>
<td>29%</td>
<td>40%</td>
<td>33%</td>
<td>25%</td>
<td>34%</td>
</tr>
</tbody>
</table>

(b) Upstream oil and gas (49)

<table>
<thead>
<tr>
<th>Corporatization / Commercialization</th>
<th>Law</th>
<th>Regulator</th>
<th>Private greenfield investment</th>
<th>Restructuring</th>
<th>Privatization of existing assets</th>
<th>Reform indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>67%</td>
<td>69%</td>
<td>31%</td>
<td>69%</td>
<td>43%</td>
<td>14%</td>
<td>49%</td>
</tr>
</tbody>
</table>

(c) Downstream gas (55)

<table>
<thead>
<tr>
<th>Corporatization / Commercialization</th>
<th>Law</th>
<th>Regulator</th>
<th>Private greenfield investment</th>
<th>Restructuring</th>
<th>Privatization of existing assets</th>
<th>Reform indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>60%</td>
<td>40%</td>
<td>40%</td>
<td>27%</td>
<td>85%</td>
<td>27%</td>
<td>98%</td>
</tr>
</tbody>
</table>

(d) Downstream oil: refining (57)

<table>
<thead>
<tr>
<th>Corporatization / Commercialization</th>
<th>Private greenfield investment</th>
<th>Privatization of existing assets</th>
<th>Reform indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>54%</td>
<td>23%</td>
<td>26%</td>
<td>35%</td>
</tr>
</tbody>
</table>

(e) Downstream oil: wholesale and retail (72)

<table>
<thead>
<tr>
<th>Corporatization / Commercialization</th>
<th>Privatization of existing assets</th>
<th>Free retail prices</th>
<th>Reform indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>43%</td>
<td>28%</td>
<td>35%</td>
<td>32%</td>
</tr>
</tbody>
</table>

cases has the country been willing to privatize existing upstream oil and gas assets.

As for the sequencing of reform, Table 1 confirms that corporatization and commercialization is indeed the commonest step, and the privatization of state-owned assets the least common one. A notable feature is that in power and upstream oil the percentage of countries permitting the entry of private investors into greenfield sites is much larger than the number that have introduced formal regulation, or that have restructured the industry. Such countries appear not to be preparing for privatization and the construction of competitive markets so much as to be augmenting the existing system by admitting private investment on new sites, probably selling to the SOE through some form of contract. The low proportion of countries that have privatized existing assets confirms this interpretation, especially for upstream oil and gas.

Is the degree of reform uniform across countries?

The aggregate table shows that a great deal of reform has still to be carried out, especially those steps that have the potential to bring the greatest benefits to the country: private sector investment in greenfield sites, and the privatization of existing assets. In assessing the status of reform in a global context, it is important also to see whether the extent of reform is fairly uniform across countries, or whether there are very different take-up rates.

The scorecard found that the reform progress is spread very unevenly between countries, with upstream oil and gas experiencing the most even pattern. In the power sector more than one third of the countries in the sample of 115 had taken none of the six steps and one half had taken only one step – the 10% most reforming countries accounted for 30% of all the reform steps that had been taken. This pattern suggests that reform is not a uniform process, but rather that it proceeds rapidly when conditions are favorable, and does not even start when conditions are unfavorable.

Regional patterns of reform

Table 2 shows the percentages of the countries in each region which have taken each step, and the reform indicator for each region.
Table 2(a) shows very clearly that reform in power is much more advanced in LAC than in other parts of the world. In LAC 71% of the key steps have been taken, while for AFR the indicator is just 15%, and for MNA it is 17%. Looking at the individual steps it can be seen that even in LAC only 40% of countries have started to privatize existing generation or distribution, while in AFR this figure is extremely low at 4%.

The regional picture for upstream oil and gas is very different from that of power. In all regions the overall indicator is around 50%, and in AFR it is nearly 60%. In those African countries where there is production there has been an almost universal willingness to allow private concessions, which is also associated with the need for the state oil company to be corporatized and commercialized and a law to be passed, but only one country has been willing to privatize existing assets.

In downstream gas the LAC region again has seen considerable activity, with all steps being taken equally often, including privatization. Other regions have done little for private investment on greenfield sites, and almost nothing for divestiture.

The reform effort in refining is notably low in AFR, MNA and LAC. The latter indicates that in LAC there has been a different attitude to privatization of refining than to the privatization of power, upstream oil and gas, and downstream gas. In ECA, where a large number of countries have domestic refining, a high proportion have experienced privatization, suggesting a different view of the sector.

### Table 2
Percentage of developing countries in each region that have taken reform steps (no. of countries in region)

#### (a) Power

<table>
<thead>
<tr>
<th>Region (no. of countries)</th>
<th>AFR (48)</th>
<th>EAP (9)</th>
<th>ECA (27)</th>
<th>LAC (18)</th>
<th>MNA (8)</th>
<th>SAR (5)</th>
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<tbody>
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<td>Corporatization/Commercialization</td>
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<td>44</td>
<td>63</td>
<td>61</td>
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<td>40</td>
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<td>Law</td>
<td>15</td>
<td>33</td>
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<td>Regulator</td>
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<td>41</td>
<td>83</td>
<td>0</td>
<td>40</td>
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<td>IPPs</td>
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<td>33</td>
<td>83</td>
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<td>Restructuring</td>
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<td>52</td>
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<td>40</td>
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<td>Generation Privatization</td>
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<td>40</td>
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<tr>
<td>Distribution Privatization</td>
<td>4</td>
<td>11</td>
<td>30</td>
<td>44</td>
<td>13</td>
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<td>15</td>
<td>41</td>
<td>45</td>
<td>71</td>
<td>17</td>
<td>50</td>
</tr>
</tbody>
</table>

#### (b) Upstream oil/gas

<table>
<thead>
<tr>
<th>Region (no. of countries)</th>
<th>AFR (11)</th>
<th>EAP (5)</th>
<th>ECA (17)</th>
<th>LAC (8)</th>
<th>MNA (5)</th>
<th>SAR (3)</th>
</tr>
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<tbody>
<tr>
<td>Corporatization/Commercialization</td>
<td>73</td>
<td>80</td>
<td>65</td>
<td>63</td>
<td>80</td>
<td>33</td>
</tr>
<tr>
<td>Law</td>
<td>91</td>
<td>60</td>
<td>65</td>
<td>63</td>
<td>60</td>
<td>67</td>
</tr>
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<td>Regulator</td>
<td>36</td>
<td>40</td>
<td>24</td>
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<td>40</td>
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<td>Concessions</td>
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<td>63</td>
<td>80</td>
<td>67</td>
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<td>18</td>
<td>38</td>
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<td>47</td>
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#### (c) Downstream gas

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<th>LAC (9)</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Corporatization/Commercialization</td>
<td>33</td>
<td>100</td>
<td>59</td>
<td>56</td>
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<td>25</td>
<td>41</td>
<td>78</td>
<td>0</td>
<td>33</td>
</tr>
<tr>
<td>Restructuring</td>
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<td>25</td>
<td>30</td>
<td>56</td>
<td>17</td>
<td>67</td>
</tr>
<tr>
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<td>Privatization</td>
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<td>0</td>
<td>33</td>
<td>56</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reform Indicator</td>
<td>31</td>
<td>38</td>
<td>36</td>
<td>63</td>
<td>11</td>
<td>50</td>
</tr>
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</table>

#### (d) Downstream oil: refining

<table>
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<th>EAP (4)</th>
<th>ECA (22)</th>
<th>LAC (11)</th>
<th>MNA (6)</th>
<th>SAR (3)</th>
</tr>
</thead>
<tbody>
<tr>
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<td>55</td>
<td>75</td>
<td>59</td>
<td>45</td>
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<td>Investment</td>
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<tr>
<td>Privatization</td>
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<td>50</td>
<td>45</td>
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<tr>
<td>Reform Indicator</td>
<td>24</td>
<td>58</td>
<td>45</td>
<td>24</td>
<td>17</td>
<td>44</td>
</tr>
</tbody>
</table>

#### (e) Downstream oil: wholesale and retail

<table>
<thead>
<tr>
<th>Region (no. of countries)</th>
<th>AFR (17)</th>
<th>EAP (8)</th>
<th>ECA (26)</th>
<th>LAC (11)</th>
<th>MNA (5)</th>
<th>SAR (5)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Corporatization/Commercialization</td>
<td>29</td>
<td>50</td>
<td>50</td>
<td>36</td>
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<td>60</td>
</tr>
<tr>
<td>Privatization</td>
<td>24</td>
<td>0</td>
<td>42</td>
<td>18</td>
<td>40</td>
<td>20</td>
</tr>
<tr>
<td>Free prices</td>
<td>6</td>
<td>13</td>
<td>42</td>
<td>45</td>
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<tr>
<td>Reform Indicator</td>
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<td>21</td>
<td>45</td>
<td>33</td>
<td>27</td>
<td>27</td>
</tr>
</tbody>
</table>
The downstream retail oil market is very different from the other sectors. As well as existing in every country, in some 37% of countries the sector had had private sector participation for at least ten years. Table 2(e) shows that, for those countries where this had not been the case, the willingness to privatize was generally low, notably in LAC and EAP. Again the ECA region had a substantial number of countries which privatized the retail/wholesale functions. It appears that in some regions the downstream oil sector has been seen as “strategic” sector which the government has been unwilling to sell, while in ECA governments have been willing to divest themselves of this underperforming sector. This contrast with the pattern in the upstream oil and gas sector where LAC has the highest proportion of privatization, and all other regions have virtually no privatization.

Has private greenfield investment led to other reform steps?

One strategy advocated for the power sub-sector in the early days of the reform movement was to encourage the entry of IPPs, on the grounds that this might be less problematical for the government since it did not involve the sale of national assets, or the immediate redundancies which a private sector owner might require. It was hoped that IPPs would both set an example of good performance to the rest of the sector, and also eventually force the sector to become more efficient and to be willing to embrace privatization of existing assets. If this were to happen the sector would ideally need a law and a regulator, even though IPPs, when governed by long term take-or-pay contracts, do not require either for their successful operation. This argument applies equally to all the sub-sectors with respect to the entry of the private sector into “greenfield” investment.

As a test of whether governments, that were willing to admit the private sector into investment in new projects, were willing also to undertake the other reform steps, the relationship between these stages of reform are calculated. Table 3 shows what proportion of this subset have undertaken the other reform steps, relative to the proportion of all countries that have taken these steps. For example, 43 countries have IPPs and of these 26 (57%) have passed a privatization law, while 38 countries (33%) of the whole survey of 115 countries had passed a law.

In the power, downstream gas, and refining sub-sectors the presence of private sector investment on a greenfield site is associated with a higher proportion having taken other reform steps, including privatization of existing assets. The difference in proportions between those with private sector investment and all countries is around 20% for power, and is around 30% for downstream gas and refining. In these sectors countries which have admitted IPPs etc. have been substantially more ready to take other reform steps. In upstream oil and gas the picture is quite different. The presence of a concession is associated with only a slight increase in the proportion having taken other reform steps, and with virtually no increase in the proportion that have privatized existing assets.

Reform in the energy sector as a whole

Although each of the sub-sectors has responses from different numbers of countries, an aggregate picture can be obtained by pooling the reform indicator scores globally and by region. Adding the average values together gives a variable whose maximum value is 24. Table 4 gathers the results from the individual regions and sub-sectors, as well as the global figure, and then aggregates these to obtain the “overall” reform indicator expressed as a percentage of the maximum possible.

The overall reform indicator for all countries and all sectors is 39%, indicating that globally substantially less than half the key steps for energy sector reform have yet been taken. The table also confirms that, taking all the key reform steps in all sectors, there is great variation between regions: the best that has been achieved is 53% of the maximum in LAC, while the large group of African countries have taken only one third of the steps and the countries in the MNA region have taken only one quarter of the total number of key steps.

The steps of corporatization/commercialization, law reform, regulation, and separation are all necessary to the reform process, in that they make possible the two key steps that involve the actual entry of the private sector, but they do not by themselves bring about the improvements sought. Table 5 concentrates on the steps which directly involve the participation of the private sector, either in new investment or in the privatization of the existing assets. Taking a weighted average rate across the sub-sectors gives the average propensity to allow private sector investment in new sites, and the average propensity to allow private sector involvement in the ownership of existing assets.

Table 3
Percentage of developing countries with private greenfield investment that have taken other reform steps

<table>
<thead>
<tr>
<th></th>
<th>Corporatization / Commercialization</th>
<th>Law</th>
<th>Regulator</th>
<th>Restructuring</th>
<th>Privatization</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Power:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With IPPs</td>
<td>63</td>
<td>57</td>
<td>50</td>
<td>57</td>
<td>50</td>
</tr>
<tr>
<td>All</td>
<td>44</td>
<td>33</td>
<td>29</td>
<td>35</td>
<td>25</td>
</tr>
<tr>
<td><strong>Upstream oil &amp; gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With concessions</td>
<td>74</td>
<td>79</td>
<td>38</td>
<td>50</td>
<td>18</td>
</tr>
<tr>
<td>All</td>
<td>67</td>
<td>69</td>
<td>31</td>
<td>43</td>
<td>14</td>
</tr>
<tr>
<td><strong>Downstream gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With private investment</td>
<td></td>
<td>80</td>
<td>67</td>
<td>67</td>
<td>60</td>
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<tr>
<td>All</td>
<td>60</td>
<td>40</td>
<td>40</td>
<td>35</td>
<td>27</td>
</tr>
<tr>
<td><strong>Refining</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With private investment</td>
<td></td>
<td>92</td>
<td>n/a</td>
<td>n/a</td>
<td>62</td>
</tr>
<tr>
<td>All</td>
<td>54</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>28</td>
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</tbody>
</table>
### Table 4
Energy sector reform indicators by region

<table>
<thead>
<tr>
<th></th>
<th>Power</th>
<th>Upstream oil/gas</th>
<th>Downstream gas</th>
<th>Downstream oil refining</th>
<th>Downstream oil wholesaler &amp; retail</th>
<th>Total reform indicator</th>
<th>Percentage of maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Global</strong></td>
<td>2.06</td>
<td>2.94</td>
<td>2.29</td>
<td>1.05</td>
<td>0.96</td>
<td>9.30</td>
<td>39%</td>
</tr>
<tr>
<td><strong>AFR</strong></td>
<td>0.88</td>
<td>3.55</td>
<td>1.83</td>
<td>0.73</td>
<td>0.59</td>
<td>7.58</td>
<td>32%</td>
</tr>
<tr>
<td><strong>EAP</strong></td>
<td>2.44</td>
<td>2.80</td>
<td>2.25</td>
<td>1.75</td>
<td>0.63</td>
<td>9.87</td>
<td>41%</td>
</tr>
<tr>
<td><strong>ECA</strong></td>
<td>2.70</td>
<td>2.65</td>
<td>2.19</td>
<td>1.36</td>
<td>1.35</td>
<td>10.25</td>
<td>43%</td>
</tr>
<tr>
<td><strong>LAC</strong></td>
<td>4.28</td>
<td>3.00</td>
<td>3.78</td>
<td>0.73</td>
<td>1.00</td>
<td>12.79</td>
<td>53%</td>
</tr>
<tr>
<td><strong>MNA</strong></td>
<td>1.00</td>
<td>2.60</td>
<td>0.67</td>
<td>0.50</td>
<td>0.80</td>
<td>5.57</td>
<td>23%</td>
</tr>
<tr>
<td><strong>SAR</strong></td>
<td>3.00</td>
<td>3.00</td>
<td>3.00</td>
<td>1.33</td>
<td>0.80</td>
<td>11.13</td>
<td>46%</td>
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</table>

### Table 5
Percentage of developing countries with greenfield private investment and privatization

<table>
<thead>
<tr>
<th></th>
<th>Global</th>
<th>AFR</th>
<th>EAP</th>
<th>ECA</th>
<th>LAC</th>
<th>MNA</th>
<th>SAR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Power</strong></td>
<td>IPPs</td>
<td>40%</td>
<td>19%</td>
<td>78%</td>
<td>33%</td>
<td>83%</td>
<td>13%</td>
</tr>
<tr>
<td></td>
<td>Privatization</td>
<td>25%</td>
<td>6%</td>
<td>33%</td>
<td>41%</td>
<td>50%</td>
<td>13%</td>
</tr>
<tr>
<td><strong>Upstream oil/gas</strong></td>
<td>Concessions Privatization</td>
<td>69%</td>
<td>91%</td>
<td>40%</td>
<td>65%</td>
<td>63%</td>
<td>80%</td>
</tr>
<tr>
<td></td>
<td>14%</td>
<td>9%</td>
<td>0%</td>
<td>18%</td>
<td>38%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Downstream gas</strong></td>
<td>Private investment Privatization</td>
<td>27%</td>
<td>33%</td>
<td>25%</td>
<td>22%</td>
<td>56%</td>
<td>0%</td>
</tr>
<tr>
<td></td>
<td>27%</td>
<td>17%</td>
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<td>33%</td>
<td>56%</td>
<td>0%</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Downstream oil</strong></td>
<td>Private refinery investment Privatization</td>
<td>23%</td>
<td>18%</td>
<td>50%</td>
<td>32%</td>
<td>9%</td>
<td>0%</td>
</tr>
<tr>
<td></td>
<td>Privatization refinery</td>
<td>28%</td>
<td>0%</td>
<td>50%</td>
<td>45%</td>
<td>18%</td>
<td>17%</td>
</tr>
<tr>
<td></td>
<td>Privatization wholesale</td>
<td>28%</td>
<td>24%</td>
<td>0%</td>
<td>42%</td>
<td>18%</td>
<td>40%</td>
</tr>
<tr>
<td><strong>Overall energy % of maximum (weighted)</strong></td>
<td>New private investment Privatization</td>
<td>40%</td>
<td>40%</td>
<td>48%</td>
<td>38%</td>
<td>53%</td>
<td>23%</td>
</tr>
<tr>
<td></td>
<td>24%</td>
<td>11%</td>
<td>17%</td>
<td>36%</td>
<td>36%</td>
<td>14%</td>
<td>19%</td>
</tr>
</tbody>
</table>

This table shows that only 24% of countries have yet allowed any form of privatization of existing assets in the energy sector, and only 40% have permitted the private sector to be involved with new investment. There are large regional differences, but even in the two regions with the greatest reform experience (LAC and ECA) not more than 36% have allowed privatization of existing assets, while in AFR, EAP, MNA and SAR this figure is around 15%. There is a notable difference between the willingness to permit private sector participation in greenfield sites and the willingness to privatize existing assets in all regions except for ECA.
Empowering the End-User: Market Reform Lessons from IEA Countries
Jean-Marie Bourdaire*

Several general lessons can be drawn from the experience of energy sector reform in the IEA countries:

- Distribution is where the greatest inefficiencies in the system are – privatization of distribution and retail supply is an essential prerequisite of successful reform.
- Low-income consumers benefit from reform – cost-reflective pricing offers them the lowest possible sustainable tariffs for the services they need.
- Reforms should proceed equally in the gas and electricity markets for either to be a success.

This essay briefly reviews past experience with electricity market reforms, identifying the technological and economic drivers of market reforms. But the essay argues that the central driver of market reforms is consumer choice, and explores how best to reform pricing and sector organization in order to "empower the end-user".

Technology and economics: a brief history of power market reform

In the electricity sector of the IEA countries, the wave of recent market reforms has resulted from a growing awareness of the incapacity of the monopoly utility to adapt to new technologies and to undergo a continuous reform process. These recent reforms can be separated into three periods.

The starting point was the US PURPA (Public Utilities Regulatory Policy Act) enacted in 1978 at a time when it became apparent that economies of scale were no longer significant for industrial combined heat and power systems (i.e. co-generation). Many decentralised "qualified facilities" were built to enjoy the high tariffs associated with the avoided costs of the utilities (up to 9 US cents per kWh). Furthermore, the slowing of economic growth because of the crisis brought by the two oil shocks resulted in large and costly over-capacities which added to the general feeling that utilities' investments were too many and too expensive ("gold-plated investments"). The UK followed the lead in the early 1980s in a context which was even worse than that of North America: on top of the decline in demand, many investments in fuel oil-fired plants had been initiated before the first oil shock, and were redundant when new coal and nuclear capacities launched after 1973 started to come on stream from 1979 onwards.

The second phase of market reforms again originated in the US with the coming on stream of new, small, cheap and reliable gas turbines in the mid 1980s, at a time when the gas price was falling because of parallel reforms in the gas market. This wave of gas reforms was initiated in 1978, and it and the subsequent FERC orders aimed at resolving the contradiction between the rising supply of new liberalised gas and the declining demand due to its costliness. Similar moves spread to Europe. In the Netherlands, pressure from co-generators led the government to lower gas tariffs for big industrial customers. In the UK, the appeal of the regulator to the Mergers and Monopolies Commission, on behalf of the co-generators, led to the actual dismantling of British Gas. More generally in the EU, the gas directive, while not guaranteeing that CHP will have access to cheap gas specifically, is aimed at lowering gas prices through competition and ultimately at ending the "net-back" pricing era. In the Asia-Pacific region, Australia and New Zealand are moving fast towards deregulating both gas and electricity. One common aspect of these different national experiences has been the growing evidence that market reforms have to move at the same time and pace in both the electricity and the gas sectors.

This led to the third and current phase of market reforms, those of the retail sector. In the generation sector in IEA countries, there is not much room left for industrial co-generation: good sites are already equipped and most of the remaining projects are not economic in a context of low electricity prices. However, there is plenty of potential for new small projects for the buildings sector.

This possibility of decentralised gas generation systems in the commercial and residential sector has opened a Pandora's Box. Among the many surprises, the most interesting has been the light shed on those parts of the system which interface directly with the consumer. It has revealed the extent of inefficiencies in the distribution and retail supply sectors, comparable to those in the generation system, and in this author's view even larger. The sources of these inefficiencies are clear: distribution is a natural monopoly and so entails extra costs because yardstick regulation will generally fail to remove the "fat", especially in the case of national public distribution systems. Retail supply, the delivery of electricity to the end-users (which in the monopoly utility model, is bundled together with distribution), is often distorted by cross subsidies among different classes of customers.

*Jean-Marie Bourdaire is the Director for Long-Term Co-operation and Policy Analysis of the International Energy Agency. The opinions expressed in this essay are those of the author and do not necessarily reflect the views of the IEA Secretariat or of its member countries.
The trend towards smaller systems
Decreasing generating unit size in OECD countries, 1967-95

![Graph showing the trend towards smaller systems](image)

Source: UDI power plant database

The unfinished agenda: pricing reform

Reflecting the cost of reliability and security of supply

The greatest challenge in pricing electricity in deregulated systems is how to incorporate the capacity margin. How can pricing lead to an effective management of the generation capacities which minimises the total cost – that is, the cost of providing electricity (generation, transmission, distribution, and supply) and that of failing to provide it (brownouts and blackouts)? If competition works successfully (a situation which is rarely encountered in deregulated electricity markets so far!) it will naturally lead to a price that reflects the short run marginal cost (SRMC) - that is, the highest variable cost (mostly fuel costs) of all the plants running at the time, or even more in case of short-fall of capacity. In a situation of over-capacity, this SRMC will be quite low, say between one and three US cents per kWh. But in a situation of tight capacity it will rise, to around eight US cents per kWh for a distillate driven simple turbine for example, and in a situation of shortage, it may shoot up even further. The result is that without incentives for security/reliability, prices would follow a cyclical pattern mostly determined by the lead time to bring new base load capacities on line (say, six years or more for new coal-fired plants, large dams, nuclear units, new gas supply options via pipelines or LNG carriers) with short-term costs averaging the long-term marginal cost needed to cover the full cost of new units. But such a cyclical pattern is not acceptable, because brownouts or blackouts could be expected to occur at the time of under-capacity, and these entail huge costs for consumers and the economy.

One way of meeting the capacity margin challenge is to use a top-down approach. For example, a "portfolio manager" can decide what level of capacity margin needs to be available to minimize the possibility of disruptions, or, as was initially the case in the UK electricity pool, price triggers which provide a further incentive to invest (the "uplift" and the "loss of load probability") can be established. Needless to say that both these top-down approaches are ad hoc solutions.

A new way of thinking is to avoid such top-down approaches and to prefer a system of bilateral supply arrangements with each supplier having with each of its customers an electricity contract including both the price of electricity and a level of reliability/security chosen by the customer. This additional service would come at a cost and would provide the supplier with extra revenue. The supplier would have to choose its portfolio strategy (which would include reserve capacity margins, fuel diversification, interruptible customers, and so on) in order to honor its set of contracts at minimum cost. In such a system, competition will be the driver to lower total cost minimizing both the commodity cost and the cost of maintaining the chosen level of reliability/security. For its part, government's duty will be to create institutional arrangements in order to ensure that:

- genuine competition exists with no supplier growing too big at the expense of the size and number of competitors (economies of scale exist for providing security, and the natural tendency of the industry will therefore be to concentrate);
- suppliers' financial liabilities will be paid in case of non-delivery. Given a contract similar to that of an insurance with a cost premium for the customer in exchange of a penalty paid by the supplier in case of default, suppliers will have to comply with the same guarantees and financial provisions as for an insurance company.

Reflecting the cost of transmission and distribution

The overall high voltage transmission cost is a small part of the total electricity cost. An order of magnitude would be that of a 60/5/35 split of the average tariff with power generation representing 40% to 70% of the total electricity costs, transmission 5% (less when there is limited interconnection) and distribution 20% to 50%.

Figure 2
Shares of the cost of supply by function
Selected IEA countries

![Graph showing shares of the cost of supply by function](image)

Source: IEA

Transmission cannot be considered in isolation. The economic function of electricity is that of the whole system – generation, transmission and distribution – in a context of partial uncertainty. Hence a deterministic approach to the transmission sector, such as that taken by nodal pricing, is not satisfactory. Electricity systems are not purely deterministic – random events (the break-
down of a line; increased demand due to unexpected harsh weather conditions; etc.) have to be taken into account. Furthermore, transmission, although a key element of the reliability chain, only represents 5% of the total cost. Given this unavoidable uncertainty, the commonsense attitude that a 5% contribution to the total cost should not lead to more than a 5% likelihood of failure, and the need for simplicity to operate the network safely, a more robust approach is preferable to nodal pricing.

The case of distribution is similar to that of transmission, with three important distinctions. Firstly, the relative costs are much higher in the distribution sector because of the large investments (in low voltage lines, metering, maintenance and other ancillary services) needed to deliver small amounts of electricity to end-users. Secondly, the diversity of shapes of the load curves of different categories of customer is much greater in the distribution sector, ranging from nearly flat (i.e. base-load) for large industrial users, to variable for the households as it depends on their metering systems, to highly variable for services (strong day/night patterns and strong seasonal patterns because of the need for heating or cooling). Thirdly, the impact of social policies aimed at providing cheap electricity to low income customers without, if possible, departing from cost-effective pricing is felt in distribution, but generally not in transmission.

Generally speaking, the organisation of distribution is still very inefficient in most IEA countries. Costs are often too high, tariffs are not always cost-reflective, subsidies or cross subsidies may exist, and the capacity of customers to develop their own decentralised solutions is either absent or limited. In developing countries the same problems are encountered, but on a still larger scale because of the social role of electricity, sometimes as a source of employment (hence costs are increased), sometimes as a driver of development (hence prices, which may be quite high in terms of purchase power in these countries, may be lowered and subsidized).

For both transmission (high voltage lines) and distribution (low voltage lines), long-term price signals (capacity costs) should complement the short-term signals (variable costs). The latter – time of-use-nodal pricing – does not provide incentives for capacity expansion unless bottlenecks and high costs occur, a situation clearly unacceptable given the need for a reliable and continuous supply of electricity. The compromise made for gas in the US is that of the straight fixed variable formula. However, one might opt only to retain the capacity element as a realistic compromise between cost-effectiveness, long-term security and simplicity. For transmission, this idea has been developed by Finland; for distribution this is the implicit argument behind the Spanish formula for residential use (Box 1). Such approaches can be usefully developed and extended in developing countries.

### Box 1

**Distribution pricing and low-income consumers: the Spanish model**

In Spain, low-income customers can opt for a low capacity meter, which carry a maximum of 0.77 kW. These customers are compensated for this capacity limit by lower tariffs – a capacity tariff of 22 pesetas per kW, and a commodity cost of 4.83 pesetas per kWh. This compares with the tariffs if the same customer were to choose the regular household meter, which provides up to 15 kW of electricity: 120 pesetas capacity, and 6.85 pesetas per kWh.

**The engine of market reforms: consumer choice**

Acknowledging that the distribution and retail supply sector is one of the key sources – sometimes the key source – of inefficiency in the electricity sector, is the most important contribution policy makers or international organisations can make. With this in mind, neither the capacity-adding IPP approach adopted in some IEA countries and in many developing, nor the progressive introduction of competition for large “eligible” industrial users (such as that initiated by the electricity directive in the European Union, or the present momentum in Japan), should be seen as the best approach to regulatory reforms. These strategies are not necessarily bad since they start a process which hopefully will end-up with the reform of distribution and retail supply, but they do not focus on the true engine of market reforms: the end-user who has both a right – that of choosing his supplier and his contract – and a duty – that of honoring his contract by paying his bill.

In the light of the previous comments, more urgent is the opening of the distribution sector with five central components (Box 2).
Box 2  
Liberalizing distribution: five steps

Privatization: as a means of avoiding the costs associated with the public servant status of the workforce; as a means to "divide to rule" by separating national distribution (when there is a single national entity) into smaller Local Distribution Companies (LDCs), with all large users, including these LDCs, buying directly from the transmission grid; and as a means to create a solvent market.

Competition: out-sourcing, franchising, setting yardstick regulation and more generally creating a competitive spirit among LDCs as a means to make them "lean and mean." The duration of the franchises needs to be long enough, say 10 to 15 years, to ensure that customers can make an informed choice based on both tariffs and quality of service (e.g., how quick the company is to fix the ravages of a storm - lines falling down and power being cut).

Open access: the distribution system must be open to deregulated retail suppliers and large users if cost-reflective tariffs are to be ensured. Although subsidies will normally disappear in a privately-owned system, there is a risk of cross subsidies such as tariffs that favor the customers who could leave the LDC (e.g., average size industries) at the expense of the smaller captive users. Hence there is a need to make the system more transparent, either via open access and competition, or via transparent commodity and distribution costs.

Decentralized systems: making sure that the conditions for launching cost-effective decentralised power systems are met. The advantages are obvious since more decentralized supply means less investment in large power units, transmission, and distribution grids. Two essential components are the price of back-up supply if the decentralized unit cannot meet the level of supply for which it has been engaged, and the sell-back price to the grid in the opposite case.

Fuel supply: ensuring access to the fuel to power such decentralised systems at a cost reflective price. Gas, when it is cheap enough, is generally the preferred fuel for these units because it is easy to use with little technical problems and maintenance. Hence the need to make sure that market reforms will proceed at the same pace for gas and electricity. If this is not the case, gas will be priced at the same level as for domestic/commercial customers (say, at the level of delivered oil distillates) and will be too expensive compared to the gas price in a competitive market (say, close to HFO level).
Reflections on the Politics of Reform

Alfonso Cristobal Revollo*

Alfonso Cristobal Revollo, who oversaw Bolivia's energy sector reform program while he was Minister of Capitalization and Pension Reform, describes the essential political considerations that need to be addressed in designing a successful reform strategy. Foremost among them are labor issues and a good communication strategy: both areas often downplayed by international advisors.

Fear of change: the greatest challenge

Reforming the energy sector is a complicated and difficult matter from a political standpoint. It is important to recall that in many countries, and particularly in Latin America, the energy sector is considered a "strategic" activity. The term strategic was developed during military governments, which incorporated strategic enterprises within their "military doctrine", where the State was the only institution allowed to exploit such resources. Companies in charge of electric energy, telecommunications, aviation, airports, ports, railroads, hydrocarbons and other sectors fall in this category. However, the concept of "strategic" was not limited to the Armed Forces, but was also coined by the general population. In this sense, all such companies are considered part of a "national strategic sector" – and therefore a fundamental part of a country’s sovereignty. Consequently, they can’t be sold to national investors, much less to foreign investors.

Although there is general concurrence in the need to privatize and modernize these sectors – which are often bankrupt, chronically subsidized, have large overhead costs and excessive political interference in their administration including corruption pressures – there is an important consideration preventing the reform process moving ahead easily: fear. Both the political class, and the population at large, fear change, that is to say, changing a sector that has traditionally been run by the government and converting it into a privately-run sector. Because of this, Governments are cautious in accepting that the state’s role – as a norm-maker, regulator and producer – must change fundamentally, leaving its role as producer in private hands.

Essential prerequisites of the reform process

Commitment at the top

Reform of the energy sector, and privatization more generally, is without a doubt a process of technical reform that requires cooperation and assistance from experts in international organizations, investment banks, as well as legal expertise and strategic advisors. If hiring this team of specialists is relatively simple, then why is the reform process itself so difficult?

Since every reform is also a political process, its feasibility requires a sound political implementation strategy. This is especially so when the process has to do with the reform of sectors considered strategic for society. As a result, it is of vital importance that the President of the Republic understands the process of change as well as the technical and political benefits that should result from the reform in a relatively short period of time – in terms of improved services, tariffs now controlled by a regulator, and the elimination of corruption. The President must also be well briefed on other critical issues, such as the elimination of subsidies, layoffs, debt treatment, etc. It is also fundamental to convey the importance of creating a special Ministry exclusively in charge of implementing the reform process. Setting up special Commissions, or handing over responsibility to the Finance Ministry will not help the implementation process because the most formidable opposition is within Congress itself.

The Ministers in charge of the sector will show unconditional, outward support to reforming the sector – but they will also be its greatest opponents. The reason for this is simple: a minister is reluctant to give up absolute power even if it benefits the country. Furthermore, the chief executives of the public companies being reformed are also important opponents. For this reason the official responsible for the reform must have ministerial rank so that he (or she) can actively participate in the sessions of Congress and defend the reform process.

One of the most difficult changes to get agreement on is the creation of an autonomous regulating entity. Resistance is great because it means weakening further the functions of a Minister of State; many countries are tempted to place the regulatory body under the corresponding Minister of the sector, thus starting with a mistake that could later have serious repercussions. Even outside experts and government officials are inclined to compromise on the need to have completely independent regulators.

Mobilizing multi-party support

A reform process requires modern legislation which in turn implies the corresponding approval of specific laws by the country’s congressional body. In many cases, a special privatization law is required to permit the transfer of the State-owned proper-

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ty. Investors will generally wait for the enactment of key sectoral legislation needed to modify the traditional state monopoly and allow private competition and investments. Broad-based political consensus is essential to achieve this. Without it, the legislation required to carry forward the reform will not be approved. It is imperative, therefore, to convince the President how crucial this step actually is in order to marshal the needed support in a reasonable period of time. Even when a strong political coalition has been formed, the process will still be a difficult one.

**Mobilizing civil society**

The armed forces, political parties, NGOs, trade unions, press, national private sector, religious groups, and much of the population at large will tend to oppose the reform process; a political and communications strategy must therefore be developed. The Armed Forces, for instance, must be made to see that the energy and telecommunications sectors cannot be considered "strategic" when there is electricity rationing or significant segments of the population lacking telephones. In a democratic system, it is necessary to have a permanent dialogue and seek consensus with civil society, without changing the reform process or calendar of the reform.

**Addressing the labor issue**

International experts and advisors rarely give sufficient attention to the labor issue, one of the most delicate because it is the working class which will be the most affected by the change. It is important to give serious thought to different options and to avoid the impression that privatization is tantamount to unemployment. The Bolivian experience, for example, is particularly interesting because the workers became shareholders of the privatized companies without this impeding the reform process itself. The workers of the capitalized companies have not only been confirmed as employees but they are now also benefiting from the resulting dividends.

**Designing a communication strategy**

As is the case with the labor issue, outside international experts don’t give enough weight to the importance of communications. Political opposition, union groups and groups of power will always try to stall the reform process. In this sense, the communications program must be carried out by the Ministry in charge and must comprise cost-free communication. It must not just be directed at unions or workers, but also be directed at the population at large in order to first educate them and then secure their support. An ineffective communication strategy will assure failure of the reform process.

**Implementing the reform process**

The Minister appointed to carry out the reform process must organize his Ministry in a simple and efficient way, securing financing, inter alia, from international organizations to cover the costs of national and foreign experts. It is essential to have highly qualified personnel. In most public sectors, salaries are relatively low, which precludes hiring specialized personnel. The reform process must be simple and easy to understand for the purpose of assuring the transparency of the process. From its beginning until its conclusion, the process should not exceed 24 months.

The organization of the Ministry must be supported by several other Government bodies: the judiciary, finance, procurement, labor and communications. In addition, sectoral groups must be organized to help prepare the reform process in each sector, and act as the local counterpart to the international experts and strategic advisors.

The judiciary, finance and procurement offices are of vital importance to give the reform process the necessary agility. The professionalism with which these functions are handled will assure the transparency of the process in the first phase, which is a crucial element for the success of the reform.
The financial crises should not deflect attention from the environmental problems arising from current patterns of energy use, nor from the significant opportunities that are available to meet them:

- The costs of local and regional pollution control are relatively low, and can be met without governmental subsidy.
- The resulting benefits to peoples’ health would improve prospects for macroeconomic growth.
- Renewable energy resources are abundant in developing countries, hold much economic potential, and offer good opportunities for CO2 abatement.

Many of the most cost-effective technologies are decentralized – without the liberalization of energy distribution markets, their use will be stalled.

**Financial shocks, investments in energy supply, and the environment**

Technical progress in pollution abatement has put developing countries in a position where they can aspire to reducing pollution from energy use at a far earlier phase of development than the industrial countries before them. Options are available for virtually eliminating particulate matter (PM) emissions, lead in fuels, acid deposition and a range of other local pollutants that pose the most pressing environmental problems developing countries are facing today. The costs of pollution control are relatively low, around 5% of energy supply costs, and the historical experience of the industrial countries shows that they can be met without government subsidy if good regulatory or market-based environmental policies are put in place. Technologies are also emerging that offer considerable promise for mitigating climate change in the long-term—for example in renewable energy, fuel cells, and hydrogen-related—and which are especially well suited to developing countries, whose renewable energy resources are virtually unlimited. From the perspectives of economics and engineering, there is every reason to be sanguine about the very large future energy needs of developing countries being met and the pollution problems arising from energy use being substantially addressed.

This paper outlines some of the more promising possibilities. But first, it addresses the current concern about the difficulties of financing pollution control at the present time in view of the financial crisis afflicting many countries.

The standard answer to this concern might be that investments in energy supplies and environmental improvement provide an expenditure stimulus in periods when reductions in investment would otherwise be certain to deepen and lengthen a macro-economic crisis. But beyond this, investments in energy infrastructure have a number of financial and other benefits—especially investments that expand, reinforce and improve the management of the distribution networks for electricity and gas. These investments help to restore energy markets and to improve capacity utilisation, and thus increase the returns to existing investments. Consider electric power. Several World Bank studies have shown that considerable levels of unmet demand and energy losses have persisted over several decades in developing countries on account of under-investment in distribution. Investments in infrastructure would thus simultaneously increase the financial returns to existing investments and improve energy efficiency. A further benefit is that they substitute modern energy forms for the highly polluting and energy-inefficient sources of heat, light and power. In financial, economic and environmental terms, therefore, energy infrastructure is an excellent area for investment during financial crises, and of course at other times.

It can also safely be assumed that energy markets will recover as developing countries emerge from the present crisis, and that demands for environmental improvements will increase. Consider their energy demands during the oil price shocks and their aftermath, over the period 1973-ca.1985, which affected developing countries far more severely than the industrial countries. Despite the severity of the shocks, energy demand in all regions grew appreciably – five-fold in the electricity sector in East Asia and Pacific between 1970 and 1985, four-fold in Latin America, two-fold in Sub-Saharan Africa, and two-and-a-half-fold in South Asia. Since the mid-1980s energy markets have roughly doubled in these regions, their per capita consumption of energy is very low, and two billion people are without use of modern energy forms. All the evidence points to continued expansion in the coming decades.

**Local and regional pollution**

Empirical studies have consistently found that local and regional pollution from energy production and use in developing countries have high social costs. Recent reviews of the costs of pollution in large cities have noted the following:

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Environmental costs of fuel use can be so high that marginal damage costs are comparable with or exceed (for some fuel uses) both producer and retail prices. In urban areas, local health effects dominate the damage costs. Marginal damage costs per ton of local pollutants vary greatly across sources and locations, and are much higher for small (low-stack) sources due to the dispersion pattern. Diesel powered vehicles and small stoves or boiler burning coal, wood and oil impose the highest social costs per ton of fuel.

Lead in blood during the early 1990s in Mexico City, Budapest, Cairo and Bangkok were 25, 25, 20 and 40 micrograms per decilitre respectively, as compared with 2 micrograms per decilitre in the US, where it had declined eight-fold over the preceding 15 years. In comparison, the most heavily polluted parts of Central and Eastern Europe—the black triangle—were approximately 15 grams per square meter per year.

Table 1
Relative pollution intensities and costs of polluting and low-polluting technologies for energy production and use

<table>
<thead>
<tr>
<th>Source and pollutant</th>
<th>Polluting practice (all emissions indexed at 100)</th>
<th>Low-polluting practice (as % of polluting practice)</th>
<th>Net private marginal costs (MC) as % of MC of supply</th>
<th>Nature of low-polluting alternatives</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electricity Generation (coal):</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PM emissions</td>
<td>100</td>
<td>&lt;0.1</td>
<td>0 to 2</td>
<td>Natural gas; ESP, BHF, FGD, IGCC and FBC (for coal); 'low NOx' combustion and catalytic methods.</td>
</tr>
<tr>
<td>SO₂</td>
<td>100</td>
<td>0 to 0.5</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>NOₓ</td>
<td>100</td>
<td>5 to 10</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td><strong>Gasoline engines:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pb</td>
<td>100</td>
<td>0</td>
<td>Combined costs of 4-5% of vehicle and fuel used.</td>
<td>Unleaded/reformulated fuels; Catalytic converters.</td>
</tr>
<tr>
<td>CO</td>
<td>100</td>
<td>5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NOₓ</td>
<td>100</td>
<td>20</td>
<td></td>
<td></td>
</tr>
<tr>
<td>VOC</td>
<td>100</td>
<td>5</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Diesel Vehicles:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PM</td>
<td>100</td>
<td>= 10-20</td>
<td>n.a.</td>
<td>Improved fuel injection, engine design, maintenance and 'proper' fuel use. Catalytic converters.</td>
</tr>
<tr>
<td>NOₓ</td>
<td>100</td>
<td>= 40</td>
<td>n.a.</td>
<td></td>
</tr>
<tr>
<td>'Traditional' Household Fuels</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(wood and dung) in low income countries:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Smoke (PM, CO and sulphur)</td>
<td>100</td>
<td>&lt;0.01</td>
<td>= - 20</td>
<td>Wood stoves and flues; Gas, kerosene.</td>
</tr>
<tr>
<td><strong>CO₂ emissions from combustion of fossil fuels:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Electricity (developing countries)</td>
<td>100</td>
<td>0</td>
<td>= 0</td>
<td>Advanced solar energy, wind and other renewable energy technologies for power generation; biomass for liquid fuels and power generation; hydrogen from renewable energy sources and fuel cells for power generation and vehicles.</td>
</tr>
<tr>
<td>Electricity (industrial countries)</td>
<td>100</td>
<td>0</td>
<td>= 20</td>
<td></td>
</tr>
<tr>
<td>Liquid fuel substitutes</td>
<td>100</td>
<td>0</td>
<td>= 30-50</td>
<td></td>
</tr>
</tbody>
</table>

1 The reason for using net private marginal costs as a basis is that some technologies and fuels have justifications that go beyond their environmental benefits. The use of gas as a domestic and industrial fuel is an example. Such investments are routinely justified in terms of their economic convenience or productivity relative to the alternatives, without reference to their environmental benefits, important as the latter are.

2 Acronyms are for Electrostatic Precipitators, Bag-House Filters, Flue Gas Desulphurisation, and Integrated Coal Gasification Combined-Cycle technologies. Note that the negative cost figure arises if gas is available for power generation as a substitute for coal.

3 High emissions especially of PM in developing countries stem very much from ageing vehicles, poor maintenance and improper use of fuels (e.g. kerosene instead of diesel).

4 Cost estimates for the developing countries are much lower than for the northern industrial countries because the incident solar energy is 2-3 times greater in the former regions while its seasonal fluctuation is less than one third. Note that these are long-term estimates.
tion networks, through the improvements in the efficiency of new power plant, and improvements in pricing and regulatory policies. In the case of supplying modern fuels to households, there are three major benefits: very large improvements in energy efficiency, massive reductions in indoor and local pollution, and, except in remoter communities, a significant reduction in the costs of energy supplies.

The low costs of pollution control relative to the costs of energy supply and use further suggest that the required finance could be generated by policies that allowed prices to reflect the marginal costs of supply, including the costs of pollution control – the central goal of ‘internalising externalities’ in market prices. No recourse to subsidy should be necessary to finance investments in local or regional pollution. In conclusion, there is no reason why developing countries could not begin ambitious policies of reducing local and regional pollution from energy production and use.

Global warming

For understandable reasons, developing countries have been reluctant to commit themselves to CO₂ emission reduction targets. There is, however, one respect in which they stand to benefit over the long-term from international policies on climate change and the energy R&D programs of the industrial countries. This, again, is in the area of technology development, of renewable energy and efficient end-use technologies in particular. The area of technology development has become a focal point of the operations of the Global Environment Facility, the financing arm of the United Nations Framework Conventions on climate change and biodiversity. Let us first consider the two main reasons why the use of these technologies is being encouraged—the abundance of the renewable energy resource, and technical developments and costs.

Abundance of the renewable energy resource

The earth receives a yearly energy input from the sun equal to more than 10,000 times the world’s consumption of commercial energy. Solar insolations vary from 2,000 to over 2,500 kWh/m² per year over vast areas of developing countries, as compared with 800 to 1,700 kWh/m² per year in Europe and 1100 to over 2,500 kWh/m² in the United States. Photovoltaic systems and solar-thermal power stations are capable of converting 10 to 15 percent – with further development, 15 to 30 percent – of the incident solar energy into electricity. In theory, an area of land equal to 0.25 percent of the area now under crops and permanent pasture would be needed in theory to meet all of the world’s primary energy requirements of 8 Gtoe per year. There is thus no significant land constraint on the use of solar energy. The main issues concern its storage and costs. The explanation for this still not-widely-appreciated conclusion lies in the achievement, over the past two decades, of good conversion efficiencies for solar devices.

Two other renewable energy technologies – the use of biomass and wind power for electricity generation – have greater land intensities than solar energy, but where the land constraints or visual intrusion are not serious have attracted significant investment already, and for grid connected applications have so far been more economically attractive than the direct solar technologies. Biomass has the additional economic and technical advantage that it can be stored.

### Table 2

**Use and comparative costs of selected renewable energy technologies**

<table>
<thead>
<tr>
<th>Technology</th>
<th>Current Average Cost</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind (electric power)</td>
<td>4.5-6.5 c/kWh</td>
<td>Costs declined five-fold in the period 1985-95.</td>
</tr>
<tr>
<td>Biomass:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>electric power</td>
<td>7.5-8.5 c/kWh</td>
<td>25MW steam cycle</td>
</tr>
<tr>
<td>ethanol</td>
<td>US $1/gallon</td>
<td>Brazil data. Declined by factor of 3 since 1980s.</td>
</tr>
<tr>
<td>Photovoltaic Systems:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>insolation, 2500 kWh/m²</td>
<td>20-30 c/kWh</td>
<td>Based on costs of US $5-7/Wp</td>
</tr>
<tr>
<td>insolation, 1500 kWh/m²</td>
<td>35-50 c/kWh</td>
<td>Costs declined fifty-fold since 1975, five-fold since 1980, two-fold since 1990. Medium and long-term storage a major issue.¹</td>
</tr>
<tr>
<td>insolation, 1000 kWh/m²</td>
<td>50-70 c/kWh</td>
<td></td>
</tr>
<tr>
<td>Thermal Solar (electric power)</td>
<td>8-15 c/kWh</td>
<td>Parabolic troughs. (Latest vintages, ca.1990, v. high insolation areas only.)</td>
</tr>
<tr>
<td>Geothermal</td>
<td>4-8 c/kWh</td>
<td>Costs vary greatly with location.</td>
</tr>
<tr>
<td>Gas-fired, combined Cycle power plant</td>
<td>4-5 c/kWh</td>
<td>Higher figure is for LNG.</td>
</tr>
<tr>
<td>Grid supplies:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>off-peak</td>
<td>2.3 c/kWh</td>
<td>Depends on spikiness of peak</td>
</tr>
<tr>
<td>peak</td>
<td>15-25 c/kWh</td>
<td>Urban areas.</td>
</tr>
<tr>
<td>average</td>
<td>8-10 c/kWh</td>
<td>Rural areas (developing countries)</td>
</tr>
<tr>
<td>average</td>
<td>15 to &gt; 50 c/kWh</td>
<td></td>
</tr>
</tbody>
</table>

All figures are rounded. The estimates are adjusted to 10% discount rates, and are based on the author’s review of the literature.

¹ With battery storage, costs of >US$ 10/Wp in off-grid applications are commonly reported.
Technical progress and costs

The future use of renewable energy will depend on its costs relative to those of using fossil fuels, and of course on taxes or regulations on carbon emissions. The relative costs can only be assessed within broad limits, even assuming reasonable stability of fossil fuel prices. Minor changes in assumptions about the effects of innovation on costs, when extrapolated over long periods, lead to large differences in the estimates of the energy supply mix, as do differences in assumptions about climate change policy. It is possible that (and many hold this view), renewable energy will be confined to so-called ‘niche markets’ in the absence of climate change policies, as they are today; or that (and many others hold this view), with further innovations and scale economies in manufacturing and marketing, they will eventually meet a substantial share of the world’s energy needs. What can be said is that it has been shown that renewable energy forms are capable of meeting world energy needs should the need arise, at costs that are not far removed from those of fossil fuels. Table 2 provides some indications of comparative costs.

These estimates indicate why “niche markets” have emerged for renewable energy in favorable locations: geothermal, wind, biomass for power generation, solar thermal in areas of high insolation; PVs for off-grid markets; and PVs for distributed generation when there is a good co-incidence between the solar peak and the demand peak. Renewable energy installations (excluding hydropower, but including another promising option, geothermal energy) aggregate to around 30,000MW world wide, which is small in relation to the world’s generating capacity (over 3 millionMW), but has been sufficient to provide information on the costs and reliability of the technologies.

Three further points about costs

- Technological progress continues to be substantial for all the technologies noted.
- Developing countries enjoy significant comparative advantages in terms of renewable energy resources. For example, insulations are 2-3 times higher in developing countries than in the northern regions of the industrial countries and have much lower seasonal swings. For these reasons, developing countries may enjoy a five-to-one cost advantage in using direct solar technologies.
- The common practice of average cost pricing, as well as extensive subsidies, have tended to distort analyses of the cost-effectiveness of renewables in developing countries. At peak times, the marginal cost of grid supplies may be 2-5 times the average costs, sometimes more, and in off-peak times one quarter to one third. When there is a good co-incidence between solar peaks and demand peaks there is an economic case for using PV systems for distributed generation.

Besides renewable energy, there are promising options in the form of hydrogen production from natural gas and coal bed methane, hydrogen being an ideal fuel for combined cycle power plants and fuel cells.
Global Warming Post-Kyoto: Continuing Impasse or Prospects for Progress?

Thomas Johansson and Susan McDade*

The past year has seen the two principal inter-governmental processes address global climate change with a new seriousness, but obstacles remain.

- Energy development is at last being acknowledged on the international agenda as a vital component of comprehensive economic and social development.
- The perception that there is a trade off between greenhouse gas emissions reductions and national development persists.

Neither an aid-driven, nor a totally "free-market" approach will bring action on greenhouse gas emissions reduction quickly enough: a way to international agreement on new ways to promote "win-win" options must be found.

Energy for development comes of age

Energy is currently at center-stage in two parallel, inter-governmental processes. The first process, linked to the UN Framework Convention on Climate Change (UNFCCC), is well known and began in 1992. This includes the meetings of the Conference of the Parties (COP) to discuss mechanisms to reach greenhouse gas emissions reduction goals, like the one that recently took place in Buenos Aires, Argentina, in November 1998 (COP4).

The second process is just starting up, having been established by the United Nations General Assembly during its review of Agenda 21, five years after the UN Conference on Environment and Development (UNCED). This review discussed a broad set of issues linking environment and development, including energy. The General Assembly decided to dedicate the ninth session of the Commission on Sustainable Development (CSD), CSD-9, in 2001 to energy and transport. A preparatory process will be organized, with the details to be decided upon by CSD-7, in April 1999.

For the first time, energy per se has been put on the international agenda for direct examination rather than as an adjunct to other international development or environment issues. This presents a special opportunity to look for operational approaches to meeting sustainable energy objectives in the preparations for CSD-9 in 2001. The momentum towards sustainable energy generated through the climate change negotiation process will be an important stimulant to this.

How to share emissions reductions: the key debate at Buenos Aires

Patterns of energy production and use have a direct effect on the global environment. Fossil fuel combustion and carbon emissions from industry are the main contributors to global greenhouse gas emissions that cause climate change.

Figure 1 frames the debate over this issue. The continued destruction of forests and reliance on fossil fuels for economic development will produce ever higher levels of greenhouse gas emissions, particularly from developing countries. Industrialized countries have traditionally been the source of the long-lived greenhouse gases, particularly carbon dioxide, and 61% of the current annual increment is still due to them. However, by 2010 developing countries are forecast to account for half of annual emissions, and by 2025, as much as two thirds. Nonetheless, the long-term cumulative contribution to the increase in atmospheric concentrations has been, and will continue to be, dominated by the industrialized countries well into the second half of the next century. Effective climate change mitigation will require contributions from all parts of the world.

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The main achievement of the Kyoto conference (COP3) in 1997 was the adoption of the Kyoto Protocol which calls for legally binding GHG emission reductions by Annex I countries. It also introduces the Kyoto Protocol mechanisms to help Annex I countries achieve these goals while addressing non-Annex I sustainable development concerns. COP4 in Buenos Aires held in November 1998 agreed on a two-year workplan to reach agreement on the implementation details on a large number of issues related to the goals of the Framework Convention on Climate Change and its Kyoto Protocol, including the Kyoto Protocol mechanisms.

There remains a distinct difference of perspective between North and South that has been reflected in the main issues emerging in the climate change negotiations. While there is unanimity on the importance of climate change as a significant global environmental issue, negotiators in the climate change process have continued to emphasize "common but differentiated responsibility" for greenhouse gas emissions when comparing North and South. The United States in particular has indicated that commitments by major developing countries, whose annual emissions will become more and more significant in the future, is essential before binding domestic emissions reductions in the US can be considered. Developing countries, including China, India and Brazil, have been unwilling to enter into discussions about voluntary emissions limitations until there is clear progress in reducing carbon emissions from the Annex I countries. Thus, there is a serious question as to whether the Kyoto Protocol will enter into force. This conflict was at the heart of the Buenos Aires meeting in November 1998.

The underlying developing country concern is the perception that industrialization is critical for development. This perception is based on the importance of fossil fuels in the development of the industrialized countries, and their importance in the world's energy economy at present. Developing countries are unwilling to entertain any discussions which would limit their national growth and development options. Unless these underlying perceptions are reconciled there will be only hard choices in a zero-sum approach.

At the end of the day, concerns about climate change are not by themselves a sufficient driver for international agreement on reducing emissions, nor the basis for a consensus to move forward.

**Reconciling the objectives: national development and global climate change**

It has been observed that a combination of increased energy efficiency, more utilization of renewable sources of energy (especially through the modernization of biomass), and the development and introduction of new, inherently clean technologies for fossil fuel use, may address the whole set of issues related to both socio-economic growth and to the local, regional and global environment. Climate change and national development objectives can be reconciled as the same energy policies address the one, and support the other. Such win-win approaches to energy must be pursued.

The key opportunity is related to the fact that now and increasingly so in the future, developing country markets will be the key new theaters for technology innovation and the application of new approaches to delivering energy services. This is based on the fact that both increasing economic prosperity and growing populations imply much greater future energy investments in developing countries. In most cases this will be new additions to the existing capital stock or energy infrastructure, which are unlikely to be applied on a large scale in OECD countries in the near term, because of the more limited growth rates, and the large existing capital stock.

From Rio de Janeiro to Istanbul the international community has consistently emphasized the need for improved energy efficiency, the commercialization of renewable energy, technology transfer, and legislative and price reform to create an "enabling environment" to meet the social and environmental objectives of energy policies at the national and international level. The basic elements of a global strategy for sustainable energy are encompassed, though in a piecemeal fashion, through the statements and accords negotiated and agreed within the inter-governmental process of the UN conferences.

The Kyoto Protocol of December 1997, stresses the need for operational mechanisms to reach these objectives. It makes provisions for industrialized countries to finance emissions reductions efforts through activities that could, at the same time, benefit developing countries by providing financing for low emissions, modern energy technologies.

This has opened the door for potentially substantial investments in energy technologies that at the same time promote national development objectives and pursue climate change goals. This, accompanied by time bound emissions reductions commitments by the industrialized countries, injected a new seriousness into the climate change process. In this respect, the Kyoto Protocol was a major achievement. It also showed that national and global sustainable development goals are not necessarily based on competing objectives in relation to energy.

**Moving the agenda forward: elements of a strategy**

The many social and economic issues related to sustainable national development concerns and the environmental impacts of energy at the local, regional and global level all point to the need for major changes in national and global approaches to energy. A transition to a new energy system is required. In the past, major energy supply changes have been driven by resource scarcity and technological innovation. Since the next such transition will not be driven by resource scarcity for several hundred years to come, based on existing carbon-based fuel reserves, there must be other drivers for change.

New approaches to constructing regulatory environments, stimulating appropriate technology choice and defraying short term risk to capital investment are needed to bring about sustainable energy investments in developing country markets. Existing institutional, regulatory and financial mechanisms must be reexamined with a view to creating such conditions. To be successful in reaching social, economic and environmental objectives these conditions must create incentives for greatly improved
energy efficiency, the expanded use of renewable energy technologies and leapfrogging to modern clean energy technologies in emerging markets. This in turn will depend on the ability to find new mechanisms for government, the private sector and investment finance sources to work together to pursue common energy objectives. Here, the role of official development assistance and inter-governmental processes can be catalytic in enabling this transition to occur.

During the early 1990s global capital investments in energy supply annually were approximately US$ 240-280 billion. This is expected to rise to perhaps US$ 370-570 billion/year by 2020 according to the World Energy Council, about half to two thirds of which will be for the power sector. Conversely foreign aid for both technical assistance and investment projects is declining steadily. Total official development assistance (ODA) in 1996 was US$ 65 billion down from US$ 74 billion in 1986. This refers to all aid for all sectors in all countries. Foreign aid devoted to expanded energy supply is only a fraction of this and reached US$ 8 billion/year in the 1980s. In 1998, World Bank lending for electric power and other energy projects totaled just over US$ 2 billion, or 7% of total lending.

The difference in the orders of magnitude between the levels of total investments in energy and energy sector development assistance clearly underscores the growing importance of investment, especially international foreign direct investments, for creating new energy supply and delivering new services. It also suggests that development assistance directed to energy issues must be used more strategically and focused more directly on environmentally sustainable approaches. New roles and relationships between the international private sector and the international public sector, as represented by aid mechanisms, must be established to reach global energy objectives where they are common, and to promote new forms of project financing and design where they are not.

Focusing on the positive aspects of environmentally sustainable development, especially the sustainable energy elements called for in this decade's UN global conferences, may be more effective in generating support for climate change mitigation efforts than a strategy which emphasizes primarily the need for limiting worldwide energy production and consumption. However, this pro-development and growth focus can only be achieved sustainably if there is a major re-orientation in the production and consumption of energy based on changes in technology choice and medium term investment evaluation. Under a business-as-usual scenario this will not occur; under an aid-driven scenario it is unlikely to occur; and under totally "free market" conditions, it will not occur within a timeframe that is environmentally meaningful.
Access to Modern Energy:
A View From Africa

Stephen Karekezi*

The African energy sector, characterized at present by reliance on traditional biomass and very low levels of access to modern energy for the urban and rural poor, has embarked on the path of reform in several countries.

- Regulatory institutions must resist the creation of private monopolies which will more than likely repeat the errors of their public predecessors.
- Local participation will be essential if power sector reform is to succeed.
- Privatization of distribution should be a first priority – its relatively low capital costs would allow local ownership, and end-users would necessarily be involved.

The impact of ongoing macroeconomic reforms will have a major effect on the development of African energy sectors, and the availability of modern energy services to the poor.

The impact of macroeconomic reforms

As the urbanization of Africa gathers pace, the demand for modern energy is likely to increase substantially. Sub-Saharan Africa’s energy sector will begin to acquire the characteristics prevalent in Northern and Southern Africa. This implies major increases in demand for modern energy services. This would, however, be subject to rising real incomes for the majority inhabitants of sub-Saharan Africa. The impact of macroeconomic reforms that have been implemented in most of sub-Saharan Africa are important in this respect. Should the reforms succeed in increasing incomes and generating economic growth, effective demand (i.e. demand backed by the ability to pay for it) for modern energy services will grow.

There are indications that macroeconomic reforms are generating rising incomes in rural areas of Africa which could potentially translate to increases in the effective demand for modern energy services. There is some anecdotal evidence that the relatively successful dissemination of solar photovoltaic (PV) systems in rural areas of Kenya is linked to rising incomes of rural farmers. Many of the installed PV systems are found in the homes of farmers with relatively high incomes from the sale of cash crops. The ongoing liberalization of cash crop marketing in most sub-Saharan African countries is expected to increase the income of rural farmers which is turn should lead to increases in demand for modern energy services. The continued weakness of international world prices of agricultural commodities, however, could reverse this trend. In the short term, it appears that the growing global deflationary pressures are unlikely to result in rapid increases in world prices for agricultural commodities.

Box 1
A snapshot of the African energy sector

Energy consumption per capita is low and stagnant. Between 1980 and 1995, per capita consumption of modern energy in Sub-Saharan Africa has remained stagnant – falling slightly from an average of 248kgs of oil equivalent (kgoe) to an average of 238 kgoe – consistently around one half the average consumption for all low and middle income economies, and less than a fifth of the world average.

Energy intensity varies widely across Africa. South Africa, with an estimated energy intensity of 1.13 toe for every US$1,000 (1987 US$) is probably the most energy intensive country in Africa. The energy intensity of the North and Sub-Saharan regions is a matter of dispute – its calculation depends crucially on accurate estimates of the level of traditional and biomass energy use.

Urbanization is changing energy needs. In sub-Saharan Africa, where the rural population routinely account for close to 70% of the population, traditional energy use, mainly in the form of unprocessed biomass, dominates the energy sector. However, urban population growth in most Sub-Saharan countries is almost double the overall rate, with the increase in demand for modern energy services accelerating proportionately.

Regional differences mean strong potential for inter-regional exchange of experience. Great differences in energy consumption patterns and energy sector development between different regions present substantial opportunities for the exchange of technical expertise and political experience. North Africa, predominantly an oil and gas producing region, consumes 30% of the continent’s total generated electricity. South Africa, largely dependent on coal, consumes 50% of the continent’s total generated electricity. Sub-Saharan Africa, mainly reliant on traditional biomass energy, consumes 20% of the continent’s total generated electricity.

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Biomass and other renewables

Biomass is still Africa's energy staple. Reliance on traditional biomass energy is particularly high in sub-Saharan Africa, accounting in some countries for 70-90% of primary energy supply and up to 95% of the total consumption. Even oil rich sub-Saharan African countries continue to rely on biomass energy to meet the bulk of their household energy requirements. In Nigeria, it is estimated that about 91% of household energy needs are met by biomass. Biomass use has severe environmental drawbacks. The indoor air pollution from unvented bio-fuel cooking stoves is probably a major contributor to the incidence of respiratory diseases, a major cause of death throughout Sub-Saharan Africa. Reliance on biomass also encourages deforestation and land degradation. In some areas (for example around Lusaka, Zambia) biomass energy use is the major cause of these problems.

Many unexploited opportunities remain. Despite its problems, biomass also offers attractive opportunities: estimates indicate that 85% of current electricity generation in 16 Eastern and Southern African countries could be fuelled by bagasse-based co-generation in the region’s sugar industry. Exploitable hydro power capacity in Africa is massive, but less than 7% has been harnessed - one of the world's lowest figures. Africa has an estimated proven geothermal potential of 9,000MW but only 45MW (in Kenya) has been exploited. The average insolation in Africa is between 5-6 Kwh/m², but solar energy use is still dominated by traditional applications of direct solar energy to dry crops. Encouraging results with PV systems have been registered in Ghana, Kenya, Zimbabwe and South Africa. In spite of abundant potential, the use of solar water heaters in households and institutions is still limited. Some encouraging endeavors are now underway in North Africa (notably Morocco and Tunisia), and in Mauritius and the Seychelles.

The impact of macroeconomic reform on the urban areas appears not to have been as positive as in rural areas of sub-Saharan Africa. In the near term, reforms appear to have resulted in contraction of the public sector leading to short-term increases in urban unemployment and lower urban incomes. The impact on the urban energy sector is demonstrated by the rising number of illegal electricity connections and frequent attempts to avoid the taxes and duties imposed on petroleum fuel products. In the medium to long-term, there is some evidence of the beneficial impacts of macroeconomic reforms in urban areas in terms of increased economic activity largely linked to growing activity in the agricultural sector and some increases in foreign direct investment. The rapid increase in electricity demand in Ghana and Uganda is partially linked to the successful implementation of macroeconomic reforms which have engendered rapid increases in demand for electricity from households, commercial concerns and industry. There is some evidence, however, that low-income urban groups have not benefited equally from macroeconomic reforms and have, therefore, not been able to enjoy substantial increases in the provision of modern energy services. The challenge to devise appropriate response options to address the modern energy needs of low-income urban households remains.

Oil and Gas. Total oil production in Africa for the year 1991 was 329.7 million tons, found mostly in North Africa and in the Western coastline. Although total oil consumption in 1991 was only about 2.0 mb/d, estimates by the IEA project a doubling of oil products consumption in Africa by 2010. Although the African continent has about 15 million km² of sedimentary basin (17.5% of the total sedimentary basin in the world), only about 4% of the total world petroleum exploration/production expenditure to date has been in Africa. The extent and pace of petroleum exploration/production in Africa is at present decreasing rather than increasing, so that in the near term, oil production is unlikely to rise very rapidly.

Coal. South Africa accounts for around 92% of Africa’s coal production, and it is estimated that 90% of the continent’s proven and economically attractive coal reserves and a substantial portion of its uranium deposits are located in South Africa, Zimbabwe and Namibia. Increased use of coal is beginning to generate the common environment problems associated with coal use throughout the world. Examples include indoor air pollution, local air pollution and land degradation (in the case of open cast coal mines).

Power sector reform – the current situation

In the last 10 years, power sector reform has been, in many respects, the most important development in Africa’s energy sector. The need for the reform arose from, firstly, the dissatisfaction over the poor performance of the power sector; secondly, the inability to mobilize sufficient investment capital for conventional power sector development and expansion. The main reform initiatives stressed the introduction of IPPs; vertical unbundling of national electricity utilities (the separation of generation assets from transmission and distribution assets); and commercialization of national power companies. Most of the ongoing and planned IPPs have opted to install thermal power generation units. With the exception of Uganda and Zimbabwe, private sector financed and operated hydro and coal power stations in Africa have been relatively rare.

Although electricity sector reform, along the lines previously discussed, is a relatively recent development that gathered steam in the early 1990s, its rapid and continent-wide application has important implications for Africa’s power sector. In effect, fundamental changes have been achieved. In West and North Africa, power sector reforms have begun to yield results in the form of increased efficiency of utilities and reduced need for Government subsidies to the power sector. In East Africa, notably in Kenya, IPPs have been instrumental in reducing crippling electricity supply shortfalls. The importance of power sector reform is demonstrated by the fact that in some African countries, the installed capacity of planned and ongoing IPPs often dwarfs the installed capacity of existing state-owned electricity generating stations.
The generation pattern is highly uneven. The power sector is dominated by South Africa which in 1992 generated 44 GW. The rest of Africa accounted for 51 GW. Most of South Africa’s electricity was from coal (93.5%) while the rest of Africa produced electricity from a balance of hydro (35.9%), oil (33.5%) and gas (27.1%). Most of the electricity generated in North Africa and oil producing sub-Saharan African countries is from either oil-fired or gas-fired power stations. The rest of Sub-Saharan Africa is largely reliant on hydro-based electricity although the situation is beginning to change.

Access for the poor continues to be inadequate. Energy services for low-income urban households and the rural poor are increasingly scarce and costly. Electrification levels are still woefully inadequate. Most electrification is confined to productive enterprises and high-income rural and urban households.

<table>
<thead>
<tr>
<th>Country</th>
<th>Percentage of Households Electrified</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Urban</td>
</tr>
<tr>
<td>Malawi</td>
<td>11.00%</td>
</tr>
<tr>
<td>Tanzania</td>
<td>13.00%</td>
</tr>
<tr>
<td>Lesotho</td>
<td>14.00%</td>
</tr>
<tr>
<td>Mozambique</td>
<td>17.05%</td>
</tr>
<tr>
<td>Zambia</td>
<td>17.85%</td>
</tr>
<tr>
<td>Namibia</td>
<td>26.00%</td>
</tr>
<tr>
<td>Botswana</td>
<td>26.48%</td>
</tr>
<tr>
<td>Swaziland</td>
<td>42.00%</td>
</tr>
<tr>
<td>Zimbabwe</td>
<td>64.72%</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td><strong>25.78%</strong></td>
</tr>
</tbody>
</table>

The extent and speed of electricity sector reform has, as expected, generated significant controversy. In many French-speaking countries of West Africa, labor unions have resisted power sector reform. In many cases, power sector reform has been followed by major electricity tariffs increases that have resulted in protests from industries and consumers. In Eastern and Southern Africa, the resistance has emanated mainly from Government Ministries and existing national utilities. The advent of IPPs has also generated controversy with major allegations of non-transparent sale of electricity assets or licenses to IPPs. IPP-associated controversies have been particularly acute in Kenya, Tanzania, Uganda and Zimbabwe.

Power sector reform - future challenges and opportunities

While few African decision-makers question the underlying rationale of electricity sector reform, there are concerns that poor implementation of power sector reforms could lead to several negative results, namely:

- the replacement of public power monopolies with de facto private monopolies largely as a result of institutional capture of the relatively weak and newly-established power regulatory agencies.
- the demise of electrification programs aimed at the urban and rural poor.
- the creation of an uneven playing field inimical to the promotion of renewables and energy efficiency.
- the failure to involve local investors in the newly privatized electricity industry thus excluding a potentially important local stakeholder group - a crucial pre-requisite for successful implementation of power sector reform.

Local participation

The key response that would address the above potentially serious shortfalls is increased local participation in power sector reform. This would range from involvement of local African energy experts in power sector reform preparatory and impact studies to broader involvement of important stakeholders that represent the interests of key constituencies (rural and urban households, renewable and energy efficiency community, industry and commercial sub-sectors). The growing pool of local African energy experts can provide the required local inputs to national and regional reform initiatives. In addition, to the growing energy expertise found in African Ministries of Energy, utilities and Universities, the most notable development has been the growth of independent policy research institutes that have been beginning to acquire a critical mass of local African energy policy experts and analysts. Notable examples include the Kumasi Institute of Technology and Energy (KITE) in Ghana, the African Energy Policy Research Network (AFREPREN) in Kenya and the Southern Centre on Energy and Environment (SCEE) in Zimbabwe.

To date, power sector reform has been almost exclusively in the hands of senior Government and utility decision makers, financing agencies, bilateral and multilateral agencies, and suppliers of equipment and technical services. As a result, public understanding of power sector reform is poor, leading to ambivalence at best, and outright hostility at worst. Broader participation and proactive information dissemination on power sector reforms issues would increase awareness, ensure that local concerns and suggestions are incorporated, and garner long term support and commitment for the proposed reforms. A good example of such an initiative is the Government of Uganda’s effort to involve its citizens in the privatization program through intensive information dissemination and encouragement of public debate and discussion fora. As a result, support for privatization has grown and the public debate appears to have shifted from the question of whether to privatize to secondary concerns such as how to privatize, and how to do so in a transparent way.

Focus on distribution

Another important response option would be to focus power sector reforms on the distribution end of the electricity sector instead of the generation end. While reform of the distribution of electricity is difficult and complex, it offers important opportunities. For example, in contrast to generation, the capital requirements of distribution are relatively modest. Thus enabling the involvement of capital-constrained local investors. Distribution, by its very nature, requires the involvement of end-users thus providing an effective mechanism of implementing the aforementioned call for broader involvement of local stakeholders. From a technical viewpoint, reform at the distribution end of the African power system is particularly attractive because that is precisely where most of problems of the electricity sector originate. In general,
generation is relatively efficient even when it is dominated by Government-owned utilities.

Options for renewables

Recent experience in the Latin American energy sector could provide model options for ensuring that programs on rural energy, renewables and energy efficiency are not marginalized in the newly reformed energy sector. With appropriate policy instrument support, it is possible to attract private sector investment in rural energy development as well as promote renewables and energy efficiency. One initiative that is being pioneered in Argentina by the Global Environment Facility (co-managed by the World Bank, UNDP and UNEP) and that could be profitably adopted in Africa is the concession-type instruments which is an adaptation of the oil exploration concession instrument for rural energy, renewables and energy efficiency development. With increased interest in renewables and energy efficiency as result of the international Climate Convention, Africa is well placed to attract grant and concessionary financing to pursue innovative rural energy, renewables and energy efficiency initiatives.
Access to Energy Services – a Brighter Future?

Mark Tomlinson*

The level of access to modern energy is still extremely low throughout most of Sub-Saharan Africa. Two principles will be critical to the development of African energy sectors if they are to meet this challenge successfully:

- Private participation.
- Local ownership.

The poor can and will pay: but markets for energy services must reach them first.

Why access matters

Between 1970 and 1990, Africa’s population increased by about 150 million, but over this period the number of people with access to electricity increased by only about 50 million. Of the approximately one-third of Africa’s population who live in urban areas, only about 25% have access to electric power; while in rural areas, which is where more than two-thirds of Africans live, less than 2% have access. The inescapable conclusion is that more Africans – not fewer – are being excluded from opportunities to participate in development. Energy services are not, of course, the solution to all development problems. But modern energy services are one of the essential components. It is a fact that no country in the world has succeeded in moving significantly beyond a subsistence economy without a broad share of the population having minimum access to modern energy services.

Private participation

With private sector interest in the energy sector gaining momentum, isn’t the problem of access going to be solved by the market in the next few years? The answer is, “No”. For the next decade, the ‘business as usual’ scenario probably is that the situation will continue to deteriorate, or at least not improve. Private sector interest in Africa’s energy sectors is growing. Over the past few years, private capital has financed an increasing number of investments in developing country energy sectors. But most of this investment goes to just 12 countries, none of them in Africa. So far, Africa has been successful in attracting only a small percentage of this private capital because of the constraints described in Box 1. Other international markets will continue to offer attractive energy investment opportunities, many of them in countries perceived to offer lower investment risks.

It is going to take time for private participation in African utilities to invigorate progress on access to energy services, at least to a point where it makes a significant difference. While private participation in Africa’s energy sectors is, in the view of the Bank Group, the most promising way forward for utility development, this can be only part of the solution to promote broader access, only one front in this aspect of the fight against poverty. Other efforts are needed as well, without which it is difficult to anticipate breaking the trend of stagnant or declining access. It is going to be a difficult trend to break: the majority of Africans live in rural areas and access in these areas is extremely low – an order of magnitude less than in urban areas. Incomes in these areas also are much lower than in urban areas; indeed in many countries large segments of the rural population live outside of the money economy altogether. It is understandable, therefore, that new connections in these areas (and in many peri-urban areas as well) will not be the natural priority of the private operators or owners of energy utilities. New utility service connections will be facilitated to the extent that efficiency improvements, tighter financial management and liberalization of tariffs make additional resources available under private ownership or operation. But these investments will take place only to the extent they are justified in hard commercial terms, including the management of investment risks (which are certainly not lower in rural areas).

Box 1
Constraints to private capital flows

For the majority of African countries, rates of private investment in energy will be throttled both by the ceiling on currency convertibility and the financing capacity of the domestic energy sector. Thus, while power shortages in many African countries are acute, the limited financial capacity of the sector restricts the possibility for private investors to help address this problem. To a large extent, this financial constraint is the legacy of poor management of public utilities by governments: utility tariffs have been held below cost recovery levels to pursue social objectives and utilities have not been subject to adequate regulation to safeguard efficiency. The end result is that many African energy sectors are rather small compared with the financing needs of private projects. This situation will take time to turn around. For each country such as Cote d’Ivoire, having average retail power tariffs of about 11 US cents and good recovery of billings, there are others with tariffs of only 2, 3 or 4 US cents and where revenue recovery is a persistent problem.

With this caveat, we can be confident that sectors under private management will do much better than those that remain under

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public ownership. In these countries access will develop more quickly than otherwise would have been the case. But the scale of the task in Sub-Saharan Africa is daunting. With access to grid electricity across Sub-Saharan Africa overall less than 10%; even a three times increase in the rate of new connections would still only keep service extensions in balance with population growth.

Box 2
Potential markets amongst the poor

We know from examples across Africa that many entrepreneurs provide supply for their own manufacturing or service activity through private generation. They pay very high prices: 20 US cents, 25 US cents or even 30 US cents per kWh, a large multiple of the cost of grid supply. Why do they do this? Because the value added of energy services to their business exceeds this cost and still (even at these rates) provides an interesting commercial return. A similar situation exists with households using micro generators or even batteries: here the cost can run to more than US$1 per kWh. Why is it worth it? Because the perceived net-backs to consumers, through time released to participate in health and education programs, exceed even this extreme cost. Overall, people in developing countries spend 12% of their income on energy services, more than five times the average in OECD countries. As a revealed preference, energy is high on the agenda of those struggling to grow out of poverty.

There needs, therefore, to be some additional tool to help spur progress on this problem. With the very best of intentions, African governments, with the support of the international development community, have for many years largely been pursuing a utility model of service extension (and mostly a public utility model) mirroring the development path of many now developed economies. In Africa, this is not going to be enough. Without some other additional means of tackling this problem – sufficient to break the trend of declining or stagnant access – it is difficult to anticipate a significantly greater share of Africans being able to participate in development and grow out of poverty.

Local ownership

The solution, perhaps, lies within Africa itself, in the hands of the tens of thousands of entrepreneurs struggling to initiate a myriad of small private ventures. Another part of the solution may lie within African communities, among chambers of commerce and township and village councils. These are two significant resources so far largely untapped in endeavors to provide basic energy infrastructure. In countries willing to liberalize entry into the energy sector, liberalize prices (or at least release the requirement for a uniform national tariff) and relax technical supply standards for independent energy systems, a partnership between entrepreneurs and local communities can offer hope of accelerating progress on access.

But how is this possible when there is little or no market? What has been lacking are the institutional, financial and technical means to extend supply to more consumers for whom energy services have high value-added, and who are willing to pay cost-reflective tariffs. As Box 2 reveals, the market among those not connected, it seems, is there; we have been seeing the signs for some considerable time and while it is not a market to provide universal coverage in a township or village, it is a market to provide limited supply into high-value end-uses which themselves will be engines of growth in their local economy. Rising local incomes will promote further connections.

Local community involvement will be a critical factor. This will help identify priorities for supply – the end-uses where energy can have most development impact on the local community – and will help ensure needed financial discipline. It is likely that there will be a role for foreign strategic partners as well, for example in franchising a range of technical solutions to the local town-based or village-based companies and providing maintenance and billing services. These technical solutions are likely to range between private distribution companies, taking bulk supply from the grid utility or a private generator, to different types of off-grid energy systems based on mixes of renewable and conventional technologies (for example, micro run-of-river hydro, photovoltaics, and mini gas turbine or diesel installations). The private companies may also include services of LPG or liquid fuels distribution, to encourage substitution for wood fuels and biomass.

What is being proposed is a radically different approach in working with governments to open up and accelerate access in this way. The first is to help establish regimes of sector regulation that embody the necessary flexibility on pricing, technical standards of supply and licensing. The second is to craft financial instruments that are able to provide small amounts of financing to the local private energy companies, and to the local communities themselves. The potential benefits are considerable to millions of Africans. Broader access to energy services will help unlock their initiative and entrepreneurial talents, qualities which can secure a brighter future if the new approach can be made to work.
Appendix I
World Bank Group Financing for the Energy Sector

Please note that these tables include provisional amounts and do not necessarily represent the final amounts committed or disbursed.

Table 1
World Bank Group financing for the energy sector, 1993-98 (US$ million)

<table>
<thead>
<tr>
<th>All Lending</th>
<th>Energy Lending</th>
</tr>
</thead>
<tbody>
<tr>
<td>IBRD / IDA</td>
<td>21,552</td>
</tr>
<tr>
<td>IFC</td>
<td>1,654</td>
</tr>
<tr>
<td>MIGA Guarantees issued for energy projects in Argentina, China, Honduras, Indonesia, Nepal, Jamaica, the Philippines, and Tunisia.</td>
<td></td>
</tr>
</tbody>
</table>

Table 2
IBRD and IDA lending to the energy sector in FY98 and FY99 (provisional, to March)

<table>
<thead>
<tr>
<th>FY98</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bangladesh</strong></td>
</tr>
<tr>
<td><strong>Bosnia and Herzegovina</strong></td>
</tr>
<tr>
<td><strong>Bosnia and Herzegovina</strong></td>
</tr>
<tr>
<td><strong>Brazil</strong></td>
</tr>
<tr>
<td><strong>Chad</strong></td>
</tr>
<tr>
<td><strong>China</strong></td>
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<tr>
<td><strong>China</strong></td>
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<tr>
<td><strong>Ethiopia</strong></td>
</tr>
<tr>
<td><strong>India</strong></td>
</tr>
<tr>
<td><strong>India</strong></td>
</tr>
<tr>
<td><strong>Kyrgyz Republic</strong></td>
</tr>
<tr>
<td><strong>Laos PDR</strong></td>
</tr>
<tr>
<td><strong>Macedonia, FYR</strong></td>
</tr>
<tr>
<td>Country</td>
</tr>
<tr>
<td>------------------</td>
</tr>
<tr>
<td>Poland</td>
</tr>
<tr>
<td>Russian Federation</td>
</tr>
<tr>
<td>Senegal</td>
</tr>
<tr>
<td>Turkey</td>
</tr>
<tr>
<td>Ukraine</td>
</tr>
<tr>
<td>Vietnam</td>
</tr>
<tr>
<td>Zambia</td>
</tr>
</tbody>
</table>

**FY99**

<table>
<thead>
<tr>
<th>Country</th>
<th>Amount</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Argentina</td>
<td>IBRD – US$ 46.5 million.</td>
<td>The granting of concessions to power suppliers in remote areas will be supported, with an emphasis on encouraging rural markets for renewable energy services. Total cost: US$ 210 million.</td>
</tr>
<tr>
<td>Bangladesh</td>
<td>IDA – US$ 70 million.</td>
<td>A partial risk guarantee will be issued for a privately-financed independent power project in Haripur. Total cost: US$ 175 million.</td>
</tr>
<tr>
<td>Cape Verde</td>
<td>IDA – US$ 21.8 million.</td>
<td>A program of capacity expansion will be undertaken which will leave a third of Cape Verde’s grid supply generated by renewables. Total cost: US$ 55.5 million.</td>
</tr>
<tr>
<td>China</td>
<td>IBRD – US$ 100 million.</td>
<td>This loan will assist in the establishment and business development of energy service companies (ESCOs) to facilitate energy efficiency investment programs. Total cost: US$ 200 million.</td>
</tr>
<tr>
<td>India</td>
<td>IBRD – US$ 210 million.</td>
<td>This adaptable program loan will support the reform and restructuring of the power sector in Andhra Pradesh. Total cost: US$ 482 million.</td>
</tr>
<tr>
<td>Yemen</td>
<td>IDA – US$ 54 million.</td>
<td>Through the construction of a new generation plant and the rehabilitation of the existing system, supply constraints will be relieved and growing demand met, particularly in the Sana’a area. Total cost: US$ 60 million.</td>
</tr>
</tbody>
</table>
Table 3.
IFC financing for the energy sector, FY98 and FY99 (provisional, to March)

Note:
US$ amounts are for the total project financing facilitated by IFC (i.e. including syndications as well as IFC loans, equity, and quasi-equity).

<table>
<thead>
<tr>
<th>Country</th>
<th>Amount (US$)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>108.5</td>
<td>Albania US$ 108.5 million. Anglo Albanian Petroleum Ltd. will partly rehabilitate Patos Marinza oil field using enhanced oil recovery. The project is expected to increase output, clean up past environmental damage, and generate foreign exchange.</td>
</tr>
<tr>
<td>Argentina</td>
<td>5</td>
<td>Argentina US$ 5 million. This investment will increase IFC's existing equity stake in the Neuquen Basin joint venture oil production project, to fund extra development costs following the successful appraisal of the Loma Negra field.</td>
</tr>
<tr>
<td>Azerbaijan</td>
<td>100</td>
<td>Azerbaijan US$ 100 million. The Azerbaijan International Operating Consortium's Early Oil Project will develop new oil fields in the Caspian sea off the Apsheron peninsula.</td>
</tr>
<tr>
<td>Cameroon</td>
<td>265</td>
<td>Cameroon US$ 265 million. Pecten Cameroon Company will reduce expected declines in Cameroon's oil production by improving recovery from mature fields and initiating production from marginal fields.</td>
</tr>
<tr>
<td>Cote d’Ivoire</td>
<td>78.5</td>
<td>Cote d’Ivoire US$ 78.5 million. Cinergy S.A. will build two 150MW turbines in Azito on a BOOT basis to be fueled with local natural gas, and an electricity transmission line. The project will be one of the lowest-cost generators in Africa.</td>
</tr>
<tr>
<td>Cote d’Ivoire</td>
<td>5</td>
<td>Cote d’Ivoire US$ 5 million. IFC will increase its FY97 equity investment in the Block Cl-11 Hydrocarbon Development oil venture to an authorized limit of US$ 48.7 million.</td>
</tr>
<tr>
<td>Georgia</td>
<td>6</td>
<td>Georgia US$ 6 million. The Ninotsminda oil field near Tbilisi will be further developed through the drilling of five more wells.</td>
</tr>
<tr>
<td>Guatemala</td>
<td>2</td>
<td>Guatemala US$ 2 million. IFC increased a syndicated loan for a FY97 geothermal power plant.</td>
</tr>
<tr>
<td>Kazakhstan</td>
<td>35.6</td>
<td>Kazakhstan US$ 35.6 million. Kazgermunai, a Kazakh-German joint venture company, will develop the Akshabulak oil field in central Kazakhstan. The project is expected to recover about 113 billion barrels of oil over its 20 year life.</td>
</tr>
<tr>
<td>India</td>
<td>20</td>
<td>India US$ 20 million. Infrastructure Development Finance Company Ltd. will on-lend to infrastructure projects, concentrating in the power sector.</td>
</tr>
<tr>
<td>Mexico</td>
<td>120</td>
<td>Mexico US$ 120 million. AES Merida III, S de R.L. de C.V. will build a 484MW dual fuel power plant near Merida to sell its output to CFE, the state-owned electric utility. It will operate on natural gas or diesel fuel.</td>
</tr>
<tr>
<td>Russian Federation</td>
<td>32</td>
<td>Russian Federation US$ 32 million. AO Mosenergo, Russia's largest regional utility, will expand and complete the upper and lower reservoirs of its Zagorsk pump storage hydropower station, to boost capacity by 200MW.</td>
</tr>
<tr>
<td>Senegal</td>
<td>18.91</td>
<td>Senegal US$ 18.91 million. IFC augmented its investment in GTI Dakar LLC, to cover cost increase in its 50MW combined cycle power plant.</td>
</tr>
</tbody>
</table>
Appendix 2
Who's Who in Energy at the World Bank Group

The World Bank (IBRD and IDA) Energy, Mining, and Telecommunications Sector Board

James Bond
Director, Energy, Mining, and Telecommunications

Dominique Lallement
Manager, ESMAP

Mark Tomlinson
Sub-Saharan Africa region

Yoshihiko Sumi
East Asia and Pacific region

Hossein Razavi
Europe and Central Asia region

Susan Goldmark
Latin America and Caribbean region

Zoubeida Ladhibi-Belk
Middle East and North Africa region

Alastair McKechnie
South Asia region

Jean-Paul Pinard
IFC

A. David Craig
At large

Alain Barbu
At large

The World Bank relies on six Thematic Groups to set its agenda in the energy sector:

Energy Markets and Reform
Yves Albouy

Rural and Renewable Energy
Arun Sanghvi

Environment and Energy Efficiency
Robert Taylor

Oil and Gas
Charles McPherson

Mining Reform
Peter van der Veen

Global Climate Change
Charles Feinstein

IFC
Vivek Talvadkar
Director, Power

Jean-Paul Pinard
Associate Director, Power

Philippe Lietard
Director, Oil, Gas, and Mining

Maria da Graca Domingues
Manager, Oil, Gas, and Mining

Andreas Raczynski
Director, Environment

Louis Boorstin
Head, Environmental Projects Unit

MIGA
Gerald West
Senior Adviser, Infrastructure

Contact

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Fax.: 1.202.522.3018
### Glossary

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form / Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbl</td>
<td>barrel</td>
</tr>
<tr>
<td>CEGB</td>
<td>Central Electricity Generating Board, the publicly-owned electricity utility in England and Wales before privatization</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>CIS</td>
<td>Commonwealth of Independent States</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>CPEs</td>
<td>centrally-planned economies</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>EGAT</td>
<td>Electricity Generating Authority of Thailand</td>
</tr>
<tr>
<td>EGCO</td>
<td>Electricity Generating Company of Thailand - the generating arm of EGAT</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
</tr>
<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission of the United States of America</td>
</tr>
<tr>
<td>FSU</td>
<td>Former Soviet Union</td>
</tr>
<tr>
<td>FYR</td>
<td>Former Yugoslav Republic of (Macedonia)</td>
</tr>
<tr>
<td>Gtoe</td>
<td>million tonnes of oil equivalent</td>
</tr>
<tr>
<td>HFO</td>
<td>heavy fuel oil</td>
</tr>
<tr>
<td>IBRD</td>
<td>International Bank for Reconstruction and Development (the World Bank)</td>
</tr>
<tr>
<td>ICSID</td>
<td>International Center for the Settlement of Investment Disputes</td>
</tr>
<tr>
<td>IDA</td>
<td>International Development Association (the World Bank)</td>
</tr>
<tr>
<td>IEA</td>
<td>International Energy Agency</td>
</tr>
<tr>
<td>IFI</td>
<td>International Financial Institution - such as the World Bank, or one of the regional development banks</td>
</tr>
<tr>
<td>IPP</td>
<td>Independent Power Project - a generation plant that not built by the state utility</td>
</tr>
<tr>
<td>KEPCO</td>
<td>Korea Electricity and Power</td>
</tr>
<tr>
<td>KGAS</td>
<td>Korea Oil and Gas</td>
</tr>
<tr>
<td>kW</td>
<td>Kilowatt</td>
</tr>
<tr>
<td>LDC</td>
<td>local distribution company</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquid Natural Gas</td>
</tr>
<tr>
<td>LPG</td>
<td>Liquid Petroleum Gas</td>
</tr>
<tr>
<td>mb/d</td>
<td>million barrels per day</td>
</tr>
<tr>
<td>MtC</td>
<td>million tonnes of carbon</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
</tr>
<tr>
<td>NGO</td>
<td>non-governmental organization</td>
</tr>
<tr>
<td>OECD</td>
<td>Organization for Economic Co-operation and Development</td>
</tr>
<tr>
<td>OPEC</td>
<td>Organization of Petroleum-Exporting Countries</td>
</tr>
<tr>
<td>p/kWh</td>
<td>British pence per kiloWatt hour</td>
</tr>
<tr>
<td>PLN</td>
<td>Perusahaan Listrik Negara - Indonesia's publicly-owned electricity utility</td>
</tr>
<tr>
<td>PM</td>
<td>particulate matter</td>
</tr>
<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
</tr>
<tr>
<td>PV</td>
<td>photo-voltaic</td>
</tr>
<tr>
<td>RPI-X</td>
<td>a pricing formula based on the Retail Price Index</td>
</tr>
<tr>
<td>SOE</td>
<td>state-owned enterprise</td>
</tr>
<tr>
<td>SMP</td>
<td>system marginal price</td>
</tr>
<tr>
<td>toe</td>
<td>tonnes of oil equivalent</td>
</tr>
<tr>
<td>TPA</td>
<td>third party access</td>
</tr>
<tr>
<td>UN</td>
<td>United Nations</td>
</tr>
<tr>
<td>UNDP</td>
<td>United Nations Development Program</td>
</tr>
<tr>
<td>UNEP</td>
<td>United Nations Environment Program</td>
</tr>
<tr>
<td>WTI</td>
<td>West Texas Intermediate</td>
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</tbody>
</table>

#### World Bank

**Regional acronyms**

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
</tr>
</thead>
<tbody>
<tr>
<td>AFR</td>
<td>Sub-Saharan Africa</td>
</tr>
<tr>
<td>EAP</td>
<td>East Asia and the Pacific</td>
</tr>
<tr>
<td>ECA</td>
<td>Europe and Central Asia</td>
</tr>
<tr>
<td>LAC</td>
<td>Latin America and the Caribbean</td>
</tr>
<tr>
<td>MNA</td>
<td>The Middle East and North Africa</td>
</tr>
<tr>
<td>SAR</td>
<td>South Asia</td>
</tr>
</tbody>
</table>
Energy Sector Management Assistance Programme

ESMAP is a global technical assistance program sponsored by the World Bank and the United Nations Development Programme (UNDP) and managed by the World Bank. ESMAP focuses on the role of energy in economic development with the objective of contributing to poverty alleviation and economic progress, improving living conditions, and preserving the environment in developing countries and economies in transition.